EXHIBIT I

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

FORM 10-K

T 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 001-37419

PDC ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**95-2636730**
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: **(303) 860-5800**

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	NASDAQ Global Select Market

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 T 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 T

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 T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 T 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 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 T

The aggregate market value of our common stock held by non-affiliates on June 30, 2016 was $2.7 billion (based on the closing price of $57.61 per share as of the last business day of the fiscal quarter ending June 30, 2016).

As of February 15, 2017, there were 65,763,315 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We hereby incorporate by reference into this document the information required by Part III of this Form, which will appear in our definitive proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2016 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references in this report to "PDC Energy," "PDC," "the Company," "we," "us," "our," or "ours" refer to the registrant, PDC Energy, Inc., and all subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our remaining affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture owned 50 percent by PDC until its sale in October 2014. PDC is a Delaware corporation having reincorporated from Nevada in 2015.

GLOSSARY OF UNITS OF MEASUREMENTS AND INDUSTRY TERMS

Units of measurements and industry terms are defined in the Glossary of Units of Measurements and Industry Terms, included at the end of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations, and prospects. All statements other than statements of historical facts included in this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future: reserves, production, costs, cash flows and earnings; drilling locations and growth opportunities; capital expenditures and projects, including expected lateral lengths of wells, drill times and number of rigs employed; rates of return; operational enhancements and efficiencies; management of lease expiration issues; financial ratios; and midstream capacity and related curtailments.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying materials, we may use the terms “projection” or similar terms or expressions, or indicate that we have “modeled” certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or the industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- changes in worldwide production volumes and demand, including economic conditions that might impact demand;
- volatility of commodity prices for crude oil, natural gas, and natural gas liquids ("NGLs") and the risk of an extended period of depressed prices;
- reductions in the borrowing base under our revolving credit facility;
- impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement related to those laws and regulations, liabilities arising thereunder, and the costs to comply with those laws and regulations;
- declines in the value of our crude oil, natural gas, and NGLs properties resulting in further impairments;
- changes in estimates of proved reserves;
- inaccuracy of estimated reserves and production rates;
- potential for production decline rates from our wells being greater than expected;
- timing and extent of our success in discovering, acquiring, developing, and producing reserves;
- availability of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production and the impact of these facilities and regional capacity on the prices we receive for our production;
- timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- losses from our Gas Marketing segment exceeding our expectations;
- difficulties in integrating our operations as a result of any significant acquisitions, including our recent acquisitions in the Delaware Basin;
- increases or changes in operating costs, severance and ad valorem taxes, and increases or changes in drilling, completion and facilities costs;
- increases or adverse changes in construction costs and procurement costs associated with future build out of mid-stream related assets;
- future cash flows, liquidity, and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;
- our success in marketing crude oil, natural gas, and NGLs;

- effect of crude oil and natural gas derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital investments;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations and objectives for our future operations.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that could affect our business, financial condition, results of operations and cash flows. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. **We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.**

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

The Company

We are a domestic independent exploration and production company that acquires, produces, develops, and explores for crude oil, natural gas, and NGLs. Our operations are located in the Wattenberg Field in Colorado; the Utica Shale in southeastern Ohio; and, with the closing of our $1.76 billion acquisitions of proved producing, proved undeveloped, and unproved leaseholds in December 2016, in the Delaware Basin in Texas (see *"Business Strategy - Strategic acquisitions"* below).

As of December 31, 2016, we own an interest in approximately 2,900 gross (2,400 net) productive wells, of which approximately 25 percent are horizontal. We operate 88 percent of the wells in which we have an interest. We produced 22.2 MMBoe in 2016, including 0.2 MMBoe contributed from the newly acquired Delaware Basin assets, representing an increase of 44 percent compared to 2015. For the month ended December 31, 2016, we maintained an average production rate of 73 MBoe per day. This exit rate represents a 42 percent increase from December 2015. We were able to achieve this strong growth rate while maintaining a robust liquidity position, comprised of cash and cash equivalents and available capacity under our revolving credit facility totaling $932.4 million as of December 31, 2016. Our debt to EBITDAX ratio as of December 31, 2016, as defined in our revolving credit facility agreement, was 2.10 to 1.00, well within our compliance limit of 4.00 to 1.00. As of December 31, 2016, we had 341.4 MMBoe of proved reserves, 29 percent of which are proved developed, including 32.5 MMBoe related to acquisitions of properties in the Delaware Basin. Approximately 59 percent of our reserves at December 31, 2016 are liquids, which includes crude oil and NGLs. Our 341.4 MMBoe of total proved reserves as of December 31, 2016, represented an increase of 68.6 MMBoe, or 25 percent, relative to December 31, 2015. Our proved reserve additions were primarily a result of: 1) the development of longer lateral length well bores with higher working interests in the Wattenberg Field, which was driven by technology advancements, together with the ability to consolidate our leasehold position, and 2) the acquisitions of properties in the Delaware Basin.

Our Strengths

- ***Multi-year project inventory in premier crude oil, natural gas, and NGLs plays.*** We have a significant operational presence in two premier U.S. onshore basins providing us with approximately 2,600 potential horizontal drilling locations from our total proved and unproved leasehold. The primary focus for development is currently in the Wattenberg Field and the Delaware Basin. We believe that our inventory of drilling locations, the majority of which reflect 4,000 to 10,000 foot horizontal laterals, will allow us to continue to grow our proved reserves and production at attractive rates of return utilizing our current internal long-term commodity price projections and our current expected cost structure. Our 2017 drilling and completion operations are expected to specifically focus on the middle core of the Wattenberg Field and our newly acquired Delaware Basin assets. In the Wattenberg Field, we have identified a substantial inventory consisting of approximately 700 proved undeveloped horizontal drilling locations and an additional approximately 1,100 probable horizontal drilling locations. Through our acquisitions in the Delaware Basin, we added approximately 20 proved undeveloped horizontal drilling locations, which were included in the 785 gross potential drilling locations that were identified on our 62,500 net acres of leasehold. At the time of the initial acquisition, our undeveloped location count was based on wells expected to be drilled with horizontal lateral lengths ranging from 4,000 to 10,000 horizontal feet. We believe that with additional development and exploration activity, together with advances in technology, we may be able to access additional productive zones in the Delaware Basin, which could significantly increase our inventory of undeveloped locations.

- ***Strong liquidity position.*** As of December 31, 2016, we had a total liquidity position of $932.4 million, comprised of $244.1 million of cash and cash equivalents and $688.3 million available for borrowing under our revolving credit facility. During 2016, we raised in excess of $1.4 billion of new capital, net of issuance costs.

  - In March 2016, we raised $296.6 million, net of issuance costs, from the sale of 5.9 million shares of common stock.
  - In September 2016, we issued 9.1 million shares of common stock for net proceeds of $558.5 million, $400.0 million of 6.125% senior unsecured notes due in 2024 ("2024 Senior Notes") for net proceeds of $392.2 million, and $200.0 million of 1.125% convertible senior notes due in 2021 for net proceeds of $193.9 million.

- We also issued 9.4 million shares of common stock valued at $690.7 million in December 2016 as partial consideration to the sellers for the initial Delaware Basin acquisition.
- In December 2016, we increased the aggregate commitment under our revolving credit facility to $700 million.

We intend to continue to manage our liquidity position through investment in projects with attractive rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative program, and access to capital markets from time to time.

- ***Balanced and diversified portfolio across two premier U.S. onshore basins.*** We believe we have multiple years of attractive drilling opportunities in both the Wattenberg Field and the Delaware Basin. The completion of the acquisitions of Delaware Basin properties provides us the ability to allocate capital between the two basins to diversify our risk. We expect that this will improve overall economic results and drive our future production and reserve growth. We believe that we will be able to transfer much of our management expertise gained over the years in the Wattenberg Field to the newly acquired Delaware Basin assets. The successful development and exploitation of the acquired leasehold in the Delaware Basin will include execution of our asset integration plan, which consists of transferring our technological expertise to the Delaware Basin, beginning down spacing initiatives, testing various completion designs, successfully developing multiple benches, maintaining an intense focus on cost structure, and utilizing existing personnel and retaining experienced staff. Additionally, we expect the increased geographical diversity of our portfolio to mitigate risks associated with a single dominant producing area, as each basin will have its own operating and competitive dynamic in terms of commodity price markets, service cost areas, takeaway capacity, and regulatory and political considerations.

- ***Significant operational control in our core areas.*** We have, and expect to continue to have, a substantial degree of operational control over our properties. As a result of successfully executing our strategy of acquiring largely concentrated acreage positions with a high working interest, we operate and manage approximately 88 percent of all wells in which we have an interest across all of our operating basins. Our control allows us to manage our drilling, production, operating and administrative costs, and to leverage our technical expertise in our core operating areas. Our leaseholds that are held-by-production further enhance our operational control by providing us flexibility in selecting drilling locations based upon various operational criteria.

  In the Wattenberg Field, our operational control is attributable to our high working interest leasehold and large contiguous acreage blocks, which have been enhanced as a result of a 2016 acreage trade, and because substantially all of our Wattenberg Field acreage is held-by-production. We remain flexible in terms of rig activity and capital deployment due to short-term rig contracts and we are confident in our ability to manage held-by-production acreage in the Wattenberg Field in order to maintain our current level of operational control. As a result, we can adjust our drilling plans if commodity prices deteriorate in order to manage cash flows from operations relative to cash flows from investing activities.

  In the Delaware Basin, our average working interest in our properties is approximately 92 percent and we operate nearly 100 percent of those properties. Additionally, we own and operate certain midstream assets in the Delaware Basin and believe this will allow for timely system expansion, well connections, water supply for completion operations, and water disposal. Approximately 30 percent of the properties acquired in the Delaware Basin were held-by-production as of December 31, 2016. The leaseholds in the Delaware Basin require a more active drilling program than in the Wattenberg Field, and in certain cases, continuous operations to maintain the underlying leaseholds. With our high percentage of operated leaseholds in the Delaware Basin, we expect to have adequate control over the location and pace of our development to manage lease expiration issues. While we believe that our current Delaware Basin drilling plan should meet these obligations for the next few years, in the event that we do not meet the obligations for certain leases, we anticipate that we will make any necessary bonus extension payments, or we will seek to renew or, re-lease in order to retain the leases. However, the payments required to do so may be significant and we may not be successful in such efforts.

- ***Utilizing technology to focus on efficiency.*** In the Wattenberg Field, we have a proven track record of continuing improvement in both costs and productivity of our existing well operations. Our efficiencies are driven by a focus on the use of multi-well pad drilling, extended reach lateral well development, increased fracture stimulation stage density, enhanced fracture stimulation completion design, and improved drilling efficiencies. In 2016, approximately 65 percent of our Wattenberg Field horizontal well spuds were mid- or extended-reach laterals that ranged from approximately 7,000 to 9,500 horizontal feet in length. We have implemented plug-and-perforation completion techniques on all new wells, and increased the number of completion stages to provide a potential uplift to our new well production. We also began using a mono-bore drilling design to reduce drill times and well costs. Through the combination of these techniques, our drilling team has improved our drilling efficiencies with average drill results increasing to approximately 2,200 feet drilled per day in 2016 from approximately 1,800 feet drilled per day in 2015. We believe that we can generate substantial value by leveraging and applying our operating experience in the Wattenberg Field and the Utica Shale to our Delaware Basin properties.

- ***Commodity derivative program.*** Our active use of commodity derivative instruments to protect our investment returns and cash flows was particularly important through the severe commodity price downturn in 2015 and 2016. We have continued this program and have entered into commodity derivative instruments to mitigate a portion of our short-term future exposure to commodity price fluctuations, including crude oil and natural gas collars, fixed-price swaps, and basis swaps. While our commodity derivative program limits the upside benefits we may otherwise receive during periods of higher commodity prices, the program helps protect a portion of our cash flows, borrowing base, and liquidity during periods of depressed commodity prices. We strive to scale our

overall hedging position to be appropriate relative to our current and expected level of indebtedness and consistent with our goals of preserving balance sheet strength and substantial liquidity, as well as our internal price view. In 2016 and 2015, net settled derivatives contributed a significant portion of our cash flows from operating activities, thereby mitigating the effect of the depressed commodity prices. Based upon our hedge position at forward strip pricing at year-end 2016, our derivatives are now in a net liability position of $70.0 million. Therefore, because of the normal settlement of our higher value derivatives that occurred in 2015 and 2016, and because our remaining unsettled derivative contracts have future settlement prices closer to the current forward price curve, the settlement of these instruments are not expected to be a significant source of cash flow, and may result in cash outflows in 2017 and 2018.

As of December 31, 2016, we had commodity derivatives positions covering approximately 8.5 MMBbls and 4.9 MMBbls of crude oil production for 2017 and 2018, respectively. As of the same date, we had hedged approximately 35.2 Bcf and 46.5 Bcf of natural gas production for 2017 and 2018, respectively. The details of these transactions are described in the footnotes to our consolidated financial statements included elsewhere in this report. We do not currently have any commodity derivatives for any of our NGL production.

- ***Strong environmental, health and safety compliance programs, and community outreach.*** We have focused on establishing effective environmental, health and safety programs that are intended to promote safe working practices for our employees and contractors and to help earn the trust and respect of land owners, regulatory agencies, and public officials. We believe this is an important part of our strategy in competing in today's intensive regulatory and public debate climate. We are also dedicated to being an active and contributing member of the communities in which we operate. We share our success with these communities in various ways, including charitable giving and community event sponsorships.

- ***Strong management team and operational capabilities.*** We have strong and stable management, led by our executive management team. Each member of the team has between 10 and 30 years of experience in the energy and natural resource industry. This experience collectively spans expertise in land, reservoir analysis, operations, accounting, finance, strategy, and general operations, and has helped us continue our growth through periods of commodity price pressure, cost inflation, and challenging operating environments.

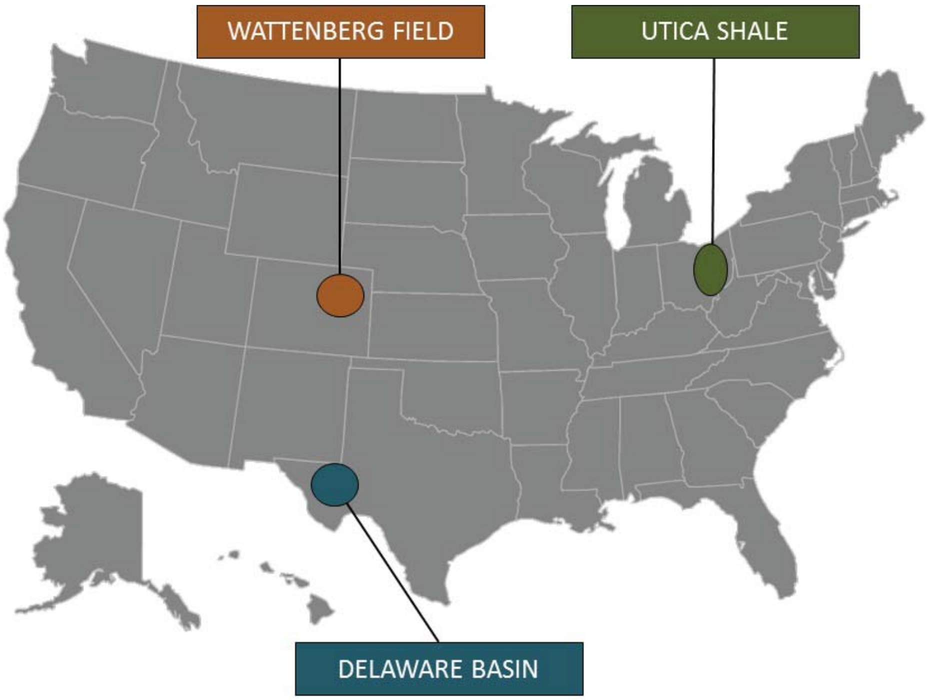
Business Strategy

Our long-term business strategy focuses on generating stockholder value through the acquisition, exploration, and development of crude oil and natural gas properties. We are focused on the growth of our reserves, production, and cash flows through organic exploration and development of our existing and acquired leasehold in our horizontal drilling programs. Our operational focus is concentrated with a substantial presence in two basins. We pursue various midstream, marketing, and cost reduction initiatives designed to increase our per unit operating margins while maintaining a disciplined financial strategy focused on providing sufficient liquidity and balance sheet strength to execute our business strategy.

We focus on horizontal development drilling programs in resource plays that offer repeatable results and the potential for attractive returns on investment in a range of commodity price environments. Our inventory of drilling locations supports our planned organic growth over the next several years. We expect our drilling and completion activity to drive increases in proved reserves, production, and cash flows. In addition to development drilling, we routinely review acquisition and acreage swap opportunities in our core areas of operations. We believe we can extract additional value from such transactions through production optimization opportunities and increases in our working interests in our development drilling locations afforded by more concentrated acreage positions. As a result, once we have established a significant presence in an area, the use of bolt-on acquisitions and acreage trades can potentially provide synergies that result in additional economies of scale. We also pursue a limited and disciplined exploration program with the goal of replenishing our portfolio with new exploration projects capable of positioning us for significant production and reserve growth in future years.

Development drilling

The following map presents the general locations of our development and production activities as of December 31, 2016:



Our leasehold interests covers properties with developed and undeveloped crude oil, natural gas, and NGLs resources. We own approximately 2,900 gross (2,400 net) wells in our three operating basins. Our previously-announced 2017 capital investment program contemplates expenditures of between $725 million and $775 million. Due to recent cost escalation for services in our core areas and the modification of our drilling schedule in the Delaware Basin, where we have accelerated the deployment of an additional drilling rig, we currently expect that our 2017 capital investment will be at or near the high end of the range. These changes to our capital investment outlook are not expected to impact our 2017 production estimate, as the incremental well drills are contemplated to be turned-in-line to sales late in the year.

We have allocated substantially all of our 2017 capital investment program to our higher-return projects in the Wattenberg Field and Delaware Basin, and have elected to defer drilling operations in the Utica Shale. Based on our current production and commodity price outlook for 2017, we continue to expect capital investments to exceed cash flows from operations by approximately $200 million. Our debt to EBITDAX ratio, as defined in our revolving credit facility agreement, is expected to decrease in 2017 based on production and operational cash flow growth. A deterioration of commodity prices could negatively impact our results of operations, financial condition, and future development plans. We may increase or decrease our 2017 capital investment program during the year as a result of, among other things, changes in commodity prices or our current internal long-term outlook for commodity prices, requirements to hold acreage, the cost of services for drilling and well completion activities, drilling results, changes in our borrowing capacity, a significant change in cash flows, regulatory issues, requirements to maintain continuous activity on leaseholds or acquisition and/or divestiture opportunities. If such changes result in our election to deploy additional capital investment, amounts may further exceed our cash flow from operations.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays. Based on our current drilling program, we have an inventory of 700 gross proved undeveloped horizontal drilling locations and approximately 1,100 gross probable horizontal drilling locations. These locations are in the core Wattenberg Field, which is further delineated between the inner, middle, and outer core. In 2017, we expect to continue to realize additional capital efficiencies through drilling extended length laterals, an increased number of fracturing stages, plug-and-perforation completions, enhanced well orientation, and mono-bore drilling. We plan to drill standard reach lateral (“SRL”), mid-length lateral (“MRL”), and extended reach lateral (“XRL”) wells in 2017, the majority of which will be in the middle core area of the field. Wells in the Wattenberg Field typically have productive horizons at depths of approximately 6,500 to 7,500 feet below the surface. In 2017, to help balance our priorities, we now anticipate spudding 137 operated wells and turning-in-line to sales, approximately 139 horizontal operated wells as outlined below.

	SRL	MRL	XRL
Estimated average lateral length (in feet)	4,200	6,900	9,500
Expected drilling days (spud-to-spud)	7	10	12
Estimated percentage of 2017 wells spud	31%	33%	36%
Estimated percentage of 2017 wells turned-in-line	35%	30%	35%
Estimated cost per well (in millions)	$2.5	$3.5	$4.5

The 2017 capital investment outlook is now approximately $470 million in the Wattenberg Field and anticipates a three to four-rig drilling program based on our current commodity price outlook. Approximately $460 million of our 2017 capital investment program is expected to be invested in development activities in the Wattenberg Field, comprised of approximately $440 million for our operated drilling program and approximately $20 million for wells drilled and operated by others. The remainder of the Wattenberg Field capital investment program is expected to be used for miscellaneous workover and capital projects.

Delaware Basin. In December 2016, we closed a series of acquisitions providing us a total of approximately 62,500 net acres in Reeves and Culberson Counties, Texas (see "*Business Strategy-Strategic acquisitions*" below). In 2017, our investment outlook now contemplates operating a two-rig to four-rig program at various times throughout the year and deploying the third rig in late Februay 2017. Total capital investment in the Delaware Basin is estimated to be $300 million, of which approximately $235 million is allocated to spud 31 wells and turn-in-line an estimated 26 wells. Based on the timing of our operations and the requirements to hold acreage, we may adapt our capital investment program to drill wells in addition to those currently anticipated, as we are continuing to analyze the terms of the leaseholds related to our recent acquisitions of properties in the basin. We plan to drill 20 wells in our eastern acreage block, nine wells in our central acreage block, and two wells in our western acreage block, with the majority of wells targeting the Wolfcamp A and B zones. Of the 26 planned turn-in-lines, 14 are expected to have laterals of approximately 10,000 horizontal feet with completion stages currently expected to range from approximately 100 to 125 feet. Similarly spaced completions are anticipated for the remaining 12 turn-in-lines. Wells in the Delaware Basin typically have productive horizons at depths of approximately 9,000 to 11,000 feet below the surface. Estimated well costs for SRL, MRL, and XRL wells are approximately $7.1 million, $8.8 million and $10.5 million, respectively. We plan to invest approximately $35 million for leasing, seismic, and technical studies with an additional $30 million for midstream related projects including gas connections, salt water disposal wells, and surface location infrastructure.

Utica Shale. At this time, we are currently evaluating all of our strategic alternatives with respect to our Utica Shale position. As a result of such evaluation, we are deferring our 2017 planned expenditure of $18 million to drill, complete, and turn-in-line two wells in Guernsey County. In 2017, our capital investment program for the Utica Shale is expected to include between $2 million to $3 million for additional leasing. Such leasing may be necessary to complete certain drilling operations if we decide to continue development of our existing position in the northern portion of our acreage.

Strategic acquisitions

As part of our overall growth strategy, we examine and evaluate acquisition opportunities as they present themselves and pursue those that meet our strategic plan and that we believe will increase stockholder value. We seek properties with large undeveloped drilling upside where we believe we can utilize our operational expertise to grow production and proved reserves. In addition, we may pursue opportunities to trade acreage with other producers or complete small bolt-on acquisitions in order to optimize our portfolio by consolidating and concentrating our core assets. The creation of large, contiguous acreage blocks through the trading of properties or bolt-on acquisitions provides the opportunity to optimize drilling activities and add more extended-reach lateral wells to our drilling program, while increasing our working interests in the related wells. We have an experienced team of management, engineering, geosciences, and commercial professionals who identify and evaluate acquisition opportunities. Our acquisition activity in 2017 is expected to be focused on our two most significant assets, the Wattenberg Field and Delaware Basin.

Delaware Basin. We recently engaged in the process of searching for and evaluating a large-scale acquisition in a new U.S. onshore basin capable of creating material long-term value-added growth, focusing on four key criteria: top-tier acreage in core geologic positions, significant drilling inventory with additional expansion through down spacing, portfolio optionality for capital allocation and diversification, and the ability to deliver long-term increases in net asset value per share. Having determined that they met these criteria, in December 2016, we closed the purchases of an aggregate of approximately 62,500 net acres, in Reeves and Culberson Counties, Texas, through two transactions, for an aggregate consideration to the sellers of approximately $1.76 billion.

- The first transaction consisted of the acquisition of certain producing properties and approximately 57,900 acres for approximately $952.1 million in cash and the issuance of 9.4 million shares of our common stock valued at approximately $690.7 million at the time the acquisition closed, for total consideration of approximately $1.64 billion.
- The second transaction occurred shortly thereafter and included certain developed assets and 4,600 net acres of undeveloped leasehold that is complementary to the initial transaction. This transaction was paid for in cash of $120.6 million.

The the purchase prices for the acquisitions remain subject to certain post-closing adjustments as of the date of this report. We expect that it may take into mid-2017 until all post-closing adjustments are settled. See footnotes titled *Properties and Equipment - Delaware*

Basin Acreage Acquisition and *Business Combination* to our consolidated financial statements included elsewhere in this report for further information regarding these two acquisitions.

Selective exploration

Historically, we have pursued a disciplined exploration program intended to replenish our portfolio and to position us for production and reserve growth in future years. When doing so, we attempt to identify potential plays in their early stages in order to accumulate significant leasehold positions prior to competitive forces driving up the cost of entry and to invest in leasehold positions that are near existing or emerging midstream infrastructure. Our contemplated near-term exploration activity will be occurring in the Delaware Basin as there are multiple zones that have not seen development activity sufficient to record proved reserves. Such zones could provide additional potential drilling locations and/or proved reserves.

Business Segments

We divide our operating activities into two segments: (1) Oil and Gas Exploration and Production and (2) Gas Marketing.

Oil and Gas Exploration and Production

The results of our Oil and Gas Exploration and Production segment primarily reflect revenues and expenses from the production and sale of crude oil, natural gas, and NGLs, commodity price risk management, and well operations. The exploration for and production of crude oil, natural gas, and NGLs involves the acquisition or leasing of mineral rights and related surface rights. Prior to development of these properties, we assess the economic viability of potential well development opportunities. We then develop the reserves through the permitting, drilling and completion of oil and gas wells, which are then turned-in-line to sales and production. Following completion, we operate and maintain the producing wells while managing associated production, operating, and transportation costs. At the end of a well's economic life, the well is plugged and surface disturbances surrounding the well and producing facilities are remediated. The Oil and Gas Exploration and Production segment's most significant customers are Suncor Energy Marketing, Inc., DCP Midstream, LP ("DCP"), Aka Energy Group, LLC ("Aka"), Concord Energy, LLC, and Bridger Energy, LLC. Sales to each of these parties constitute more than 10 percent of our revenues in 2016. We believe that the loss of any purchaser or the aggregate loss of several customers could be managed by selling to alternative purchasers given the liquidity in the market for the sale of hydrocarbons.

Within the Oil and Gas Exploration and Production Segment, our crude oil, natural gas, and NGLs production is gathered, marketed and sold as follows:

- *Crude oil.* In the Wattenberg Field, our crude oil is sold under various purchase contracts with monthly and longer term pricing provisions based on New York Mercantile Exchange ("NYMEX") pricing, adjusted for differentials. Since we do not refine any of our crude oil production, we sell to companies that either transport or resell the commodity, or process the crude oil in their own facilities. Title to the crude oil transfers at the time the crude oil leaves our lease site and is either placed in a truck or enters a pipeline. We have entered into commitments ranging in term from one month to over three years to deliver crude oil to competitive markets, resulting in improved average overall deductions of $4.39 for 2016 compared to $9.95 for 2015. During 2016, there was sufficient take away capacity in the Wattenberg Field for crude oil. This was a function of decreases in drilling activity and corresponding decreases in production from other producers, and the completion of additional crude oil pipelines to the Cushing, Oklahoma market. We believe that there will continue to be adequate take away capacity for crude oil through either pipeline or trucking options in the Wattenberg Field in the near- and mid-term. We continue to pursue various alternatives with respect to crude oil transportation, with a view toward further improving pricing and increasing the amount of crude oil transported by pipeline and limiting our use of trucking. For example, in mid-2015, we began delivering crude oil in accordance with our long term commitment to the White Cliffs Pipeline, LLC ("White Cliffs") pipeline. Our volume of crude oil sales going through the White Cliffs pipeline in 2016 was 16 percent of our Wattenberg Field crude oil production compared to 23 percent during the second half of 2015. By having a variety of off-take arrangements, we seek to optimize our marketing to result in the best possible net realized price per barrel. The White Cliffs agreement is one of several we have entered into to facilitate deliveries of a portion of our crude oil to the Cushing, Oklahoma market. In addition to the White Cliffs agreement, we have signed a long-term agreement with Saddle Butte Rockies Midstream, LLC for gathering of crude oil at the wellhead by pipeline from several of our producing pads in the Wattenberg Field, with a view toward minimizing truck traffic, increasing reliability, reducing the overall physical footprint of our well pads, and reducing emissions. We began delivering crude oil into this pipeline during the fourth quarter of 2015. The system became fully operational in 2016 and we did not experience any subsequent curtailment of operations due to lack of takeaway capacity for crude oil in the basin. We do not expect to experience any curtailments in 2017.

  In the Delaware Basin, our crude oil production is sold at the wellhead and transported via trucks to pipelines that deliver the oil to the Midland, Texas, crude oil market. Given the increased level of activity in the form of acquisitions, leasing, and the increases in rig count in the Delaware Basin over the last six months, we expect the balance between production and pipeline takeaway capacity to tighten during 2017. At the current time, there are pipeline, truck and rail pathways out of the basin, all of which are available to us. We are evaluating near-term and longer-term solutions that contemplate the increased activity levels we expect, as well as our anticipated future production. These may include longer-term sales agreements.

In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual well site based on NYMEX pricing, adjusted for differentials, and is typically transported by the purchasers via truck to local refineries, rail facilities, or barge loading terminals on the Ohio River. To date, we have not experienced any significant issues with take away capacity in this region for our crude oil.

- *Natural gas.* We sell substantially all of our natural gas to midstream service providers and marketers. We have entered into firm gathering and processing agreements for all of our natural gas production in the Wattenberg Field to ensure there is infrastructure available to process the gas and deliver our product to market. In the Wattenberg Field, the majority of our leasehold is dedicated to our primary midstream provider, DCP, which gathers and processes natural gas produced in the basin and sells our residue gas to various markets. We also sell natural gas into a system owned and operated by Aka, and have committed production from dedicated acreage and a drilling program with a specific number of wells to be drilled and completed by the end of 2017. Pursuant to the agreement, Aka is required to install and operate, or contract for the use of, facilities necessary to receive and purchase the production volumes committed under the agreement.

In the Wattenberg Field, title to the natural gas transfers at the custody transfer meter located at our wellheads, except when we have multiple wells being gathering to a common pad, in which case the natural gas is sold as it passes through the custody transfer meter located on our well pads after water and crude oil have been separated from the natural gas stream. Our Wattenberg Field natural gas is transported through third-party gathering systems and pipelines where we incur gathering, processing, and transportation expenses via percent-of-proceeds ("POP") contracts whereby the gatherer/processor markets the natural gas and NGLs on a best efforts basis and then retains a portion of the revenue attributable to the residue gas and NGL sales. Substantially all of the natural gas that we produce in the Wattenberg Field is sold by the midstream service providers and is priced based on Colorado Interstate Gas ("CIG") or local distribution company monthly/daily pricing provisions. There have been periods in the past where transportation of natural gas was a significant issue, however, such has not been the case recently based on pipeline and development activity by midstream providers, as well as relatively decreased activity levels by other operators in the other areas of the Wattenberg Field. We anticipate gathering system pressures to vary throughout the year, with increases coinciding with the warmer summer months. We plan for these increases and work with our mid-stream providers to manage production during these times. There was a new processing plant built in the portion of the Wattenberg Field in mid-2015 that provided significant relief and when coupled with the overall decrease in activity in the field near our operations, we did not experience any curtailments in 2016. We recently signed a contract to support a midstream provider's construction of an additional processing plant in the area. This midstream provider expects the plant to be placed into service towards the end of 2018. If the midstream provider is delayed in its expansion efforts, we could experience higher line pressures which could impact our production volumes. In 2016, approximately 90 percent of our production in the Wattenberg Field was delivered from horizontal wells, with the remaining 10 percent coming from vertical wells. The horizontal wells are less prone to issues than the vertical wells in that they are newer and have greater producing capacity and higher formation pressures and therefore tend to be more resilient from periodic gas system pressure issues. Based on the expected activity levels and production in the region coupled with the current and committed construction activities in the area, we anticipate that we will have adequate takeaway capacity in the region for the next few years.

In the Delaware Basin, title to the natural gas transfers at the delivery point off of our gathering systems. In certain cases, we are paid the total value of the natural gas and the value of the NGLs processed by the purchasers, and we pay specific processing costs or fees. In other cases, we incur gathering, processing, and transportation expenses via POP contracts whereby the gatherer/processor retains a portion of the revenue attributable to the residue gas and NGL sales. Our Delaware Basin midstream service providers sell the residue gas at prices based on indexed prices per MMBtu using either the Waha or El Paso Permian monthly and daily price provisions. These index prices are established monthly and daily in the gas trading market, and represent the value of the natural gas delivered to the NYMEX Henry Hub delivery point, net of the transportation and margin embedded in the basis differential.

In the Utica Shale, natural gas produced in our northern acreage is gathered and processed pursuant to a firm gathering and processing agreement with MarkWest Utica EMG ("MarkWest") under a fee based contract, while natural gas produced in our southern acreage is gathered and processed by Blue Racer Midstream LLC ("Blue Racer"), also under a fee based contract. As a result, we receive the full revenue stream attributable to the residue gas and NGL sales, less the applicable gathering and processing fees. The natural gas sales from both the Blue Racer plant and the MarkWest plant are based on TETCO M-2 index pricing per MMbtu delivered to the plant. We anticipate that the significant Appalachian pipeline differentials that impact our Utica Shale natural gas, which make economics challenging, will continue to be highly volatile into 2017.

- *NGLs.* Our NGL sales are priced based upon the components of the product and are correlated to the price of crude oil. In the Wattenberg Field, all of our NGLs are sold by the midstream service provider at the tailgate of the processing plants based on a combination of prices from the Conway hub in Kansas and Mt. Belvieu in Texas where the NGLs are marketed.

As noted above, the value of the NGLs extracted from the natural gas by our midstream providers in the Delaware Basin is based on processing contracts. Based on the percentage of NGLs in the natural gas stream, we receive the net proceeds of the NGLs processed by the midstream providers as sold into the Mt. Belvieu market.

In the Utica Shale, our NGLs are fractionated and marketed by MarkWest and Blue Racer and sold based on month-to-month pricing in various markets. Our NGL production is sold by our midstream service providers under both short- and long-term contracts.

Gas Marketing

Our Gas Marketing segment is comprised solely of the operating activities of our wholly-owned subsidiary Riley Natural Gas ("RNG"). RNG specializes in the purchase, aggregation, and sale of natural gas production in the Appalachian Basin. The natural gas is marketed to third-party marketers, natural gas utilities, and industrial and commercial customers through transportation services provided by regulated interstate/intrastate pipeline companies. RNG is party to long-term firm transportation, sales, and processing agreements for pipeline capacity through August 2022. RNG acquired these firm transportation rights and associated agreements at a time when PDC owned operating interests in oil and natural gas wells through a joint venture in the Appalachian Basin referred to as PDCM. Although PDC sold its interest in PDCM in 2014, RNG retained the majority of its firm natural gas transportation commitment. Financial results from our gas marketing segment have resulted in an operating loss contribution of $1.5 million, $0.8 million, and $0.4 million, for 2016, 2015, and 2014, respectively. As of December 31, 2016, the amount owed for this long-term firm transportation, sales and processing agreement was approximately $19.1 million. This long-term pipeline capacity commitment was made on behalf of our third-party producers, and also includes an unutilized portion; however, we remain obligated to fulfill this commitment regardless of whether or not our third-party producers meet their commitments. As natural gas prices remain depressed, certain third-party producers under our Gas Marketing segment have continued to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, no counterparty default losses have been material to us. As of December 31, 2016, we recorded an allowance for doubtful accounts of approximately $1.3 million associated with such activity. We have initiated several legal actions for breach of contract, collection, and related claims against certain third-party producers, which have to date resulted in two default judgments. We expect RNG's expenses to exceed its revenues by approximately $1 million to $2 million per year through 2022, assuming a continuation of current economic conditions. After the long-term firm transportation agreements expire, we expect to discontinue this segment.

For additional information regarding our business segments, see the footnote titled *Business Segments* to our consolidated financial statements included elsewhere in this report.

Properties

Productive Wells

The following table presents our productive wells:

	Productive Wells As of December 31, 2016					
	Crude Oil		Natural Gas		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	669	436.8	2,193	1,908.0	2,862	2,344.8
Delaware Basin	33	31.5	—	—	33	31.5
Utica Shale	27	22.2	3	3.0	30	25.2
Total productive wells	729	490.5	2,196	1,911.0	2,925	2,401.5

Proved Reserves

The following table presents our proved reserve estimates as of December 31, 2016, based on reserve reports prepared by our independent petroleum engineering consulting firms, Ryder Scott Company, L.P. ("Ryder Scott"), and Netherland, Sewell & Associates, Inc. ("NSAI"), and related information:

	Proved Reserves at December 31, 2016					
	Proved Reserves (MMBoe)	**% of Total Proved Reserves**	**% Proved Developed**	**% Liquids**	**Proved Reserves to Production Ratio (in years) (1)**	**2016 Production (MBoe)**
Wattenberg Field	305.3	89%	29%	58%	14.6	20,945
Delaware Basin	32.5	10%	22%	68%	15.2	178
Utica Shale	3.6	1%	100%	56%	3.4	1,053
Total proved reserves	341.4	100%	29%	59%	16.2	22,176

(1) As the Delaware Basin properties were purchased in December 2016, we annualized the calculation for the Delaware Basin ratio - based on December production.

Our proved reserves are sensitive to future crude oil, natural gas, and NGLs sales prices and the related effect on the economic productive life of producing properties. Increases in commodity prices may result in a longer economic productive life of a property or result in recognition of more economically viable proved undeveloped reserves, while decreases in commodity prices may result in negative impacts of this nature.

All of our proved reserves are located onshore in the U.S. Our proved reserve estimates are prepared using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and other applicable SEC rules. As of December 31, 2016, our proved reserves, including our proportionate share of our affiliated partnerships' reserves, in the Wattenberg Field and Utica Shale have been estimated by Ryder Scott and our reserves in the Delaware Basin were estimated by NSAI. Both Ryder Scott and NSAI are independent professional engineering firms.

We have a comprehensive process that governs the determination and reporting of our proved reserves. As part of our internal control process, our reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, land and accounting personnel for adherence to SEC guidelines through a detailed review of land and account records, available geological and reservoir data, and production performance data. The process includes a review of applicable historical costing, working and net revenue interests, and performance data. The internal team compiles the reviewed data and forwards the data to Ryder Scott and NSAI.

When preparing our reserve estimates, neither Ryder Scott nor NSAI independently verifies the accuracy and completeness of information and data furnished by us with respect to ownership interests, production volumes, well test data, historical costs of operations and development, product prices or any agreements relating to current and future operations of properties, and sales of production. Ryder Scott and NSAI prepare estimates of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods and with a level of detail we deem appropriate. The final estimated reserve reports are those as prepared by Ryder Scott and NSAI and are reviewed by our engineering staff and management prior to issuance by the independent professional reserve engineering firms.

The professional qualifications of our internal lead engineer primarily responsible for overseeing the preparation of our reserve estimates, as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers, qualifies this individual as a Reserve Estimator. This person holds a Bachelor of Science degree in Petroleum and Chemical Refining Engineering with a minor in Petroleum Engineering, has over 40 years of experience in reservoir engineering, is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and is a registered Professional Engineer in the State of Colorado.

The SEC's reserve rules allow the use of techniques that have been proved effective by evaluation of actual production from projects in the same reservoir or an analogous reservoir or by other observational evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. We used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies, and seismic data and interpretation to calculate our reserve estimates. All of our proved undeveloped reserves conform to the SEC five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of each location's initial booking date. The SEC has also established that pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of month prices for the preceding 12 months. The NYMEX prices used in preparing the reserves are then adjusted by the required adjustments related to energy content, location and basis differentials, and other marketing deductions to arrive at the net realized price. The SEC NYMEX prices used in the preparation of reserves are as follows:

	As of December 31,		
	2016	2015	2014
Crude oil (SEC NYMEX - $/Bbl)	$ 42.75	$ 50.28	$ 94.99
Natural gas (SEC NYMEX - $/MMBtu)	$ 2.48	$ 2.59	$ 4.35

Reserve estimates involve judgments and cannot be measured exactly. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data, and economic changes. Neither the estimated future net cash flows nor the standardized measure of discounted future net cash flows ("standardized measure") is intended to represent the current market value of our proved reserves. For additional information regarding both of these measures, as well as other information regarding our proved reserves, see the *Supplemental Information Unaudited - Crude Oil and Natural Gas Information - Unaudited* provided with our consolidated financial statements included elsewhere in this report. The following tables provide information regarding our estimated proved reserves:

	As of December 31,		
	2016	2015	2014
Proved reserves			
Crude oil and condensate *(MMBbls)*	118	99	101
Natural gas *(Bcf)*	834	661	537
NGLs *(MMBbls)*	84	64	60
Total proved reserves *(MMBoe)*	341	273	250
Proved developed reserves *(MMBoe)*	98	70	75
Estimated undiscounted future net cash flows *(in millions)* (1)	$ 2,681	$ 2,259	$ 4,938
Standardized measure *(in millions)*	$ 1,421	$ 1,097	$ 2,306
PV-10 (*in millions*) (2)	$ 1,675	$ 1,338	$ 3,450

(1) Amount represents aggregate undiscounted future net cash flows, before income taxes, estimated by Ryder Scott and NSAI of approximately $3.3 billion, $2.8 billion, and $7.3 billion as of December 31, 2016, 2015, and 2014, respectively, less an internally-estimated undiscounted future income tax expense of approximately $0.6 billion, $0.5 billion, and $2.3 billion, respectively.

(2) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. GAAP, but rather should be considered in addition to the standardized measure. See Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure.

The following table presents our estimated proved developed and undeveloped reserves by category and area:

	As of December 31, 2016				
Operating Region/Area	Crude Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Crude Oil Equivalent (MMBoe)	Percent
Proved developed					
Wattenberg Field	25.5	240.6	21.7	87.4	26%
Delaware Basin	3.4	13.9	1.6	7.2	2%
Utica Shale	1.1	9.9	0.9	3.6	1%
Total proved developed	30.0	264.4	24.2	98.2	29%
Proved undeveloped					
Wattenberg Field	76.6	520.6	54.5	217.9	64%
Delaware Basin	11.6	48.7	5.6	25.3	7%
Utica Shale	—	—	—	—	—%
Total proved undeveloped	88.2	569.3	60.1	243.2	71%
Total proved reserves					
Wattenberg Field	102.1	761.2	76.2	305.3	89%
Delaware Basin	15.0	62.6	7.2	32.5	10%
Utica Shale	1.1	9.9	0.9	3.6	1%
Total proved reserves	118.2	833.7	84.3	341.4	100%

We are showing two different alternative price scenarios for crude oil as its value currently influences our proved reserves and PV-10 value most significantly. We have performed a sensitivity analysis of our proved reserve estimates as of December 31, 2016, to present sensitivities associated with both lower and higher crude oil prices. Replacing the 2016 NYMEX commodity prices used in estimating our reported proved reserves with those shown on the table below, and leaving all other parameters unchanged, results in a changes to our estimated proved reserves as shown below.

	Pricing Scenario - NYMEX					
	Crude Oil (per Bbl) (1)	**Natural Gas (per MMBtu) (1)**	**Proved Reserves (MMBoe)**	**% Change from December 31, 2016 Estimated Reserves**	**PV-10 (in Millions)**	**PV-10 % Change from December 31, 2016 Estimate Reserves**
2016 SEC Reserve Report	$ 42.75	$ 2.48	341.4	—	$ 1,675.0	—
Alternate Price Scenarios:						
Lower Price Scenario	$ 30.00	$ 2.48	326.5	(4)%	$ 705.7	(58)%
Higher Price Scenario	$ 50.00	$ 2.48	345.7	1 %	$ 2,247.0	34 %

(1) These prices are the SEC NYMEX prices applied to the calculation of the PV-10 value. Such prices have been applied consistently across each pricing scenario to include the impact of adjusting for deductions for any basin differentials, transportation fees, contractual adjustments, and any Btu adjustments we experienced for the respective commodity.

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage:

	As of December 31, 2016					
	Developed		Undeveloped		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	96,700	89,200	7,700	6,300	104,400	95,500
Delaware Basin	19,586	18,664	49,645	43,837	69,231	62,501
Utica Shale	5,454	4,291	61,862	58,162	67,316	62,453
Total acreage	121,740	112,155	119,207	108,299	240,947	220,454

Substantially all of our undeveloped acreage in the Wattenberg Field is related to leaseholds that are held-by-production. In the Wattenberg Field, approximately 1 percent, 2 percent, and 1 percent of our undeveloped leaseholds are scheduled to expire during 2017, 2018 and 2019, respectively. In the Delaware Basin, there are drilling obligations or continuous drilling clauses associated with the majority of our acreage. While we believe that our current Delaware Basin drilling plan should provide sufficient drilling to meet these obligations for the next few years, in the event that we do not meet the obligations for certain leases, we anticipate that we will make any necessary bonus extension payments, or we will seek to renew or, re-lease in order to retain the leases. However, the payments required to do so may be significant and we may not be successful in such efforts. In the Utica Shale, approximately 30 percent, 7 percent, and 11 percent of our undeveloped leaseholds are scheduled to expire during 2017, 2018 and 2019, respectively.

Drilling Activity

The following tables set forth a summary of our developmental and exploratory well drilling activity for the periods presented. There is no necessary correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells that were turned-in-line to sales and commenced production during the period, regardless of when drilling was initiated. In-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection as of the date shown. The in-process wells are a normal part of our activity. The Wattenberg Field activity is comprised of pad drilling operations where multiple wells are developed from the same well pad and because we operate multiple drilling rigs in the area, we expect to have in-process wells at any given time. Wells may be in-process for anywhere from days to several months. We expect that normal in-process inventory will also exist in the development of our Delaware Basin leasehold. No wells were classified as exploratory in any of the periods presented.

Gross Development Well Drilling Activity

	Year Ended December 31,								
	2016			2015			2014		
Operating Region/Area	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)
Wattenberg Field, operated wells	140	64	2	136	78	4	86	44	2
Wattenberg Field, non-operated wells	24	12	—	58	19	—	70	25	—
Delaware Basin	1	5	—	—	—	—	—	—	—
Utica Shale	5	—	—	4	5	—	8	4	1
Other (2)	—	—	—	—	—	—	4	—	—
Total gross development wells	170	81	2	198	102	4	168	73	3

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(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective wells.
(2) Includes activity in the Marcellus Shale crude oil and natural gas properties, which were divested in October 2014.

	Net Development Well Drilling Activity								
	Year Ended December 31,								
	2016			2015			2014		
Operating Region/Area	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)
Wattenberg Field, operated wells	109.7	52.7	1.7	110.8	54.6	2.7	75.8	36.5	1.7
Wattenberg Field, non-operated wells	5.0	2.8	—	9.3	4.3	—	14.9	6.3	—
Delaware Basin	1.0	4.8	—	—	—	—	—	—	—
Utica Shale	4.5	—	—	3.0	4.5	—	7.0	3.0	1.0
Other (2)	—	—	—	—	—	—	2.0	—	—
Total net development wells	120.2	60.3	1.7	123.1	63.4	2.7	99.7	45.8	2.7

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(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective wells.
(2) Includes activity in the Marcellus Shale crude oil and natural gas properties, which were divested in October 2014.

Title to Properties

We believe that we hold good and defensible leasehold title to substantially all of our crude oil and natural gas properties in accordance with standards generally accepted in the industry. A preliminary title examination is typically conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial curative work is performed, as necessary, with respect to discovered defects which we deem to be significant, in order to procure division order title opinions. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty, and other outstanding interests. The properties may also be subject to additional burdens, liens, or encumbrances customary in the industry, including items such as operating agreements, current taxes, development obligations under crude oil and natural gas leases, farm-out agreements, and other restrictions. We do not believe that any of these burdens will materially interfere with our use of the properties.

Substantially all of our crude oil and natural gas properties, excluding our share of properties held by the limited partnerships that we sponsor, have been mortgaged or pledged as security for our revolving credit facility. See the footnote titled *Long-Term Debt* to our consolidated financial statements included elsewhere in this report.

Facilities

We lease 73,000 square feet of office space in Denver, Colorado, which serves as our corporate office, through February 2023 and 47,000 square feet of office space in Evans, Colorado through November 2025. We own a 32,000 square foot administrative office building located in Bridgeport, West Virginia, and a 60,000 square foot field operating facility in Greeley, Colorado.

We own or lease field operating facilities in or near Evans, Colorado, Midland, Texas, and Marietta, Ohio.

Governmental Regulation

While the prices of crude oil and natural gas are market driven, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for crude oil and natural gas production depends on several factors that are beyond our control. These factors include, but are not limited to, regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of crude oil and natural gas available for sale, the availability of adequate pipeline and other transportation, and processing facilities and the marketing of competitive fuels. In general, state and federal regulations are intended to protect consumers from unfair treatment and undue control, reduce environmental and health risks from the development and transportation of crude oil and natural gas, prevent misuse of crude oil and natural gas, and protect rights among owners in a common reservoir. Pipelines are subject to the jurisdiction of various federal, state, and local agencies. We believe that we are in compliance with such statutes, rules, regulations, and governmental orders in all material respects, although there can be no assurance that this is or will remain the case. The following summary discussion of the regulation of the U.S. oil and gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations, and environmental directives to which our operations may be subject.

Regulation of Crude Oil and Natural Gas Exploration and Production. Our exploration and production business is subject to various federal, state, and local laws and regulations relating to the taxation of crude oil and natural gas, the development, production, and marketing of crude oil, and natural gas and environmental and safety matters. State and local laws and regulations require drilling permits and govern the spacing and density of wells, rates of production, water discharge, prevention of waste, and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies where the well being drilled is located. Additionally, other regulated matters include:

- bond requirements in order to drill or operate wells;
- well locations;
- drilling and casing methods;
- surface use and restoration of well properties;
- well plugging and abandoning;
- fluid disposal; and
- air emissions.

In addition, our drilling activities involve hydraulic fracturing, which may be subject to additional federal and state disclosure and regulatory requirements discussed in "Environmental Matters" below and in Item 1A, *Risk Factors*.

Our operations also are subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of lands and leases. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units, and therefore, more difficult to drill and develop our leases where we own less than 100 percent of the leases located within the proposed unit. State laws may establish maximum rates of production from crude oil and natural gas wells, may prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability of production. Leases covering state or federal lands often include additional regulations and conditions. The effect of these conservation laws and regulations may limit the amount of crude oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating, and abandoning our crude oil and natural gas wells and other facilities. These laws and regulations, and any others that are passed by the jurisdictions where we have production, can limit the total number of wells drilled or the allowable production from successful wells, which can limit our reserves. As a result, we are unable to predict the future cost or effect of complying with such regulations.

Regulation of Transportation of Natural Gas. We move natural gas through pipelines owned by other companies and sell natural gas to other companies that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA") and under the Natural Gas Policy Act of 1978, and, as such, rates and charges for the transportation of natural gas in interstate commerce, accounting, and the extension, enlargement or abandonment of jurisdictional facilities, among other things, are subject to regulation. Each natural gas pipeline company holds certificates of public convenience and necessity issued by FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each natural gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, which imposes safety requirements in the design, construction, operation, and maintenance of interstate natural gas transmission facilities. FERC regulations govern how interstate pipelines communicate and do business with their affiliates. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties. Interstate pipelines may not operate their pipeline systems to preferentially benefit their marketing affiliates.

Each interstate natural gas pipeline company establishes its rates primarily through FERC's rate-making process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure, and related income taxes; and
- volume throughput assumptions.

The availability, terms, and cost of transportation affect our natural gas sales. Competition among suppliers has greatly increased. Furthermore, gathering is exempt from regulation under the Natural Gas Act, thus allowing gatherers to charge unregulated rates. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

Additional proposals and proceedings that might affect the industry occur frequently in Congress, FERC, state commissions, state legislatures, and the courts. The industry historically has been very heavily regulated and there is no assurance that the current regulatory approach recently taken by FERC and Congress will continue. We cannot determine to what extent our future operations and earnings will be affected by new legislation, new regulations, or changes in existing regulation, at federal, state or local levels.

Environmental Matters

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public demand for the protection of the environment has increased dramatically in recent years. The trend towards more expansive environmental legislation and regulations is expected to continue. To the extent laws are enacted or other governmental actions are taken which restrict drilling or impose environmental protection requirements resulting in increased costs, our business and prospects may be adversely affected. In addition, the change in the administration under the Executive Branch of our federal government may result in change or uncertainty with respect to the future regulatory environment affecting the oil and natural gas industry. This uncertainty may affect how our industry is regulated as well as the level of public interest in environmental protection and may result in new or different pressures being exerted. For example, public interest groups may increase their use of litigation as a means to continue to exert pressure on the oil and natural gas industry. Accordingly, while we expect regulatory and enforcement pressures on our business to continue at federal, state, and local levels, the nature, level, and source of such pressures may change.

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have adopted requirements that limit the approved disposal methods for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore may subject us to more rigorous and costly operating and disposal requirements.

Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We routinely apply hydraulic fracturing in our crude oil and natural gas production programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the crude oil or natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain fracturing activities involving diesel fuel under the federal Safe Drinking Water Act ("SDWA") and issued draft guidance related to this asserted regulatory authority in February 2014. The guidance explains the EPA's interpretation of the term “diesel fuel” for permitting purposes, describes existing Underground Injection Control Class II program requirements for permitting underground injection of diesel fuels in hydraulic fracturing and also provides recommendations for EPA permit writers in implementing these requirements. From time to time, Congress has considered legislation that would provide for broader federal regulation of hydraulic fracturing and disclosure of the chemicals used in the hydraulic fracturing process.

The White House Council on Environmental Quality continues to coordinate an administration-wide review of hydraulic fracturing. The EPA released the final report "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources" on December 12, 2016. The report concluded that activities involved in hydraulic fracturing can have impacts on drinking water under certain circumstances - including surface spills, injection of fluids into wells with inadequate integrity, discharge of untreated or inadequately treated wastewater, and disposal or storage in unlined pits. In addition, the U.S. Department of Energy has investigated practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These ongoing studies, depending on their degree of development and nature of results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. The U.S. Department of the Interior, through the Bureau of Land Management (the “BLM”), also finalized a rule in 2015 requiring the disclosure of chemicals used, mandating well integrity measures, and imposing other requirements relating to hydraulic fracturing on federal lands. The rule is currently stayed and not effective pending ongoing litigation.

The states in which we operate, Colorado, Texas, and Ohio, have adopted regulations regarding permitting, transparency, and well construction requirements with respect to hydraulic fracturing operations, and disposal well rules focused on potential seismicity concerns and may in the future adopt additional regulations or otherwise seek to ban fracturing or disposal activities altogether. Colorado and Texas require that all chemicals used in the hydraulic fracturing of a well be reported in a publicly searchable registry website developed and maintained by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission ("Frac Focus"). The Colorado rules also require operators seeking new location approvals to provide certain information to surface owners and adjacent property owners within 500 feet of a new well. Similarly, Colorado has implemented a baseline groundwater sampling rule, a rule governing setback distances of oil and gas wells located near population centers, and recently adopted new rules governing the development of large-scale facilities in urban mitigation areas and additional municipality notice requirements. In December 2013, the Colorado Oil and Gas Conservation Commission ("COGCC") issued new, more restrictive rules regarding spill reporting and remediation. In addition, during 2014, the Colorado Oil and Gas Conservation Act was amended to increase the potential sanctions for violating the Act or its implementing regulations, orders, or permits.

In November 2013, the Ohio Department of Natural Resources ("ODNR") proposed draft regulations pertaining to well pad construction requirements and increased bonding for construction, and these regulations were finalized in 2014. In October 2015, the ODNR proposed draft regulations pertaining to incident notification. A final hearing on these rules was held October 18, 2016 and the final draft rule was published on October 28, 2016. The effective date is not yet known. Additionally, in November 2015, the ODNR Assistant Chief announced draft rules in progress that address waste management, waste classification, secondary containment, emergency reporting, site remediation standards, well spacing, and simultaneous operations. We continue to be an active participant in the rule making process in Ohio.

In Colorado and Texas, local governing bodies have issued drilling moratoriums, develop jurisdictional siting, permitting and operating requirements, and conduct air quality studies to identify potential public health impacts. For instance, in 2013, the City of Fort Collins, Colorado, adopted a ban on drilling and fracturing of new wells within city limits. In the November 2013 election, voters in the Colorado cities of Boulder, Lafayette, Fort Collins and Brighton passed hydraulic fracturing bans, and in November 2014, Denton, Texas passed a hydraulic fracturing ban. See Item 1A, *Risk Factors*, for a more detailed discussion of these bans and relevant court decisions. If new laws or regulations that significantly restrict hydraulic fracturing or well locations continue to be adopted at local levels or are adopted at the state level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of hydrocarbons, may preclude our ability to drill wells. If hydraulic fracturing becomes more heavily regulated as a result of federal or state legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and permitting delays, as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that we are ultimately able to produce from our reserves. We continue to be active in stakeholder and interest groups and to engage with regulatory agencies in an open, proactive dialogue regarding these matters.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have generally utilized good operating and waste disposal practices, and when necessary, appropriate remediation techniques, prior owners and operators of these properties may not have utilized similar practices and techniques and hydrocarbons or other wastes may have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, we may be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), remediate property contamination (including surface and groundwater contamination), or perform remedial plugging operations to prevent future contamination.

CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of, transported, or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Under state laws, 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. As an owner and operator of crude oil and natural gas wells, we may be liable pursuant to CERCLA and similar state laws.

Our operations are subject to the federal Clean Air Act ("CAA") and comparable state and local requirements. The CAA contains provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states continue to develop regulations to implement these requirements. We may be required to incur certain capital investments in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Greenhouse gas record keeping and reporting requirements of the CAA became effective in 2011 and will continue into the future with increased costs for administration and implementation of controls. Federal New Source Performance Standards regarding oil and gas operations and amendments to such standards ("NSPS OOOO” and “NSPS OOOOa”) became effective between 2012 and 2016, and have added administrative and operational costs. In addition, Colorado adopted new regulations to meet the requirements of NSPS OOOO and promulgated significant new rules in February 2014 relating specifically to crude oil and natural gas operations that are equally or more stringent than NSPS OOOO / NPS OOOOa and directly regulate methane emissions from affected facilities. In April 2014, the Ohio Environmental Protection Agency Division of Air Pollution Control adopted new General Permit requirements for High Volume Horizontal Hydraulic Fracturing, Oil and Gas Well Site Production Operations. In October 2015, the EPA reduced the ozone compliance levels under the National Ambient Air Quality Standards (“NAAQS”) for ground level ozone to 70 parts per billion (“ppb”) from 75 ppb. In addition, the EPA extended the ozone monitoring season for 32 states, including Colorado, Texas, and Ohio. In October 2016, Colorado submitted revisions to its ozone SIP to meet requirements caused by an increase in ozone non-attainment status to “moderate” from “marginal.”

The federal Clean Water Act ("CWA") and analogous state laws impose strict controls against the discharge of pollutants and fill material, including spills and leaks of crude oil and other substances. The CWA also requires approval and/or permits prior to construction, where construction will disturb wetlands or other waters of the U.S. The CWA also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control, and Countermeasure ("SPCC") requirements of the CWA require appropriate secondary containment load out controls, piping controls, berms, and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture, or leak. The EPA and U.S. Army Corps of Engineers released a Connectivity Report in September 2013 which determined that the vast majority of tributary streams, wetlands, open water in floodplains, and riparian areas are connected. This report supported the final rule issued in June 2015 clarifying the scope of jurisdictional Waters of the U.S. This final rule has been stayed pending the resolution of ongoing litigation.

The Endangered Species Act (“ESA”) restricts activities that may affect endangered or threatened species or their habitats. Some of our operations may be located in areas that are or may be designated as habitats for endangered or threatened species. The U.S. Fish and Wildlife Service in 2016 finalized a rule to alter how it identifies critical habitat for endangered and threatened species.

Crude oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of crude oil spills. In addition to SPCC requirements, the Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from crude oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Historically, we have not experienced any significant crude oil discharge or crude oil spill problems. Our shift in production since mid-2010 to a greater percentage of crude oil increases our risks related to soil and water contamination from any future oil spills.

Our costs relating to protecting the environment have risen over the past few years and are expected to continue to rise in 2017 and beyond. Environmental regulations have increased our costs and planning time, but have had no materially adverse effect on our ability to operate to date. However, no assurance can be given that environmental regulations or interpretations of such regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations. See the footnote titled *Commitments and Contingencies* to our consolidated financial statements included elsewhere in this report.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including, but not limited to, the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures, and discharges of crude oil and natural gas. The occurrence of any of these events could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation, and penalties and suspension of operations. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the industry. These hazards include damage to wells, pipelines and other related equipment, damage to property caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution, and suspension of operations. In 2013, we experienced a significant rainfall event that created widespread flooding in our Wattenberg Field operations in Weld County, Colorado, which resulted in a shut-in of approximately 200 vertical wells. We incurred significant costs to replace damaged well equipment and to bring these vertical wells back on-line. In 2014 and 2015, we experienced three mechanical failures during drilling that resulted in the discharge of oil and related material, the effects from which have been remediated. The impact from the mechanical failures did not have a material adverse effect on our financial condition or results of operations.

Among the regulatory developments involving operating hazards that could impact us going forward are recent investigations by the U.S. Occupational Health and Safety Administration ("OSHA") and other governmental authorities regarding potential worker exposure to hydrocarbon vapors from certain petroleum transfer and related tasks. While we have not experienced such an event, several recent worker fatalities at oil and gas facilities nationwide are being reviewed by OSHA and other governmental authorities for a potential link to hydrocarbon vapor exposure. Regulatory requirements generally relating to worker exposure to hydrocarbon vapors could be increased or receive heightened scrutiny going forward.

Any significant problems related to our facilities could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify our purchase or will be available at all. Furthermore, we are not insured against our economic losses resulting from damage or destruction to third-party property, such as transportation pipelines, crude oil refineries, or natural gas processing facilities. Such an event could result in significantly lower regional prices or our inability to deliver our production.

Competition and Technological Changes

We believe that our production, exploration and drilling capabilities, and the experience of our management and professional staff, enable us to compete effectively in our industry. We encounter competition from numerous other crude oil and natural gas companies, drilling and income programs, and partnerships in all areas of operations, including drilling and marketing crude oil and natural gas, obtaining desirable crude oil and natural gas leases on producing properties, obtaining drilling, pumping and other services, attracting and retaining qualified employees, and obtaining capital. International developments may influence other companies to increase their domestic crude oil and natural gas exploration. Competition among companies for favorable prospects can be expected to continue and it is anticipated that the cost of acquiring properties will increase in the future. Many of our competitors possess larger staffs and greater financial resources than we do, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. Our ability to acquire additional properties and to explore for crude oil and natural gas prospects in the future depends upon our ability to conduct our operations, evaluate and select suitable properties, and consummate transactions in this highly competitive environment. We also face intense competition in other aspects of our business, including the marketing of natural gas from competitors including other producers and marketing companies.

The oil and gas industry is characterized by rapid and significant technological advancements and introduction of new products and services using new technologies. If one or more of the technologies we use now or in the future become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, results of operations, and cash flows could be materially adversely affected.

Employees

As of December 31, 2016, we had 395 full-time employees. Our employees are not covered by collective bargaining agreements. We consider relations with our employees to be good.

WHERE YOU CAN FIND ADDITIONAL INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.pdce.com. You may also read or copy any document we file at the SEC's public reference room in Washington, D.C., located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the public reference room. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact PDC Energy, Inc., Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call (800) 624-3821.

We recommend that you view our website for additional information, as we routinely post information that we believe is important for investors. Our website can be used to access such information as our recent news releases, committee charters, code of business conduct and ethics, stockholder communication policy, director nomination procedures, and our whistle blower hotline. While we recommend that you view our website, the information available on our website is not part of this report and is not incorporated by reference.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results, and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

Risks Relating to Our Business and the Industry

Crude oil, natural gas, and NGL prices fluctuate and declines in these prices, or an extended period of low prices, can significantly affect the value of our assets and our financial results and impede our growth.

Our revenue, profitability, cash flows and liquidity depend in large part upon the prices we receive for our crude oil, natural gas, and NGLs. Changes in prices affect many aspects of our business, including:

- our revenue, profitability and cash flows;
- our liquidity;
- the quantity and present value of our reserves;
- the borrowing base under our revolving credit facility and access to other sources of capital; and
- the nature and scale of our operations.

The markets for crude oil, natural gas, and NGLs are often volatile, and prices may fluctuate in response to, among other things:

- relatively minor changes in regional, national, or global supply and demand;
- regional, national, or global economic conditions, and perceived trends in those conditions;
- geopolitical factors, such as events that may reduce or increase production from particular oil-producing regions and/or from members of the Organization of Petroleum Exporting Countries, or OPEC; and
- regulatory changes.

The price of oil has been volatile since mid-2014, with a high over $100 per barrel in June 2014 to lows below $30 per barrel in 2016, in each case based on WTI prices, due to a combination of factors including increased U.S. supply, global economic concerns, and the resumption of oil exports from Iran. Prices for natural gas and NGLs have experienced similar volatility. Declines in prices adversely affect, among other things, our revenue and reserves, and have contributed to the recognition of impairment charges, including charges of $158.3 million and $150.3 million to write-down our Utica Shale producing and non-producing crude oil and natural gas properties to their estimated fair value in 2014 and 2015, respectively. Any future extended period of lower oil prices, or additional price declines, will have further adverse effects on us. For example, if we reduce our capital expenditures due to low prices, natural declines in production from our wells will likely result in reduced production and therefore reduced cash flow from operations, which would in turn further limit our ability to make the capital expenditures necessary to replace our reserves and production.

In addition to factors affecting the price of crude oil, natural gas, and NGLs generally, the prices we receive for our production are affected by factors specific to us and to the local markets where the production occurs. The prices that we receive for our production are generally lower than the relevant benchmark prices that are used for calculating commodity derivative positions. These differences, or differentials, are difficult to predict and may widen or narrow in the future based on market forces. Differentials can be influenced by, among other things, local or regional supply and demand factors and the terms of our sales contracts. Over the longer term, differentials will be significantly affected by factors such as investment decisions made by providers of midstream facilities and services, refineries and other industry participants, and the overall regulatory and economic climate. For example, increases in U.S. domestic oil production generally may result in widening differentials, particularly for production from some basins. We may be materially and adversely impacted by widening differentials on our production.

The Delaware Basin acquisitions may not achieve their intended results and may result in us assuming unanticipated liabilities.

The Delaware Basin acquisitions subject us to many of the risks described below in “Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.” For example, we may discover title defects or adverse environmental or other conditions relating to the properties acquired in the transactions of which we are currently unaware. Environmental, title, and other problems could reduce the value of the properties to us, and, depending on the circumstances, we could have limited or no recourse to the sellers with respect to those problems. We have assumed substantially all of the liabilities associated with the acquired properties and would be entitled to indemnification in connection with those liabilities in only limited circumstances, for limited periods and in limited amounts. We cannot provide assurance that such potential remedies will be adequate for any liabilities we incur, and such liabilities could be significant. Also, it is uncertain whether our existing operations and the acquired properties and assets can be integrated in an efficient and effective manner. In addition, the success of the Delaware Basin acquisitions depend on, among other things, the accuracy of our assessment of the reserves and drilling locations associated with the acquired properties, future oil, NGL and natural gas prices and operating costs, and various other factors. The majority of the value was attributed to unproved leaseholds, which inherently have a higher risk of uncertainty than the acquisition of proved developed reserves. These assessments were based to a significant degree on information provided by the sellers and we cannot guarantee their accuracy. Although the acquired properties are subject to many of the risks and uncertainties to which acquisitions we pursue are subject generally, risks associated with the Delaware Basin acquisitions in particular include those associated with our ability to operate efficiently in a new area, the significant size of the transactions in the aggregate, the fact that a substantial majority of the acquired properties are undeveloped, and the additional indebtedness and transaction costs we incurred in connection with the acquisitions. Many of these risks also apply to acquisitions of additional Delaware Basin properties we have pursued or may pursue in the future. In addition, we expect that pursuing our future development plans for the properties will require capital in excess of our projected cash flow from operations for some period of time beginning in 2017, which may increase our need for external financing.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business. These risks are greater at times and in areas where the pace of our exploration and development activity slows. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals, approvals of the Texas General Land Office for our Delaware Basin properties, and other factors. These risks are currently greater for us in the Delaware Basin area than in our other operating areas. As of December 31, 2016, approximately 30 percent of our total net acreage in the Delaware Basin was held-by-production or drilling operations. In addition, a substantial portion of our Utica Shale acreage is held-by-production by a third party operator’s shallow vertical wells. Our relative lack of control over this acreage increases the risk that some of our leases will expire.

Ballot initiatives have been proposed in Colorado from time to time that could vastly expand the right of local governments to limit or prohibit oil and natural gas production and development in their jurisdictions and could impose additional regulations on production and development activities. If any initiative or legislation of this nature is implemented and survives legal challenge, additional limitations or prohibitions could be placed on crude oil, natural gas and NGL production and development within certain areas of Colorado or the state as a whole. Similar initiatives could be proposed in other states.

During 2016, certain interest groups in Colorado opposed to oil and natural gas development generally, or hydraulic fracturing in particular, advanced various options for ballot initiatives aimed at significantly limiting or effectively preventing oil and natural gas development in the state of Colorado. Proponents of two such initiatives attempted to qualify the initiatives to appear on the ballot for the November 2016 election. On August 29, 2016, the Colorado Secretary of State issued a press release and statements of insufficiency of signatures, stating that the proponents of the proposals had failed to collect enough valid signatures to have the proposals included on the ballot.

One of the initiatives, which we refer to as the “local control” initiative, would have amended the state constitution to give city, town, and county governments the right to regulate, or to ban, oil and gas development and production within their boundaries, notwithstanding rules and approvals to the contrary at the state level. This proposal was motivated in part by a decision of the Colorado Supreme Court holding that local government restrictions on oil and gas activities are subject to preemption by state rules.

A second initiative, which we refer to as the “setback” initiative, would have amended the state constitution to require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or broadly defined “area of special concern,” including public and community drinking water sources, lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, riparian areas, playgrounds, permanent sports fields, amphitheaters, public parks, and public open space.

If implemented, the setback initiative would have effectively prohibited the vast majority of our planned future drilling activities in Colorado and would therefore have made it impossible to pursue our current development plans. The local control proposal would potentially have had a similar effect, depending on the nature and extent of regulations implemented by relevant local governmental authorities. Pursuant to the determination of the Colorado Secretary of State, these proposals did not appear on the November 2016 ballot. However, future proposals of this nature are possible.

Because a substantial portion of our operations and reserves are located in Colorado, the risks we face with respect to such future proposals are greater than those of our competitors with more geographically diverse operations. Although we cannot predict the outcome of future ballot initiatives, statutes, or regulatory developments, such developments could materially impact our results of operations, production, and reserves.

A substantial part of our crude oil, natural gas, and NGLs production is located in the Wattenberg Field, making us vulnerable to risks associated with operating primarily in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing formations.

Although we have significant non-producing leasehold positions in the Delaware Basin in Texas and the Utica Shale in Ohio, our current production is primarily located in the Wattenberg Field in Colorado. Because our production is not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including:

- fluctuations in prices of crude oil, natural gas, and NGLs produced from the wells in the area;
- natural disasters such as the flooding that occurred in Northern Colorado in September 2013;
- restrictive governmental regulations; and
- curtailment of production or interruption in the availability of gathering, processing, or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells.

For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that could adversely affect development activities or production relating to those formations. Such an event could have a material adverse effect on our results of operations and financial condition. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field and the Delaware Basin, the demand for, and cost of, drilling rigs, equipment, supplies, personnel, and oilfield services increase. Shortages or the high cost of drilling rigs, equipment, supplies, personnel, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition or results of operations.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from drilling wells.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Utica Shale area are particularly vulnerable to title deficiencies due the long history of land ownership in the area and correspondingly extensive and complex chains of title. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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

Our industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil, natural gas, and NGL reserves. To date, we have financed capital expenditures primarily with bank borrowings under our revolving credit facility, cash generated by operations and proceeds from capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

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

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources could increase, and there can be no assurance that such other sources of capital would be available at that time on reasonable terms or at all. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

Our ability to produce crude oil, natural gas, and NGLs could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our operations could be adversely impacted if we are unable to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations. Currently, the quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations governing usage may lead to water constraints and supply concerns (particularly in some parts of the country). In addition, both eastern Colorado and western Texas have relatively arid climates and experience drought conditions from time to time. As a result, future availability of water from certain sources used in the past may become limited.

The imposition of new environmental initiatives relating to wastewater could restrict our ability to conduct certain operations such as hydraulic fracturing. This includes potential restrictions on waste disposal, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of hydrocarbons. For example, in 2010 a petition was filed by the Natural Resources Defense Council with the EPA requesting that the agency reassess its prior and long-standing determination that certain oil and natural gas exploration and production wastes would not be regulated as hazardous waste under Subtitle C of the RCRA. The EPA has not yet acted on the petition and it remains pending. In a separate but related matter, a proposed consent decree filed in December 2016 between the EPA and several environmental groups commits the EPA to decide whether to revise its RCRA Subtitle D criteria regulations and state plan guidelines for the oil and natural gas sector by March 2019. If the EPA began treating some or all of these wastes as “hazardous” under Subtitle C in response to the petition or as a result of the proposed consent decree, the consequences for our operations would be serious, and would include a significant increase in costs associated with waste treatment and disposal and a potential inability to conduct operations in some instances.

The CWA and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas waste, into navigable waters or other regulated federal and state waters. Permits or other approvals must be obtained to discharge fill and pollutants into regulated waters and to conduct construction activities in such waters and wetlands. Uncertainty regarding regulatory jurisdiction over wetlands and other regulated waters of the United States has complicated, and will continue to complicate and increase the cost of, obtaining such permits or other approvals. In June 2015, the EPA and the U.S. Army Corps of Engineers issued a final rule that clarifies the scope of the agencies' jurisdiction under section 404 of the CWA to regulate certain activities occurring in waters of the United States. This rule, known as the Clean Water Rule, has been challenged by various parties in multiple federal courts, and as a result of this litigation is currently stayed and not yet effective. An expansive definition of such jurisdictional waters could affect our ability to operate in certain areas, increase costs of operations, and cause significant scrutiny and delays in permitting. While generally exempt under federal programs, many state agencies have also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. These permits, in turn, impose far-ranging monitoring, flow control, and other obligations that have generated, and will continue to generate, increased costs for our operations.

In June 2016, the EPA finalized pretreatment standards for indirect discharges of wastewater from the oil and gas extraction industry. The regulation prohibits sending wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. Some states, including Pennsylvania, have banned the treatment of fracturing wastewater at publicly owned treatment facilities. There also has been recent nationwide concern, particularly in Ohio and Oklahoma, over earthquakes associated with Class II underground injection control wells, a predominant storage method for crude oil and gas wastewater. As seen in Ohio, it is likely that new rules and regulations will be developed to address these concerns, possibly eliminating access to Class II wells in certain locations, and increasing the cost of disposal in others.

Finally, the EPA study on hydraulic fracturing noted above focused on various stages of water use in hydraulic fracturing operations. It is possible that the EPA will move to more strictly regulate the use of water in hydraulic fracturing operations. While we cannot predict the impact that these changes may have on our business at this time, they may be material to our business, financial condition, and operations. In addition, an inability to meet our water supply needs to conduct our completion operations may adversely impact our business.

The marketability of our production is dependent upon transportation and processing facilities the capacity and operation of which we do not control. Market conditions or operational impediments, including high line pressures, particularly in the Wattenberg Field, and other impediments affecting midstream facilities and services, could hinder our access to crude oil, natural gas, and NGL markets, increase our costs or delay production, and thereby adversely affect our profitability.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations will be adversely affected. For example, in some recent periods, due to ongoing drilling activities by us and third parties and hot temperatures during the summer months, the principal third-party provider we use in the Wattenberg Field area for midstream facilities and services experienced increased gathering system pressures during those warmer months. The resulting capacity constraints reduced the productivity of some of our older vertical wells and limited incremental production from some of our newer horizontal wells. This constrained our production and reduced our revenue from the affected wells. Capacity constraints affecting natural gas production also impacted the associated NGLs. Some operators in the Delaware Basin have experienced similar issues from time to time, in part due to significant increases in production in the area. Our operations in Texas and elsewhere may be adversely affected by those issues. The use of alternative forms of transportation for oil production such as trucks or rail involve risks, including the risk that increased regulation could lead to increased costs or shortages of trucks or railcars.

In addition to causing production curtailments, capacity constraints can also reduce the price we receive for the crude oil, natural gas, and NGLs we produce.

We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks. For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities; and
- Some upstream energy companies have in the recent past sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure.

Like other producers we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If we reduce the pace of our drilling activities significantly after entering into such commitments for any reason, it may be difficult or impossible for us to satisfy those commitments.

Reduced commodity prices could result in significant impairment charges and significant downward revisions of proved reserves.

Crude oil prices fell dramatically in the second half of 2014, with further declines in 2015 and into 2016, and the domestic natural gas market remains weak. Low commodity prices could result in, among other adverse effects, significant impairment charges. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date that the estimate of future cash flows for each producing basin is calculated. However, a significant decrease in long-term forward prices alone could result in a significant impairment for our properties that are sensitive to declines in prices. We have incurred impairment charges in a number of recent periods, including charges of $150.3 million and $158.3 million relating to our Utica Shale properties in 2015 and 2014, respectively. Similar charges could occur in the future. In addition, low commodity prices could result in significant downward revisions to the estimated quantity and value of our proved reserves.

Our estimated crude oil and natural gas reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

Calculating reserves for crude oil, natural gas, and NGLs requires subjective estimates of remaining volumes of underground accumulations of hydrocarbons. Assumptions are also made concerning commodity prices, production levels, and operating and development costs over the economic life of the properties. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. Independent petroleum engineers prepare our estimates of crude oil, natural gas, and NGLs reserves using pricing, production, cost, tax and other information that we provide. The reserve estimates are based on certain assumptions regarding commodity prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual results could greatly affect:

- the economically recoverable quantities of crude oil, natural gas, and NGLs attributable to any particular group of properties;
- future depreciation, depletion, and amortization ("DD&A") rates and amounts;
- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of future net cash flows;
- timing of our capital expenditures; and
- the amount of funds available for us to borrow under our revolving credit facility.

Some of our reserve estimates must be made with limited production histories, which renders these reserve estimates less reliable than estimates based on longer production histories. Horizontal drilling in the Wattenberg Field is a relatively recent development, whereas vertical drilling has been used by producers in this field for over 40 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small, and future reserve estimates will be affected by additional production data as it becomes available. Horizontal drilling in the Utica Shale and the Delaware Basin has an even more limited history. Further, reserve estimates are based on the volumes of crude oil, natural gas, and NGLs that are anticipated to be economically recoverable from a given date forward based on economic conditions that exist at that date. The actual quantities of crude oil, natural gas, and NGLs recovered will be different than the reserve estimates since they will not be produced under the same economic conditions as used for the reserve calculations. In addition, quantities of probable and possible reserves by definition are inherently more risky than proved reserves, in part because they have greater uncertainty associated with the recoverable quantities of hydrocarbons.

At December 31, 2016, approximately 71.2 percent of our estimated proved reserves were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $2.1 billion during the five years ending December 31, 2021, as estimated in the calculation of the standardized measure of oil and gas activity. The estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC's reserve reporting rules, PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of initial booking, and we may therefore be required to downgrade to probable or possible any PUDs that are not developed within this five-year time frame.

The present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated discounted future net cash flows from our proved reserves, and the estimated quantity of those reserves, were based on the prior year's first day of the month 12-month average crude oil and natural gas index prices. However, factors such as actual prices we receive for crude oil and natural gas and hedging instruments, the amount and timing of actual production, the amount and timing of future development costs, the supply of and demand for crude oil, natural gas, and NGLs, and changes in governmental regulations or taxation, also affect our actual future net cash flows from our properties. The timing of both our production and incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor (the rate required by the SEC) we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our properties or the industry in general.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations. We may not be able to develop our identified drilling locations as planned.

Producing crude oil, natural gas, and NGL reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline may change over time and may exceed our estimates. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover, or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

We have identified a number of well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including:

- crude oil, natural gas, and NGL prices;
- the availability and cost of capital;
- drilling and production costs;
- availability of drilling services and equipment;
- drilling results;
- lease expirations;
- midstream constraints;
- access to and availability of water sourcing and distribution systems;
- regulatory approvals; and
- other factors.

Because of these factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce crude oil, natural gas, or NGLs from these or any other potential well locations. In addition, the number of drilling locations available to us will depend in part on the spacing of wells in our operating areas. An increase in well density in an area could result in additional locations in that area, but a reduced production performance from the area on a per-well basis. Further, certain of the horizontal wells we intend to drill in the future may require pooling of our lease interests with the interests of third parties. Some states, including Colorado, allow the involuntary pooling of tracts in a relatively broad number of circumstances in order to facilitate exploration. Other states, including Texas, restrict involuntary pooling to a narrower set of circumstances and consequently these states rely primarily on voluntary pooling of lands and leases. In states where pooling is accomplished primarily on a voluntary basis, it may be more difficult to form units and, therefore, more difficult to fully develop a project if we own less than 100 percent of the leasehold or one or more of our leases does not provide the necessary pooling authority. If third parties are unwilling to pool their interests with ours, we may be unable to require such pooling on a timely basis or at all, and this would limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified. Further, our inventory of drilling projects includes locations in addition to those that we currently classify as proved, probable, and possible. The development of and results from these additional projects are more uncertain than those relating to probable and possible locations, and significantly more uncertain than those relating to proved locations. We have generally accelerated the pace of our development activities in the Wattenberg Field over the past several years, and this has reduced our related inventory of drilling locations.

The wells we drill may not yield crude oil, natural gas, or NGLs in commercially viable quantities and productive wells may be less successful than we expect.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of hydrocarbon-bearing rocks. However, our geologists cannot know conclusively prior to drilling and testing whether crude oil, natural gas, or NGLs will be present in sufficient quantities to repay drilling or completion costs and generate a profit given the available data and technology. Furthermore, even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques do not enable our geologists to be certain as to whether hydrocarbons are, in fact, present in those structures or the quantity of the hydrocarbons. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures, which may result in a reduction in our returns or losses. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. If a well is determined to be dry or uneconomic, which can occur even though it contains some crude oil, natural gas, or NGLs, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging, and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient crude oil, natural gas, and NGLs to be profitable, or they may be less productive and/or profitable than we expected. In recent years we have been able to achieve reductions in drilling and completion costs in connection with lower commodity prices. However, as commodity prices have stabilized or increased since mid-2016, many of these costs have begun to increase, and further increases are expected. If we drill a dry hole or unprofitable well on a current or future prospect, or if drilling or completion costs increase, the profitability of our operations will decline and the value of our properties will likely be reduced. Exploratory drilling is typically subject to substantially greater risk than development drilling. In addition, initial results from a well are not necessarily indicative of its performance over a longer period.

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

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling can be unprofitable, not only due to dry holes, but also due to curtailments, delays, or cancellations as a result of other factors, including:

- unusual or unexpected geological formations;
- pressures;
- fires;
- floods;
- loss of well control;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delays in the delivery of equipment and services;
- unanticipated environmental liabilities;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells, and regulatory penalties. For example, a loss of containment of hydrocarbons during drilling activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including for environmental remediation, depending upon the circumstances of the loss of containment, the nature and scope of the loss and the applicable laws and regulations. We maintain insurance against various losses and liabilities arising from our operations; however, insurance against certain operational risks may not be available or may be prohibitively expensive relative to the perceived risks presented. For example, we may not have coverage with respect to a pollution event if we are unaware of the event while it is occurring and are therefore unable to report the occurrence of the event to our insurance company within the time frame required under our insurance policy. Thus, losses could occur for uninsurable or uninsured risks or for amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance and/or governmental or third party responses to an event could have a material adverse effect on our business activities, financial condition and results of operations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites.

Our business strategy focuses on production in our liquid-rich shale plays. In this regard, we plan to allocate our capital to an active horizontal drilling program. Prior to 2012, most of the wells we drilled were vertical wells. Since 2012, however, we have devoted the majority of our capital budget to drilling horizontal wells. Drilling horizontal wells is technologically more difficult than drilling vertical wells - including as a result of risks relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore - and the risk of failure is therefore greater than the risk involved in drilling vertical wells. Additionally, drilling a horizontal well is typically far costlier than drilling a vertical well. This means that the risks of our drilling program will be spread over a smaller number of wells, and that, in order to be economic, each horizontal well will need to produce at a higher level in order to cover the higher drilling costs. Similarly, the average lateral length of the horizontal wells we drill has generally been increasing. Longer-lateral wells are typically more expensive and require more time for preparation and permitting. In addition, we have transitioned to the use of multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we will be better served by drilling horizontal wells using multi-well pads, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

Under the "successful efforts" accounting method that we use, unsuccessful exploratory wells must be expensed in the period when they are determined to be non-productive, which reduces our net income in such periods and could have a negative effect on our profitability.

We conduct exploratory drilling in order to identify additional opportunities for future development. Under the "successful efforts" method of accounting that we use, the cost of unsuccessful exploratory wells must be charged to expense in the period in which the wells are determined to be unsuccessful. In addition, lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast, unsuccessful development wells are capitalized as a part of the investment in the field where they are located. Because exploratory wells generally are more likely to be unsuccessful than development wells, we anticipate that some or all of our exploratory wells may not be productive. The costs of such unsuccessful exploratory wells could result in a significant reduction in our profitability in periods when the costs are required to be expensed.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness. As a result, a significant portion of our cash flows will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flows from operations, or have future borrowing capacity available, to enable us to repay our indebtedness or to fund other liquidity needs. We incurred a substantial amount of additional debt in order to finance part of the purchase price for the Delaware Basin acquisitions, and the properties acquired currently produce only modest amounts of cash flow from operations.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flows from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend on our future operating performance and financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic conditions, including possibly depressed commodity pricing, and financial, business and other factors, many of which are beyond our control. We expect that some commercial lenders may look to reduce their exposure to exploration and production companies due to regulatory pressures they face and/or independent business considerations. This could adversely affect our liquidity and our ability to refinance our debt.

A substantial decrease in our operating cash flows or an increase in our expenses could make it difficult for us to meet our debt service requirements and could require us to modify our operations, including by curtailing our exploration and drilling programs, selling assets, refinancing all or a portion of our existing debt, or obtaining additional financing. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of future debt agreements may, and our existing debt agreements do, restrict us from implementing some of these alternatives. In the absence of adequate cash from operations and other available capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate these dispositions for fair market value, in a timely manner or at all. Furthermore, any proceeds that we could realize from any dispositions may not be adequate to meet our debt service or other obligations then due. Because the cash required to service our indebtedness is not available to finance our operations and other business activities, our indebtedness limits our flexibility in planning for or reacting to changes in our business and the industry in which we operate and increases our vulnerability to economic downturns and sustained declines in commodity prices.

Covenants in our debt agreements currently impose, and future financing agreements may impose, significant operating and financial restrictions.

The indentures governing our senior notes and our revolving credit facility contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and certain of our subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem, or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit facility is secured by substantially all of our crude oil and natural gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The restrictions contained in our debt agreements may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility.

Our revolving credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

We depend in large part on our revolving credit facility for future capital needs. The terms of the credit agreement require us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility or other debt agreements could result in a default under those agreements, which could cause all of our existing indebtedness to be immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. Decreases in the price of crude oil, natural gas, or NGLs can be expected to have an adverse effect on the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our revolving credit facility could adversely affect our operations and our financial results.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there would be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on our indebtedness and satisfy our other obligations.

Any default under the agreements governing our indebtedness, including a default under our revolving credit facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal and interest on our indebtedness and satisfy our other obligations. If we are unable to generate sufficient cash flows and are otherwise unable to obtain the funds necessary to meet required payments of principal and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such a 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 revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. In addition, the default could result in a cross-default under other debt agreements. If our operating performance declines, we may in the future need to seek waivers from the required lenders under our revolving credit facility to avoid being in default and we may not be able to obtain such a waiver. If this occurs, we would be in default under our revolving credit facility, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. We cannot assure you that we will be granted waivers or amendments to our debt agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness and for other purposes would decrease.

Notwithstanding our current indebtedness levels and restrictive covenants, we may still be able to incur substantial additional debt, which could exacerbate the risks described above.

We may be able to incur additional debt in the future. Although our debt agreements contain restrictions on our ability to incur indebtedness, those restrictions are subject to a number of exceptions. In particular, we may borrow under the revolving credit facility, and may do so in 2017. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Adding new debt to current debt levels could intensify the related risks that we now face.

Seasonal weather conditions and lease stipulations can adversely affect our operations.

Seasonal weather conditions and lease stipulations designed to protect wildlife affect operations in some areas. In certain areas drilling and other activities may be restricted or prohibited by lease stipulations, or prevented by weather conditions, for significant periods of time. This limits our operations in those areas and can intensify competition during the active months for drilling rigs, oil field equipment, services, supplies, and qualified personnel, which may lead to additional or increased costs or periodic shortages. These constraints and the resulting high costs or shortages could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability. Similarly, hot weather during some recent periods adversely impacted the operation of certain midstream facilities, and therefore our production. Similar events could occur in the future and could negatively impact our results of operations and cash flows.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We operate approximately 88 percent of the wells in which we own an interest. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator’s timing and amount of capital expenditures, expertise (including safety and environmental compliance) and financial resources, inclusion of other participants in drilling wells, and use of technology. The failure by an operator to adequately perform operations, or an operator’s breach of the applicable agreements, could reduce production and revenues and adversely affect our profitability. These risks are heightened in some respects in periods of depressed commodity prices as operators may propose operations that we believe to be economically unattractive, leading us to incur non-consent penalties. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, production and related matters.

Our commodity derivative activities could result in financial losses or reduced income from failure to perform by our counterparties, could limit our potential gains from increases in prices and could result in volatility in our net income.

We use commodity derivatives for a portion of the production from our own wells and for natural gas purchases and sales by our marketing subsidiary to achieve more predictable cash flows, to reduce exposure to adverse fluctuations in commodity prices, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected or the counterparty to the commodity derivative contract defaults on its contractual obligations. In addition, many of our commodity derivative contracts are based on WTI or another oil or natural gas index price. The risk that the differential between the index price and the price we receive for the relevant production may change unexpectedly makes it more difficult to hedge effectively and increases the risk of a hedging-related loss.

Also, commodity derivative arrangements may limit the benefit we would otherwise receive from increases in the prices for the relevant commodity, and they may require the use of our resources to meet cash margin requirements.

In addition, at December 31, 2016, we had hedged a total of 13,342 MBbls of crude oil and 128,036 BBtu of natural gas for 2017 and 2018. These hedges may be inadequate to protect us from continuing and prolonged declines in oil and natural gas prices, and our current hedge position is smaller than it has been in recent years.

The estimated fair value of our aggregate commodity derivative position as of December 31, 2015, was an asset balance of approximately $263.8 million. As a result of factors including the settlement of commodity derivative positions over the course of 2016 and changes in commodity prices, the estimated fair value of our aggregate commodity derivative position as of December 31, 2016 was a liability balance of approximately $70.0 million. Accordingly, based on our current commodity derivative positions and current commodity prices, we expect that cash flow from our commodity derivative activities will be substantially lower in 2017 than it was in 2016, and may be negative.

Since we do not designate our commodity derivatives as cash flow hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of commodity derivatives are recorded in our income statements, and our net income is subject to greater volatility than it would be if our commodity derivative instruments qualified for hedge accounting. For instance, if commodity prices rise significantly, this could result in significant non-cash charges during the relevant period, which could have a material negative effect on our net income.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, natural gas, and NGLs sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our commodity derivatives as well as the commodity derivatives used by our marketing subsidiary expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition and profitability. We face similar risks with respect to our other counterparties, including the lenders under our revolving credit facility and the providers of our insurance coverage.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than 100 percent of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas, and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The occurrence of a significant accident or other event not fully covered by insurance or in excess of our insurance coverage could have a material adverse effect on our operations and financial condition. Insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. We also do not carry contingent business interruption insurance related to the purchasers of our production. In addition, pollution and environmental risks are generally not fully insurable.

We may not be able to keep pace with technological developments in our industry.

Our industry is characterized by rapid and significant technological advancements. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those or other new technologies at substantial cost. In addition, our competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Competition in our industry is intense, which may adversely affect our ability to succeed.

Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce crude oil, natural gas, and NGLs, but also carry on refining operations and market petroleum and other products on a regional, national, or worldwide basis. These companies may be able to pay more for productive properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies may have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors may also be able to absorb the burden of present and future federal, state, local, and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect the success of our operations and our profitability.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

A failure to complete successful acquisitions would limit our growth.

Because our crude oil and natural gas properties are depleting assets, our future reserves, production volumes, and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. In addition, we continue to strive to achieve greater efficiencies in our drilling program, and our ability to do so is dependent in part on our ability to complete land trades or exchanges and other acquisitions that allow us to increase our working interests in particular properties. Acquiring additional crude oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise is a significant component of our strategy. We may not be able to identify attractive acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. It may be difficult to agree on the economic terms of a transaction, as a potential seller may be unwilling to accept a price that we believe to be appropriately reflective of prevailing economic conditions. If we are unable to complete suitable acquisitions, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

Acquisitions of producing properties and undeveloped properties have been an important part of our growth over time. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues, and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we generally perform engineering, environmental, geological, and geophysical reviews of the acquired properties, which we believe are generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface, and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we often acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. Often we are not entitled to contractual indemnification associated with acquired properties. We often acquire interests in properties on an “as is” basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities, or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price, and any related increase in interest expense or other related charges.

Some of our acquisitions are structured as land trades or exchanges. These transactions may give rise to any or all of the foregoing risks. In addition, transactions of this type create a risk that we will undervalue the properties we transfer to the counterparty in the trade or exchange. Such an undervaluation would result in the transaction being less favorable to us than we expected.

The cost of defending any suits brought against us, and any judgments or settlements resulting from such suits, could have an adverse effect on our results of operations and financial condition.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, and personal injury or property damage matters, in the ordinary course of our business. For example, in recent years, we have been subject to lawsuits regarding royalty practices and payments and matters relating to certain of our affiliated partnerships. In addition in August 2015 we received a Clean Air Act Section 114 Information Request (the "Information Request")from the EPA, and this request could result in penalties or other liabilities. The outcome of pending legal proceedings is inherently uncertain. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, the resolution of such a proceeding could result in penalties or sanctions, settlement costs and/or judgments, consent decrees, or orders requiring a change in our business practices, any of which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties, sanctions or costs may be insufficient. Judgments and estimates to determine accruals or the anticipated range of potential losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.

The market price of our common stock is highly volatile, and we expect it to continue to be volatile for the foreseeable future. Adverse events could trigger declines in the price of our common stock, including, among others:

- changes in production volumes, worldwide demand and prices for crude oil and natural gas;
- changes in market prices of crude oil and natural gas;
- inability to hedge future production at the same pricing level as our current hedges;
- changes in securities analysts' estimates of our financial performance;
- fluctuations in stock market prices and volumes, particularly among securities of energy companies;
- changes in market valuations and valuation multiples of similar companies;
- changes in interest rates;
- announcements regarding adverse timing or lack of success in discovering, acquiring, developing, and producing crude oil and natural gas resources;
- announcements by us or our competitors of significant contracts, new acquisitions, discoveries, commercial relationships, joint ventures, or capital commitments;
- decreases in the amount of capital available to us, including as a result of borrowing base reductions and/or lenders ceasing to participate in our revolving credit facility syndicate;
- operating results that fall below market expectations or variations in our quarterly operating results;
- loss of a major customer;
- loss of a relationship with a partner;
- the identification of and severity of environmental events and governmental and other third-party responses to the events; or
- additions or departures of key personnel.

External events, such as news concerning economic conditions, counterparties to our natural gas or oil derivatives arrangements, changes in government regulations impacting the oil and natural gas exploration and production industries or the movement of capital into or out of our industry, are also likely to affect the price of our common stock, regardless of our operating performance. Similarly, our stock price could be adversely affected by changes in the way that analysts and investors assess the geological and economic characteristics of the basins in which we operate. For example, general market perceptions of the Permian Basin region have recently become highly favorable, and adverse changes in those perceptions could have a corresponding effect on the price of our stock. Furthermore, general market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could affect the price of our common stock. Recently, the stock markets have experienced price and volume volatility that has affected many companies' stock prices. Stock prices for many companies have experienced wide fluctuations that have often been unrelated to the operating performance of those companies. These fluctuations may affect the market price of our common stock.

In addition, a portion of the consideration we paid to the sellers in the Delaware Basin acquisitions was in the form our common stock. Those shares are currently subject to lock-up periods set forth in the applicable Investment Agreement. Upon the expiration of the lock-up period, the sellers will be entitled to sell their shares into the public markets, which could cause the market price of our common stock to decline.

Our business could be negatively impacted by security threats, including cybersecurity threats, and other disruptions.

We face various security threats, including attempts by third parties to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient in preventing them from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial condition, results of operations, or cash flows.

In particular, the oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling activities, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to store, transmit, process, and record sensitive information (including trade secrets, employee information, and financial and operating data), communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. The complexity of the technologies needed to explore for and develop oil, natural gas, and NGLs make certain information more attractive to thieves.

Our business partners, including vendors, service providers, operating partners, purchasers of our production, and financial institutions, are also dependent on digital technology. Some of these business partners may be provided limited access to our sensitive information or our information systems and related infrastructure. A vulnerability in the cybersecurity of one or more of our vendors could facilitate an attack on our systems.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and unintentional events, have also increased. A cyber-attack could include an attempt to gain unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption. "Phishing" and other types of attempts to obtain unauthorized information or access are often sophisticated and difficult to detect or defeat. Certain countries are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems and networks, and those of our business partners, may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, theft of property or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Given the politically sensitive nature of hydraulic fracturing and the controversy generated by its opponents, our technologies, systems and networks may be of particular interest to certain groups with political agendas, which may seek to launch cyber-attacks as a method of promoting their message. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any significant cyber-attacks, there can be no assurance that we will not be the target of such attacks in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any security vulnerabilities.

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

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of such GHGs are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources under the CAA’s Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. It was widely expected that facilities required to obtain PSD permits for their GHG emissions would be required to also reduce those emissions according to “best available control technology” (“BACT”) standards. In its permitting guidance for GHGs, issued in November 2010, the EPA recommended options for BACT from the largest sources, which include improved energy efficiency, among others. The EPA also issued a final rule in July 2013 retaining the “tailored” permitting thresholds, opting not to extend GHG permitting requirements to smaller stationary sources at that time.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued an opinion and order in *Coalition for Responsible Regulation v. Environmental Protection Agency,* upholding the EPA’s GHG-related rules against challenges from various state and industry group petitioners. In October 2013, the United States Supreme Court in *Utility Air Regulatory Group v. EPA*, accepted a petition for certiorari to decide whether the EPA correctly determined that its regulation of GHGs from mobile sources triggered permitting requirements under the CAA for stationary sources that emit GHGs. In June 2014, the Supreme Court upheld a portion of the EPA’s GHG stationary source program, but invalidated a portion of it. The Court held that stationary sources already subject to the PSD or Title V program for non-GHG criteria pollutants remained subject to GHG BACT requirements, but ruled that sources subject to the PSD or Title V program only for GHGs could not be forced to comply with GHG BACT requirements. Upon remand, the D.C. Circuit issued an amended judgment, which, among other things, vacated the PSD and Title V regulations under review in that case to the extent they require a stationary source to obtain a PSD or Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. In October 2016, the EPA issued a proposed rule to revise its PSD and Title V regulations applicable to GHGs in accordance with the decisions noted above, including proposing a *de minimis* level of GHG emissions below which BACT is not required. Depending on what the EPA does in a final rule, it is possible that any regulatory or permitting obligation that limits emissions of GHGs could extend to smaller stationary sources and require us to incur costs to reduce and monitor emissions of GHGs associated with our operations and also adversely affect demand for the crude oil and natural gas that we produce.

In the past, Congress has considered various pieces of legislation to reduce emissions of GHGs. Congress has not adopted any significant legislation in this respect to date, but could do so in the future. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such measures could include a carbon tax, which could result in additional direct costs to our operations. In the absence of such national legislation, many states and regions have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. For example, in February 2014, Colorado adopted rules directly regulating methane emissions from the oil and gas sector.

President Obama indicated that climate change and GHG regulation was a significant priority for his second term. The President issued a Climate Action Plan in June 2013 that, among other things, calls for a reduction in methane emissions from the oil and gas sector. In November 2013, the President released an Executive Order charging various federal agencies, including the EPA, with devising and pursuing strategies to improve the country’s preparedness and resilience to climate change. In part through these executive actions, the direct regulation of methane emissions from the oil and gas sector continues to be a focus as reflected in both the EPA’s OOOOa and BLM’s venting and flaring regulations both finalized in 2016 as noted above. In addition, a lawsuit has been filed by several northeastern states that would require the EPA to more stringently regulate methane emissions from the oil and gas sector. Finally, the Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the United States initially pledged to make a 26-28 percent reduction in its GHG emissions by 2025 against a 2005 baseline and committed to periodically update this pledge every five years starting in 2020. The passage of legislation or executive and other initiatives, including those made to implement the pledges made in Paris, that limit emissions of GHGs from our equipment and operations could require us to incur costs to reduce GHG emissions, and it could also adversely affect demand for the crude oil, natural gas, and NGLs that we produce.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. Flooding that occurred in Colorado in 2013 is an example of an extreme weather event that negatively impacted our operations. If such events were to continue to occur, or become more frequent, our operations could be adversely affected in various ways, including through damage to our facilities or from increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Federal, state and local laws and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of crude oil, natural gas, and NGLs, and could prohibit hydraulic fracturing activities.

Substantially all of our drilling uses hydraulic fracturing. Hydraulic fracturing is an important and commonly used process in the completion of unconventional wells in shale, coalbed, and tight sand formations. Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the crude oil and natural gas industry in fracturing fluids under the SDWA, and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, the Emergency Planning and Community Right-to-Know Act (“EPCRA”), or other laws. Sponsors of these bills, which have been subject to various proceedings in the legislative process, including in the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. In March 2011, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released a draft assessment of the potential impacts to drinking water resources from hydraulic fracturing for public comment and peer review. The assessment concluded that while there are mechanisms by which hydraulic fracturing can impact drinking water resources, there was no evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States. The EPA’s science advisory board subsequently questioned several elements and conclusions in the EPA’s draft assessment. In December 2016, the EPA released the final report on impacts from hydraulic fracturing activities on drinking water, concluding that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified some factors that could influence these impacts. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

The EPA has begun a Toxic Substances Control Act rulemaking which will collect expansive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the rulemaking. In October 2015, the EPA also granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain “toxic chemicals” under the Toxics Release Inventory (“TRI”) program under EPCRA. The EPA determined that natural gas processing facilities may be appropriate for addition to the scope of TRI and will conduct a rulemaking process to propose such action. On January 6, 2017, the EPA issued a proposed rule to include natural gas processing facilities in the TRI program.

The EPA also finalized major new CAA standards (New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells and certain storage vessels in August 2012. The standards require, among other things, use of reduced emission completions, or green completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers, and dehydrators. Following administrative reconsideration of a portion of the 2012 rules, the EPA issued one set of final amendments to the rule in September 2013 related to storage tanks, and a second set of final amendments largely related to reduced emissions completion requirements in December 2014. Most key provisions in the new CAA standards became effective in 2015.

In January 2015, President Obama announced a comprehensive strategy to further reduce methane emissions from the oil and gas sector. As part of this strategy, in June 2016, the EPA finalized amendments to the 2012 NSPS Quad OOOO rules as well as new requirements focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. Known as NSPS OOOOa, the new rules impose, among other things, new requirements for leak detection and repair, control requirements at oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations. These additional methane reduction requirements are substantial and could increase future costs of our operations and require us to make modifications to our operations and install new equipment. In December 2016, the EPA began a process to regulate existing oil and natural gas facilities through a nationwide Information Collection Request (ICR). The ICR has two parts. First, the EPA is requesting general information about equipment at existing facilities from every operator throughout the country. Second, the EPA issued ICRs to a more targeted set of facilities, requesting more detailed information about these operations. During the fall of 2016, the EPA also issued final Control Techniques Guidelines (CTGs) for reducing volatile organic compound emissions from existing oil and natural gas equipment and processes in ozone non-attainment areas, including the Denver Front Range 8-hour ozone non-attainment area. The ICR and CTG processes could culminate in additional controls being required for our existing sources, which may increase the future costs of operations and require modifications or the installation of new equipment.

On the same day the EPA finalized the NSPS OOOOa rules, it also finalized a rule regarding source determination and permitting requirements for the onshore oil and gas industry under the CAA. The final rule defines the term “adjacent,” which is one of three factors used to determine whether stationary sources (including oil and gas equipment and activities) are considered part of a source that is subject to major source permitting requirements under the CAA. Under this final rule, the oil and gas industry and our operations could be subject to increased permitting costs and more stringent control requirements.

The EPA has also issued permitting guidance under the SDWA for the underground injection of liquids from hydraulically fractured (and other) wells where diesel is used. Depending upon how it is implemented, this guidance may create duplicative requirements in certain areas, further slow the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities by the EPA and may therefore adversely affect even companies, such as PDC, that do not use diesel fuel in hydraulic fracturing activities.

Certain other federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. Most notably, in 2015 the U.S. Department of the Interior, through the Bureau of Land Management (the “BLM”), finalized regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing on federal and tribal lands. Due to pending litigation, however, the effective date of the rule has been postponed. In November 2016, BLM finalized rules to further regulate venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. The rules require additional controls and impose new emissions and other standards on certain operations on applicable leases, including committed state or private tracts in a federally approved unit or communitized agreement that drain federal minerals. In October 2015, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed to expand its regulations in a number of ways, including increased regulation of gathering lines, even in rural areas, and proposed additional standards to revise safety regulations applicable to onshore gas transmission and gathering pipelines in 2016. In May 2015, the U.S. Department of Transportation also issued a final rule regarding the safe transportation of flammable liquids by rail. The final rule imposes certain requirements on “offerors” of crude oil, including sampling, testing, and certification requirements.

In addition, the governments of certain states, including Colorado, Texas, and Ohio, have adopted or are considering adopting laws and regulations that impose or could impose, among other requirements, stringent permitting or air emission control requirements, disclosure, wastewater disposal, baseline sampling, seismic monitoring, well construction and well location requirements on hydraulic fracturing operations, more stringent notification or consultation processes, or otherwise seek to ban underground injection of fracturing wastewater or fracturing activities altogether. For example, in January 2012, the Ohio Department of Natural Resources (“ODNR”) issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio in order to study the relationship between these wells and earthquakes reported in the area. As a result, ODNR promulgated new and more stringent regulations for certain underground injection wells, including requirements for a complete suite of geophysical logs, analytical interpretation of the logs, and enhanced monitoring and recording. More recently, in April 2014, ODNR shut down a number of well sites after a series of small earthquakes in northeast Ohio. After investigating the earthquakes and determining that the connection to hydraulic fracturing was “probable,” ODNR implemented new permit conditions, requiring that operators of well sites within three miles of a known fault must install sensitive seismic-monitoring equipment. Operators must also halt drilling if a seismic event exceeds 1.0 magnitude. In January 2014, the Railroad Commission of Texas finalized a “well integrity rule,” which updates the requirements for drilling and cementing wells, and includes new testing and reporting requirements. In October 2014, the Railroad Commission published a new rule governing the permitting of disposal wells that requires the submission of detailed information related to seismicity. This rule grants the Railroad Commission the ability to deny, modify, suspend or terminate the permit application or existing operating permit. Similar initiatives could spread to other states in which we operate. In addition, oil and gas producers may be subject to lawsuits brought by landowners for earthquake-related damages.

At the local level, some municipalities and local governments have adopted or are considering bans on hydraulic fracturing. Beginning in 2012, voters in the cities of Fort Collins, Boulder, Longmont, Broomfield and Lafayette, Colorado approved bans of varying length on hydraulic fracturing within their respective city limits. In 2014, Boulder and Larimer county lower courts overturned the bans. The cities of Longmont and Fort Collins appealed the decisions. In August 2015, the Court of Appeals requested that the Colorado Supreme Court rule on the issue. The Colorado Supreme Court struck down the Fort Collins and Longmont bans in May 2016. Nonetheless, extended moratoria, like that put in place by Boulder County in December 2016, remain a threat to oil and gas operations in Colorado.

In Texas, voters in the City of Denton approved a local ordinance banning hydraulic fracturing in November 2014. In May 2015, the Texas legislature responded by enacting a statute preempting local government regulation of oil and gas activities.

In Ohio, several municipalities have passed hydraulic fracturing bans. In February 2015, the Ohio Supreme Court ruled that local governments cannot regulate hydraulic fracturing, finding that the State of Ohio has exclusive authority over regulating this activity under the State’s oil and gas preemption law, passed in 2004. In light of the recent Ohio Supreme Court decision, activists in Ohio are calling for the repeal of the oil and gas preemption law.

In addition, lawsuits have been filed against unrelated third parties in several states, including Colorado and Ohio, alleging contamination of drinking water by hydraulic fracturing. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to crude oil, natural gas, and NGL production activities using hydraulic fracturing techniques. Additional legislation, regulation, litigation, or moratoria could also lead to operational delays or lead us to incur increased operating or capital costs in the production of crude oil, natural gas, and NGLs, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing or other drilling activities. If these legislative, regulatory, litigation, and other initiatives cause a material decrease in the drilling of new wells or an increase in drilling costs, our profitability could be materially impacted.

Environmental and overall public scrutiny focused on the oil and gas industry is increasing. The current trend is to increase regulation of our operations and the industry. We are subject to complex federal, state, local, and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production, and marketing operations are regulated extensively at the federal, state, and local levels. Environmental and other governmental laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning crude oil and natural gas wells and associated facilities. Under these laws and regulations, we could also be liable for personal injuries, property damage, and natural resource or other damages. Similar to our competitors, we incur substantial operating and capital costs to comply with such laws and regulations. These compliance costs may put us at a competitive disadvantage compared to larger companies in the industry which can more easily capture economies of scale with respect to compliance. Failure to comply with these laws and regulations may result in various sanctions, including the suspension or termination of our operations or other operational impediments, and could subject us to administrative, civil, and criminal penalties. Moreover, public interest in environmental protection has increased in recent years-particularly with respect to hydraulic fracturing-and environmental organizations have opposed, with some success, certain drilling projects. These regulations also affect our operations, increase our costs of exploration and production, and limit the quantity of crude oil, natural gas, and NGLs that we can produce and market.

A major risk inherent in our drilling plans is the possibility that we will be unable to obtain needed drilling permits from relevant governmental authorities in a timely manner. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable or unexpected conditions or costs could have a material adverse effect on our ability to explore or develop our properties. Additionally, the crude oil and natural gas regulatory environment could change in ways that substantially increase our financial and managerial compliance costs, increase our exposure to potential damages or limit our activities.

The election of President Trump has resulted in uncertainty with respect to the future regulatory environment affecting the oil and natural gas industry. This uncertainty may affect how our industry is regulated as well as the level of public interest in environmental protection and may result in new or different pressures being exerted. For example, public interest groups may increase their use of litigation as a means to continue to exert pressure on the oil and natural gas industry. Accordingly, while we expect regulatory and enforcement pressures on our business to continue at federal, state, and local levels, the nature, level, and source of such pressures may change.

In August 2015, we received the Information Request from the EPA. The Information Request seeks, among other things, information related to the design, operation, and maintenance of our production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focuses primarily on 46 of our production facilities and asks that we conduct certain sampling and analyses at the identified 46 facilities. We responded to the Information Request in January 2016. We cannot predict the outcome of this matter at this time. Certain other operators in the area have been assessed penalties following similar information requests.

In a related Clean Air Act development, on October 1, 2015, the EPA announced its final rule lowering the existing 75 part per billion (“ppb”) NAAQS for ozone under the CAA to 70 ppb. The lower ozone NAAQS could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. In addition, the state of Colorado’s non-attainment status was bumped up from “marginal” to “moderate” for the Denver Metro North Front Range Ozone 8-Hour Non-Attainment area. This increase in non-attainment status triggers significant additional obligations for the State under the CAA. In 2016, the state undertook rulemaking to address the new “moderate” status, culminating in, among others, the incorporation of two existing state-only requirements for oil and natural gas operations into the federally-enforceable State Implementation Plan ("SIP"). In 2017, as part of the federal Control Techniques Guideline (“CTG”) process for oil and natural gas, Colorado will begin a stakeholder and rulemaking effort to compare the CTGs to existing Colorado requirements to ensure they meet applicable federal requirements. This process could result in new or more stringent air quality control requirements applicable to our operations.

In addition, our activities are subject to regulations governing conservation practices, protection of wildlife and habitat, and protection of correlative rights by state governments. For example, the federal Endangered Species Act (“ESA”) and analogous state laws restrict activities that may adversely affect endangered and threatened species or their habitat. The designation of previously unidentified endangered or threatened species or their habitat in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. For example, the U.S. Fish and Wildlife Service in May 2014 proposed a rule to alter how that agency designates critical habitat. That rule was finalized in 2016 and, depending on how it is implemented, could expand the reach of the ESA.

At the state level the COGCC issued a rule in 2013 governing mandatory minimum setbacks between oil and gas wells and occupied buildings and other areas. Also in 2013, the COGCC issued rules that require baseline sampling of certain ground and surface water in most areas of Colorado and impose stringent spill reporting and remediation requirements. These new sampling requirements could increase the costs of developing wells in certain locations. Other regulatory amendments and policies recently adopted or being proposed by the COGCC address wellbore integrity, hydraulic fracturing, well control, waste management, spill reporting, development of large scale facilities in urban mitigation areas, and certain local government notice requirements. In addition to increasing costs of operation and permitting times, some of these rules and policies, as well as litigation by public interest groups challenging application of these rules or policies, could prevent us from drilling wells on certain locations we plan to develop, thereby reducing our reserves as well as our future revenues.

In addition, during 2014, the Colorado Oil and Gas Conservation Act was amended to increase the potential sanctions for violating the Act or its implementing regulations, orders, or permits. These amendments increase the maximum penalty per violation per day from $1,000 to $15,000; eliminate a $10,000 maximum penalty for violations that do not result in significant waste of oil and gas resources, damage to correlative rights, or adverse impact to public health, safety, or welfare; require the COGCC to assess a penalty for each day there is evidence of a violation; and authorize the COGCC to prohibit the issuance of new permits and suspend certificates of clearance for egregious violations resulting from gross negligence or knowing and willful misconduct. In December 2014, the COGCC convened a hearing and adopted proposed amendments to its regulations to implement this new legislation and address certain other issues. Among other things, the amendments create a new process for calculating penalties, new standards for determining days of violation and penalty amounts, new restrictions on the use of informal enforcement procedures, and penalty reductions for voluntary disclosures. Following the adoption of this new penalty scheme, Colorado operators have experienced increased penalties for violations within COGCC’s jurisdiction.

In 2015, the COGCC convened hearings on regulations for large facilities located in urban mitigation areas. These new rules require best available technology and include required mitigations for emissions, flaring, fire, fluid leak detection, repair, reporting, automated well shut-in, storage tank pressure control, and proppant dust control. During these hearings, COGCC staff reported there would also be site-specific mitigation requirements for noise, ground and surface water protection, visual impacts, and remote stimulation. After debate, the rule did not include duration limits despite an opinion from the State Attorney General Office that the COGCC possessed authority to impose duration limits under current and existing statutes.

In February 2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") finalized regulations imposing stringent new requirements relating to air emissions from oil and gas facilities in Colorado. The new rules impose significantly more stringent control, monitoring, recordkeeping, and reporting requirements than those required under comparable new federal rules. In addition, as part of the rule, the AQCC approved the direct regulation of hydrocarbon (i.e., methane) emissions from the Colorado oil and gas sector. Such state-only, direct regulation of methane (a greenhouse gas) from a single industry sector affected federal regulations from the EPA and the BLM, and continues to have the potential to adversely affect operations in Colorado as well as in other parts of the country. Along the same lines, local governments are undertaking air quality studies to assess potential public health impacts from oil and gas operations. These studies, in combination with other air quality-related studies that are national in scope, may result in the imposition of additional regulatory requirements on oil and gas operations.

CERCLA (or the "Superfund law") and some comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. This includes potential liability for activities on properties we may currently own or operate upon, but where previous owner/operators caused the release of a hazardous substance. In addition, we may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been or threaten to be released into the environment. From time to time, we are involved in remediation activities at such properties.

Regulatory focus on worker safety and health regulations involving operating hazards in oil and natural gas exploration and production activities is also increasing. One example is a recent investigation by the U.S. Occupational Safety and Health Administration ("OSHA") and other governmental authorities regarding potential worker exposure to hydrocarbon vapors from certain fuel transfer and related tasks. Several recent worker fatalities at oil and gas facilities nationwide are being reviewed by OSHA and other governmental authorities for a potential link to hydrocarbon vapor exposure. Regulatory requirements generally relating to worker exposure to hydrocarbon vapors could be increased or receive heightened scrutiny going forward. For example, in December 2015, the Department of Labor and the Department of Justice, Environment and Natural Resources Division released a Memorandum of Understanding ("MOU"), announcing an inter-agency effort to increase the enforcement of workplace safety crimes that occur in conjunction with environmental crimes. Consistent with this MOU, DOJ will look for additional felony violations (such as false statements and willful violations of certain standards) when prosecuting safety crimes in order to heighten prospective penalties and strengthen enforcement. In October 2016, OSHA issued a Regional Emphasis Program (REP) notice for the purpose of conducting safety and hazard inspections at oil and gas industry facilities in Region III (Pennsylvania and West Virginia). Similar notices could result in increased OSHA activities in the areas in which we operate.

Other potential laws and regulations affecting us include new or increased severance taxes proposed in several states, including Ohio. This could adversely affect our existing operations in the state and the economic viability of future drilling. Additional laws, regulations, or other changes could significantly reduce our future growth, increase our costs of operations, and reduce our cash flows, in addition to undermining the demand for the crude oil, natural gas, and NGLs we produce.

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

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The changes could include, but are not limited to (i) the repeal of the percentage depletion deduction for crude oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could result in higher federal income taxes, which could negatively affect our financial condition and results of operations. In addition, proposals are made from time to time in states where we operate to implement or increase severance or other taxes at the state level, and any such additional taxes would have similarly adverse effects on us.

Derivatives legislation and regulation could adversely affect our ability to hedge crude oil and natural gas prices and increase our costs and adversely affect our profitability.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted into law. The Dodd-Frank Act regulates derivative transactions, including our commodity hedging swaps, and could have a number of adverse effects on us, including the following:

- The Dodd-Frank Act may limit our ability to enter into hedging transactions, thus exposing us to additional risks related to commodity price volatility; commodity price decreases would then have an increased adverse effect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flows, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.
- If, as a result of the Dodd-Frank Act or its implementing regulations, we are required to post cash collateral in connection with our derivative positions, this would likely make it impracticable to implement our current hedging strategy.
- Our derivatives counterparties are subject to significant requirements imposed as a result of the Dodd-Frank Act. We expect that these requirements will increase the cost to hedge because there will be fewer counterparties in the market and increased counterparty costs will be passed on to us.

The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms. The election of President Trump has resulted in uncertainty with respect to the future of the Dodd-Frank Act generally and derivative regulation specifically, and the future impact this may have on PDC is currently unknown.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to various legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations, or liquidity.

Environmental

In August 2015, we received the Information Request from the EPA. The Information Request sought, among other things, information related to the design, operation, and maintenance of our Wattenberg Field production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focused on historical operation and design information for 46 of our production facilities and asks that we conduct sampling and analyses at the identified 46 facilities. We responded to the Information Request in January 2016. Throughout 2016, we continued to meet with the EPA, Department of Justice, and Colorado Department of Public Health and Environment, and in December we received a draft consent decree from the EPA.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. § 25-7-115(2) from the Colorado Department of Public Health and Environment's Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate, and maintain certain condensate collection, storage, processing, and handling operations to minimize leakage of volatile organic compounds at 65 facilities consistent with applicable standards under Colorado law. This matter has been combined with the matter discussed above. The ultimate outcome related to these combined actions has not been determined at this time.

In 2014, we experienced a loss of well control while drilling an oil and gas well in Morgan County, Ohio. The event resulted in a release of well fluids, including oil based drilling mud. We have completed the appropriate remediation to address the release. In August 2015, the EPA issued us a Notice of Intent seeking civil penalties. We and the EPA settled this matter for a civil fine of approximately $152,000 in November 2015.

Action Regarding Firm Transportation Contracts

A group of 42 independent West Virginia natural gas producers has filed a lawsuit in Marshall County, West Virginia, naming Dominion Transmission, Inc. ("Dominion"), certain entities affiliated with Dominion, and our subsidiary RNG as defendants, alleging various contractual, fiduciary and related claims against the defendants, all of which are associated with firm transportation contracts entered into by plaintiffs and relating to pipelines owned and operated by Dominion and its affiliates. RNG and Dominion have removed the case to the U.S. District Court for the Northern District of West Virginia and have filed pre-trial pleadings. At this time, the case has been remanded back to the state court. RNG is unable to estimate any potential damages associated with the claims, but believes the complaint is without merit and intends to vigorously pursue its defenses.

Class Action Regarding 2010 and 2011 Partnership Purchases

In December 2011, the Company and its wholly-owned merger subsidiary were served with an alleged class action on behalf of unit holders of 12 former limited partnerships, related to its repurchase of the 12 partnerships, which were formed beginning in late 2002 through 2005. The mergers were completed in 2010 and 2011. The action was filed in U.S. District Court for the Central District of California and was titled *Schulein v. Petroleum Development Corp*. The complaint primarily alleged that the disclosures in the proxy statements issued in connection with the mergers were inadequate, and a state law breach of fiduciary duty. In January 2014, the plaintiffs were certified as a class by the court.

In October 2014, the Company and plaintiffs' counsel reached a settlement agreement in principle that was given final court approval in March 2015. Under this settlement agreement, the plaintiffs received a cash payment of $37.5 million in January 2015, of which the Company paid $31.5 million and insurers paid $6.0 million. In March 2015, the class action was dismissed with prejudice and all class claims were released. In 2014, the Company recorded an expense of $31.5 million related to this litigation, which was included in general and administrative expense in the consolidated statements of operations.

Further information regarding our legal proceedings can be found in the footnote titled *Commitments and Contingencies – Litigation* to our consolidated financial statements included elsewhere in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDERS MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol PDCE. The following table sets forth the range of high and low sales prices for our common stock based on intra-day trading for each of the periods presented:

	High	Low
January 1 - March 31, 2015	$ 55.47	$ 37.62
April 1 - June 30, 2015	61.41	51.01
July 1 - September 30, 2015	61.55	41.17
October 1 - December 31, 2015	64.99	52.46
January 1 - March 31, 2016	60.56	42.68
April 1 - June 30, 2016	65.86	51.92
July 1 - September 30, 2016	71.00	50.12
October 1 - December 31, 2016	84.88	59.82

As of February 15, 2017, we had approximately 675 stockholders of record. Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our revolving credit facility as well as the indenture agreements governing our 2024 Senior Notes and our 7.75% senior notes due 2022 ("2022 Senior Notes"), and we presently intend to continue a policy of using retained earnings for expansion of our business.

The following table presents information about our purchases of our common stock during the three months ended December 31, 2016:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 - 31, 2016	5,742	$ 66.98
November 1 - 30, 2016	—	$ —
December 1 - 31, 2016	19,969	$ 73.37
Total fourth quarter 2016 purchases	25,711	$ 71.94

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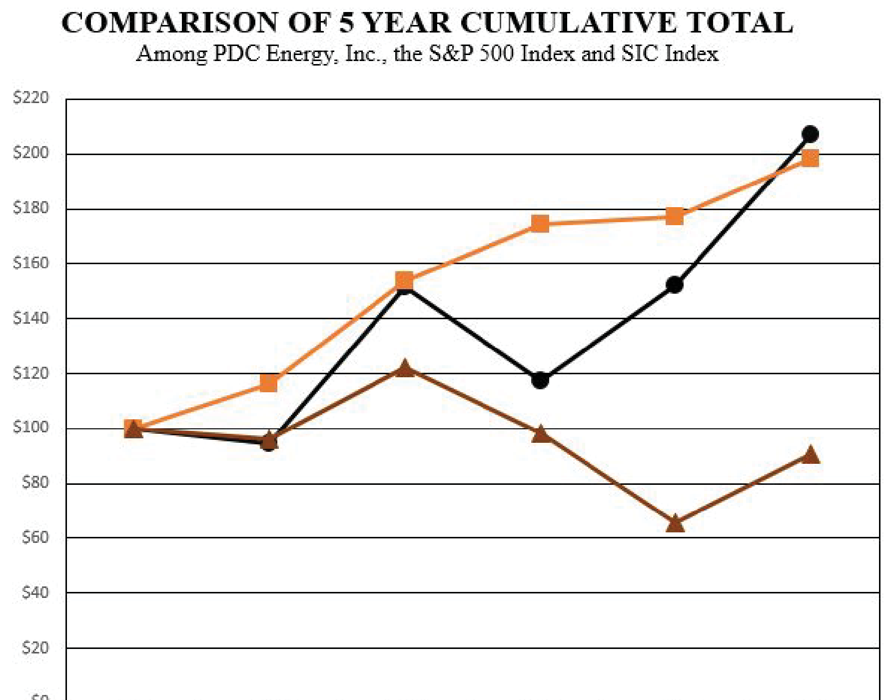
(1) *Purchases primarily represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.*

STOCKHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2016, with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the Standard Industrial Code ("SIC") Index. The SIC Index is a weighted composite of 211 crude petroleum and natural gas companies. The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2011, and in the S&P 500 Index and the SIC Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.



	12/11	12/12	12/13	12/14	12/15	12/16
PDC Energy	$100.00	$94.59	$151.58	$117.54	$152.04	$206.72
S&P 500	100.00	116.00	153.58	174.60	177.01	198.18
SIC Index	100.00	95.97	122.22	98.23	65.81	90.52

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended/As of December 31,				
	2016 (1)	2015	2014	2013	2012
	(in millions, except per share data and as noted)				
Statement of Operations (From Continuing Operations) (2):					
Crude oil, natural gas and NGLs sales	$ 497.4	$ 378.7	$ 471.4	$ 340.8	$ 228.0
Commodity price risk management gain (loss), net of actual settlements and changes in mark-to-market valuation adjustments	(125.7)	$ 203.2	310.3	(23.9)	29.3
Total revenues	382.9	595.3	856.2	392.7	307.1
Income (loss) from continuing operations	(245.9)	(68.3)	107.3	(21.1)	(19.4)
Earnings (loss) per share from continuing operations:					
Basic	$ (5.01)	$ (1.74)	$ 3.00	$ (0.65)	$ (0.70)
Diluted	(5.01)	(1.74)	2.93	(0.65)	(0.70)
Statement of Cash Flows:					
Net cash flows from:					
Operating activities	$ 486.3	$ 411.1	$ 236.7	$ 159.2	$ 174.7
Investing activities	(1,509.1)	(604.3)	(474.1)	(217.1)	(451.9)
Financing activities	1,266.1	178.0	60.3	248.7	271.4
Capital expenditures from development and exploration activities (3)	436.9	599.5	623.8	384.7	344.2
Acquisitions of crude oil and natural gas properties	1,073.7	—	—	9.7	312.2
Balance Sheet:					
Total assets	$ 4,485.8	$ 2,370.5	$ 2,331.1	$ 1,991.7	$ 1,777.9
Working capital	129.2	30.7	89.5	90.0	(67.6)
Total debt, net of unamortized discount and debt issuance costs	1,044.0	642.4	655.5	593.9	637.5
Total equity	2,622.8	1,287.2	1,137.4	967.6	703.2
Pricing and Production Expenses From Continuing Operations (per Boe and as a percent of sales for Production Taxes):					
Average sales price (excluding net settlements on derivatives)	$ 22.43	$ 24.64	$ 50.72	$ 52.23	$ 46.85
Lease operating expenses	$ 2.70	$ 3.71	$ 4.56	$ 5.18	$ 5.54
Transportation, gathering, and processing	$ 0.83	$ 0.66	$ 0.49	$ 0.79	$ 0.56
Production taxes	$ 1.42	$ 1.20	$ 2.76	$ 3.33	$ 2.86
Production taxes as a percent of sales	6.3%	4.9%	5.4%	6.4%	6.1%
Production (MBoe):					
Production from continuing operations	22,175.9	15,369.4	9,294.4	6,524.7	4,866.5
Production from discontinued operations	—	—	1,093.0	2,032.6	3,458.7
Total production	22,175.9	15,369.4	10,387.4	8,557.3	8,325.2
Total proved reserves (MMBoe) (4)(5)	341.4	272.8	250.1	265.8	192.8

(1) *In 2016, we closed acquisitions in the Delaware Basin for aggregate consideration of approximately $1.76 billion. See footnotes titled Properties and Equipment - Delaware Basin Acreage Acquisition and Business Combination to our consolidated financial statements included elsewhere in this report for further information regarding these acquisitions.*

(2) *In 2014, we completed the sale of our ownership interest in PDCM. Our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations. See footnote titled Divestiture and Discontinued Operations to our*

elsewhere in this report for further information regarding this divestiture.

(3) *Includes impact of change in accounts payable related to capital expenditures.*

(4) *Includes total proved reserves related to our Marcellus Shale and shallow Upper Devonian Appalachian Basin assets of 40 MMBoe and 30 MMBoe as of December 31, 2013 and 2012, respectively. The joint venture that owned these reserves was sold in late 2014.*

(5) *Includes total proved reserves related to our Piceance Basin and North Eastern Colorado ("NECO") assets of 14 MMBoe as of December 31, 2012. These assets were sold in 2013.*

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our consolidated financial statements and related notes to consolidated financial statements included elsewhere in this report. Further, we encourage you to revisit the *Special Note Regarding Forward-Looking Statements* in Part I of this report.

SUMMARY

2016 Financial Overview of Operations and Liquidity

Production volumes increased to 22.2 MMBoe in 2016, including 0.2 MMBoe from our recent acquisitions in the Delaware Basin, compared to 15.4 MMBoe in 2015, representing an increase of 44 percent. The increase in production volumes was primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Crude oil production increased 25 percent in 2016, which comprised approximately 39 percent of total production. Natural gas production increased 55 percent and NGLs increased 70 percent in 2016 compared to 2015. These increases were the result of our shift in focus to the higher rate of return drilling projects located in the higher gas to oil ratio inner and middle core areas of the Wattenberg Field during the first half of 2016. On a combined basis, total liquids production of crude oil and NGLs comprised 61 percent of production in 2016 compared to 64 percent of production in 2015, a decrease of four percent. For the month ended December 31, 2016, we maintained an average production rate of 73 MBoe per day, up from 52 MBoe per day for the month ended December 31, 2015.

Crude oil, natural gas, and NGLs sales increased to $497.4 million in 2016 compared to $378.7 million in 2015, due to a 44 percent increase in production, offset in part by a nine percent decrease in the weighted-average realized prices of crude oil, natural gas, and NGLs, driven by lower commodity prices and changes in commodity mix. Crude oil, natural gas, and NGLs sales, coupled with the impact of positive net settlements of derivatives, also increased in 2016 as compared to 2015. When combining the physical commodity sales and the net settlements received on our commodity derivative instruments, the total net revenues increased 14 percent to $705.4 million in 2016 from $617.6 million in 2015. The low crude oil and natural gas index prices in 2016 and 2015 were the primary reason for the positive net settlements of $208.1 million and $238.9 million on commodity derivatives in 2016 and 2015, respectively.

In 2016, we generated a net loss of $245.9 million, or $5.01 per diluted share. In the same period we generated $435.6 million of adjusted EBITDA, a non-U.S. GAAP financial measure, and invested $396.4 million in the development and exploration of our oil and natural gas properties, which is net of the change in accounts payable related to capital expenditures. Our cash flow from operations was $486.3 million and our adjusted cash flow from operations was $466.8 million in 2016. Adjusted EBITDA and adjusted cash flow from operations are non-U.S. GAAP financial measures as defined and more fully described later in this section.

Other significant changes impacting our 2016 results of operations include the following:

- The net change in the fair value of unsettled derivative positions in 2016 was a loss of $333.8 million compared to a loss of $35.8 million in 2015. The decrease in the fair value of unsettled derivative positions is largely driven by the normal monthly settlements of the commodity derivative instruments in 2016. Additionally, the change in fair value was attributable to hedging positions entered into in 2016 at lower strike prices and the upward shift in the crude oil and natural gas forward curves that occurred during 2016 versus a downward shift in 2015.
- Production tax expense increased to $31.4 million in 2016 from $18.4 million in 2015 due to increased production of 44 percent and higher overall sales proceeds. Additionally, we had a higher effective production tax rate in 2016 primarily from a reduction in ad valorem credits from the prior year to offset current year severance taxes due.
- Impairment of crude oil and natural gas properties was $10.0 million in 2016 compared to $161.6 million in 2015. The 2016 impairments are a result of the write-off of certain leases that were no longer part of our development plan and to reflect the fair value of other land and buildings that are held for sale. The Utica Shale was the largest component of the 2015 write-down which included both producing and non-producing crude oil and natural gas properties.
- General and administrative expense increased to $112.5 million in 2016 compared to $90.0 million in 2015. The increase was attributable to professional and transaction fees related to the Delaware Basin acquisitions and increases in payroll and employee benefits, as we increased our staff by nine percent over the course of 2016.
- Depreciation, depletion, and amortization expense increased to $416.9 million in 2016 compared to $303.3 million in 2015, due to the increase in production volumes from year to year.
- We recorded a provision for uncollectible notes receivable of $44.0 million in the first quarter of 2016 to impair a note receivable.
- Interest expense increased to $62.0 million in 2016 from $47.6 million in 2015. The increase was primarily attributable to a $9.3 million charge for the bridge loan commitment related to our initial Delaware Basin acquisition, a $7.4 million increase in interest expense resulting from the issuance of our 2024 Senior Notes, and a $2.9 million increase in interest expense for the issuance of our 2021 Convertible Notes in September 2016. The increases were partially offset by a $5.1 million decrease in interest expense resulting from the net settlement of our 2016 Convertible Notes in May 2016.

Available liquidity as of December 31, 2016 was $932.4 million compared to $402.2 million as of December 31, 2015. Available liquidity as of December 31, 2016 is comprised of $244.1 million of cash and cash equivalents and $688.3 million available for borrowing under our revolving credit facility. In December 2016, pursuant to an amendment to our credit facility and in conjunction with the closing of the acquisitions of the Delaware Basin properties, we increased the aggregate commitment under our revolving credit facility from $450 million to $700 million.

In March 2016, we completed a public offering of 5.9 million shares of our common stock at a price to us of $50.11 per share. Net proceeds of the offering were $296.6 million, after deducting offering expenses and underwriting discounts. We used the net proceeds of the offering to repay all amounts then outstanding on our revolving credit facility, the principal and interest owed upon the maturity of the $115 million face value of 2016 Convertible Notes in May 2016 and for general corporate purposes. We settled the 2016 Convertible Notes with a combination of cash and stock, paying the aggregate principal amount, plus cash for fractional shares, totaling approximately $115 million. The conversion price for the 2016 Convertible Notes was $42.40 per share, resulting in the issuance of 792,406 shares of common stock for the excess conversion value.

In June 2016, we entered into definitive agreements with Noble Energy Inc. and certain of its subsidiaries ("Noble") to consolidate certain acreage positions in the core Wattenberg Field. In September 2016, we closed the acreage exchange transaction. Pursuant to the transaction, we exchanged leasehold acreage and, to a lesser extent, interests in certain development wells. Upon closing, we received approximately 13,500 net acres in exchange for approximately 11,700 net acres, with no cash exchanged between the parties. The difference in net acres was primarily due to variances in leasehold net revenue interests and third-party mid-stream contracts. This acreage trade has resulted in opportunities for longer length horizontal laterals with increased working interests, while minimizing potential surface impact.

In September 2016, we sold 9.1 million shares of common stock for net proceeds of $558.5 million, we issued the 2024 Senior Notes for net proceeds of $392.2 million, and we issued the 2021 Convertible Senior Notes convertible at 11.7113 shares of common stock per $1,000 principal amount for net proceeds of $193.9 million (collectively, the "Securities Issuances"). The total net proceeds of $1.1 billion from the Securities Issuances were used to fund a portion of the purchase price of the acquisitions of the Delaware Basin properties, pay related fees and expenses, and for general corporate purposes.

We intend to continue to manage our liquidity position by a variety of means, including through the generation of cash flow from our operations, investment in projects with attractive rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative program, utilization of our borrowing capacity under our revolving credit facility, and the pursuit of capital markets transactions from time to time.

Delaware Basin Acquisitions

Through a deliberate and disciplined process of searching for, and evaluating, a large-scale acquisition in a U.S. onshore basin that diversifies our operations and is capable of creating material long-term value-added growth, we recently acquired proved and unproved leasehold in the Delaware Basin in Reeves and Culberson Counties in Texas. The acquisition criteria focused on four key attributes:

- top-tier acreage in core geologic positions;
- significant drilling inventory with additional expansion through down spacing;
- portfolio optionality for capital allocation and diversification; and
- the ability to deliver long-term corporate accretion.

We believe the Delaware Basin acquisitions met these criteria.

We completed two acquisition transactions associated with the Delaware Basin. The first acquisition closed in early December 2016, and we acquired acreage, approximately 30 producing wells and related midstream infrastructure in Reeves and Culberson Counties, Texas, for an aggregate consideration to the sellers of approximately $1.64 billion, which was comprised of approximately $952.1 million in cash (including the repayment of $40.0 million of debt from the seller at closing) and 9.4 million shares of our common stock valued at approximately $690.7 million at the time the acquisition closed. The total purchase price remains subject to certain post-closing adjustments as of the date of this report and we expect that it may take into mid-2017 until all post-closing adjustments are settled.

The acquisitions were accounted for under the acquisition method. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The details of the purchase price and the preliminary allocation of the purchase price for the first transaction are presented below (in thousands):

Acquisition costs:		
Cash, net of cash acquired	$	912,142
Retirement of seller's debt		40,000
Total cash consideration		952,142
Common stock, 9.4 million shares		690,702
Other purchase price adjustments		1,026
Total acquisition costs	$	1,643,870

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Current assets	$	8,201
Crude oil and natural gas properties - proved		216,000
Crude oil and natural gas properties - unproved		1,721,334
Infrastructure, pipeline, and other		32,590
Construction in progress		12,148
Goodwill		62,041
Total assets acquired		2,052,314
Liabilities assumed:		
Current liabilities		(24,844)
Asset retirement obligations		(3,705)
Deferred tax liabilities, net		(379,895)
Total liabilities assumed		(408,444)
Total identifiable net assets acquired	$	1,643,870

The 2016 results of operations of the acquired properties in the first transaction had a loss from operations of $1.7 million, which is included in our consolidated statements of operations for 2016.

The second transaction closed at the end of December 2016. In this transaction, we acquired primarily unproved acreage for cash consideration of $120.6 million. This acquisition is also subject to final settlement as there were some limited producing assets. The final settlement is not expected to be completed until mid-2017.

2016 Drilling Overview

During 2016, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. Through July 2016, we ran four automated drilling rigs in the Wattenberg Field. In August 2016, we decreased the number of automated drilling rigs to three in anticipation of higher working interests in wells drilled resulting from the acreage exchange. During 2016, we spud 128 gross horizontal, (109.4 net), wells and turned-in-line 140 gross, (109.7 net), horizontal wells in the Wattenberg Field. Also in the Wattenberg Field, we participated in 17 gross (3.6 net) horizontal non-operated wells that were spud and 24 gross (5.0 net) horizontal non-operated wells which were turned-in-line. In the Utica Shale, we completed five gross horizontal (4.5 net) wells, all of which were turned-in-line in 2016. Following the closing of our acquisitions in the Delaware Basin, we spud one well (0.9 net), and turned-in-line another well (1.0 net) prior to the end of 2016.

The following table summarizes our 2016 drilling and completion activity:

	Gross	Net
In-process as of December 31, 2015	102	63.4
Wells spud during the period	144	112.2
Wells turned-in-line to sales	(170)	(120.2)
Acquired in-process	5	4.9
In-process as of December 31, 2016	81	60.3

Our in-process wells represent wells that are in the process of being drilled and/or have been drilled and are waiting to be fractured and/or for gas pipeline connection. We do not have a practice of inventorying our drilled but uncompleted wells. The majority of these in-process wells at each year end are drilled, but not completed as we do not begin the completion process until the entire well pad is drilled. All costs incurred through the end of the period have been capitalized or accrued to capital, while the capital investment to complete the wells will be incurred in the following year. The cost of completing these wells is included in our 2017 capital forecast.

2017 Operational Outlook

We expect our production for 2017 to range between 30.0 MMBoe to 33.0 MMBoe and we estimate that our production rate will average approximately 82,200 to 90,400 Boe per day. We expect that 41 percent to 43 percent of our 2017 production will be comprised of crude oil and 20 percent to 22 percent will be NGLs, for total liquids of 61 percent to 65 percent of our total 2017 production. Our previously-announced 2017 capital forecast of between $725 million and $775 million is focused on continued development in the core Wattenberg Field and the integration of the core Delaware Basin assets. Due to recent cost escalation for services and the modification of our drilling schedule in the Delaware Basin, where we have accelerated the deployment of an additional drilling rig, we currently expect that our 2017 capital investment will be at or near the high end of the range. These changes to our capital investment outlook are not expected to impact our expected 2017 production as the incremental wells drilled are contemplated to be turned-in-line to sales late in the year.

Wattenberg Field. The 2017 investment outlook of approximately $470 million in the Wattenberg Field anticipates a three to four-rig drilling program based on our current commodity price outlook. Approximately $460 million of our 2017 capital investment program is expected to be allocated to development activities, comprised of approximately $440 million for our operated drilling program and approximately $20 million for wells drilled and operated by others. The remainder of the Wattenberg Field capital investment program is expected to be used for miscellaneous workover and capital projects. Wells in the Wattenberg Field typically have productive horizons at a depth of approximately 6,500 to 7,500 feet below the surface. In 2017, to help manage our priorities, we now anticipate spudding 137 and turning-in-line approximately 139 horizontal operated wells with lateral lengths of 5,000 to 10,000 feet.

Delaware Basin. Our 2017 investment outlook contemplates operating a two-rig to four-rig program in the Delaware Basin from time to time during the year. Total capital investment in the Delaware Basin is estimated to be $300 million, of which approximately $235 million is allocated to spud 31 and turn-in-line an estimated 26 wells. Of the the 26 planned turn-in-lines, 14 are expected to have laterals of approximately 10,000 horizontal feet with an estimated 70 to 75 completion stages per well. Similarly spaced completion stages are anticipated for the remaining 12 turn-in-lines. Wells in the Delaware Basin typically have productive horizons at a depth of approximately 9,000 to 11,000 feet below the surface. Based on the timing of our operations and the requirements to hold acreage, we may adapt our capital investment program to drill wells in addition to those currently anticipated, as we are continuing to analyze terms of the leaseholds related to our recent acquisitions of properties in the basin. We plan to invest approximately $35 million for leasing, seismic, and technical studies with an additional $30 million for midstream-related projects including gas connections, salt water disposal wells, and surface location infrastructure.

Utica Shale. At this time, we are currently evaluating all of our strategic alternatives with respect to our Utica Shale position. As a result of such evaluation, we are deferring our 2017 planned expenditure of $18 million to drill, complete, and turn-in-line two wells in Guernsey County. In 2017, our capital investment program for the Utica Shale is expected to include between $2 million to $3 million for additional leasing. Such leasing may be necessary to complete certain drilling operations if we decide to continue development of our existing position in the northern portion of our acreage.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations:

	Year Ended December 31,				
				Percent Change	
	2016	2015	2014	2016-2015	2015-2014
	(dollars in millions, except per unit data)				
Production					
Crude oil (MBbls)	8,728	6,984	4,322	25.0 %	61.6 %
Natural gas (MMcf)	51,730	33,302	19,298	55.3 %	72.6 %
NGLs (MBbls)	4,826	2,835	1,756	70.2 %	61.4 %
Crude oil equivalent (MBoe)	22,176	15,369	9,294	44.3 %	65.4 %
Average Boe per day	60,590	42,108	25,464	43.9 %	65.4 %
Crude Oil, Natural Gas and NGLs Sales					
Crude oil	$ 348.9	$ 280.3	$ 348.6	24.5 %	(19.6)%
Natural gas	91.6	68.0	74.7	34.7 %	(9.0)%
NGLs	56.9	30.4	48.1	87.2 %	(36.8)%
Total crude oil, natural gas, and NGLs sales	$ 497.4	$ 378.7	$ 471.4	31.3 %	(19.7)%
Net Settlements on Commodity Derivatives (1)					
Crude oil	$ 165.2	$ 208.9	$ 2.3	(20.9)%	*
Natural gas	42.9	30.0	(3.1)	43.0 %	*
Total net settlements on derivatives	$ 208.1	$ 238.9	$ (0.8)	(12.9)%	*
Average Sales Price (excluding net settlements on derivatives)					
Crude oil (per Bbl)	$ 39.96	$ 40.14	$ 80.67	(0.4)%	(50.2)%
Natural gas (per Mcf)	1.77	2.04	3.87	(13.2)%	(47.3)%
NGLs (per Bbl)	11.80	10.72	27.39	10.1 %	(60.9)%
Crude oil equivalent (per Boe)	22.43	24.64	50.72	(9.0)%	(51.4)%
Average Costs and Expenses (per Boe)					
Lease operating expenses	$ 2.70	$ 3.71	$ 4.56	(27.2)%	(18.6)%
Production taxes	1.42	1.20	2.76	18.3 %	(56.5)%
Transportation, gathering, and processing expenses	0.83	0.66	0.49	25.8 %	34.7 %
General and administrative expense	5.07	5.85	13.29	(13.3)%	(56.0)%
Depreciation, depletion, and amortization	18.80	19.73	20.71	(4.7)%	(4.7)%
Other Costs and Expenses					
Exploration expense	$ 4.7	$ 1.1	$ 0.9	*	16.4 %
Impairment of properties and equipment	10.0	161.6	166.8	(93.8)%	(3.1)%
Interest expense	62.0	47.6	47.8	30.3 %	(0.6)%
Gas Marketing Contribution Margin (2)	$ (1.5)	$ (0.8)	$ (0.4)	(87.5)%	(100.0)%

* Percentage change is not meaningful or equal to or greater than 300% or not applicable.
Amounts may not recalculate due to rounding.

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(1) Represents net settlements on derivatives related to crude oil and natural gas sales, which do not include net settlements on derivatives related to gas marketing.
(2) Represents sales from gas marketing, net of costs of gas marketing, including net settlements and net change in fair value of unsettled derivatives related to gas marketing activities.

Crude Oil, Natural Gas and NGLs Sales

The following tables present crude oil, natural gas, and NGLs production and weighted-average sales price for continuing operations:

	Year Ended December 31,			Change	
Production by Operating Region	2016	2015	2014	2016-2015	2015-2014
Crude oil (MBbls)					
Wattenberg Field	8,229.7	6,490.4	4,026.7	26.8 %	61.2%
Delaware Basin (1)	79.5	—	—	*	*
Utica Shale	419.1	493.4	295.2	(15.1)%	67.1%
Total	8,728.3	6,983.8	4,321.9	25.0 %	61.6%
Natural gas (MMcf)					
Wattenberg Field	48,889.1	30,752.8	17,108.9	59.0 %	79.7%
Delaware Basin (1)	373.3	—	—	*	*
Utica Shale	2,467.8	2,548.9	2,189.1	(3.2)%	16.4%
Total	51,730.2	33,301.7	19,298.0	55.3 %	72.6%
NGLs (MBbls)					
Wattenberg Field	4,567.5	2,615.9	1,605.7	74.6 %	62.9%
Delaware Basin (1)	36.1	—	—	*	*
Utica Shale	222.2	219.4	150.5	1.3 %	45.8%
Total	4,825.8	2,835.3	1,756.2	70.2 %	61.4%
Crude oil equivalent (MBoe)					
Wattenberg Field	20,945.4	14,231.7	8,483.8	47.2 %	67.8%
Delaware Basin (1)	177.8	—	—	*	*
Utica Shale	1,052.7	1,137.7	810.6	(7.5)%	40.4%
Total	22,175.9	15,369.4	9,294.4	44.3 %	65.4%

(1) Reflects the Delaware Basin acquisitions that occurred in December 2016.
* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

Weighted-Average Sales Price by Operating Region *(excluding net settlements on derivatives)*	Year Ended December 31, 2016	2015	2014	Change 2016-2015	2015-2014
Crude oil (per Bbl)					
Wattenberg Field	$ 39.99	$ 40.03	$ 80.61	(0.1)%	(50.3)%
Delaware Basin (1)	49.28	—	—	*	*
Utica Shale	37.62	41.59	81.52	(9.5)%	(49.0)%
Weighted-average price	39.96	40.14	80.67	(0.4)%	(50.2)%
Natural gas (per Mcf)					
Wattenberg Field	1.77	2.06	3.94	(14.1)%	(47.7)%
Delaware Basin (1)	2.78	—	—	*	*
Utica Shale	1.58	1.85	3.35	(14.6)%	(44.8)%
Weighted-average price	1.77	2.04	3.87	(13.2)%	(47.3)%
NGLs (per Bbl)					
Wattenberg Field	11.59	10.58	25.95	9.5 %	(59.2)%
Delaware Basin (1)	17.87	—	—	*	*
Utica Shale	15.11	12.43	42.76	21.6 %	(70.9)%
Weighted-average price	11.80	10.72	27.39	10.1 %	(60.9)%
Crude oil equivalent (per Boe)					
Wattenberg Field	22.38	24.64	51.10	(9.2)%	(51.8)%
Delaware Basin (1)	31.50	—	—	*	*
Utica Shale	21.88	24.59	46.87	(11.0)%	(47.5)%
Weighted-average price	22.43	24.64	50.72	(9.0)%	(51.4)%

(1) Reflects the Delaware Basin acquisitions that occurred in December 2016.
* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

The year-over-year change in crude oil, natural gas, and NGLs sales revenue were primarily due to the following:

	Year Ended December 31, 2016	2015
	(in millions)	
Increase in production from development of existing properties	$ 128.8	$ 298.5
Increase in production from acquisitions	0.2	—
Decrease in average crude oil price	(1.6)	(283.1)
Decrease in average natural gas price	(14.0)	(60.9)
Increase (decrease) in average NGLs price	5.2	(47.2)
Total increase (decrease) in crude oil, natural gas and NGLs sales revenue	$ 118.6	$ (92.7)

Production volumes increased 44 percent in 2016 compared to 2015. Crude oil production increased 25 percent in 2016, which comprised approximately 39 percent of total production. Natural gas production increased 55 percent and NGLs increased 70 percent in 2016 compared to 2015. The increases in crude oil are different from the comparative period because of our shift in focus to the higher rate of return drilling projects located in the higher gas to oil ratio inner and middle core areas of the Wattenberg Field during the first half of 2016. On a combined basis, total liquids production of crude oil and NGLs comprised 61 percent of production in 2016 compared to 64 percent of production in 2015, a decrease of four percent. Production volumes increased 65 percent in 2015 compared to 2014. Production of crude oil, natural gas and NGLs was relatively consistent across commodities at 62 percent, 73 percent, and 61 percent, respectively, as we focused our 2015 and 2014 drilling on the middle and outer core areas of the Wattenberg Field. We currently expect our 2017 individual commodity growth and overall production growth to be similar.

Crude oil, natural gas, and NGLs sales in 2016 increased 31 percent compared to 2015. The increase was primarily attributable to higher volumes sold in 2016 of 22.2 MMBoe, up from 15.4 MMBoe in 2015. This was offset in part by a decrease in commodity prices and modest changes in the commodity mix, which resulted in a nine percent decline in the average realized price on a barrel of oil equivalent basis in 2016 compared to 2015. The higher volumes were primarily contributed from turning in-line to sales 140 new gross wells in the Wattenberg Field that delivered significant production volumes. Included in the 22.2 MMBoe is production of 0.2 MMBoe from our acquisitions of producing properties in the Delaware Basin. Our average daily sales volumes increased to 60.6 MBoe per day in 2016 compared to 42.1 MBoe per day in 2015 as a result of continued drilling and completion activities. The average NYMEX crude oil and natural gas prices decreased by 11 percent and eight percent in 2016 compared to 2015. For crude oil the change was to $43.32 per barrel in 2016 from $48.80 per barrel in 2015, and we were able to offset the majority of the decrease in the NYMEX sales prices through actions that decreased our contractual deductions to $4.39 per barrel in 2016 from $9.95 per barrel in 2015. The natural gas realized sales price decreased more than the decrease in the NYMEX price because a portion of our deductions for natural gas are based on fixed price elements and have a more pronounced effect at lower prices.

Crude oil, natural gas, and NGLs sales in 2015 decreased 20 percent compared to 2014. The decrease was primarily attributable to a significant decrease in commodity prices, resulting in a 51 percent decline in the price of a barrel of crude oil equivalent in 2015 compared to 2014. The decrease was offset in part by the higher volumes sold in 2015 of 15.4 MMBoe, up from 9.3 MMBoe in 2014. Our average daily sales volumes increased to 42.1 MMBoe per day in 2015 compared to 25.5 MMBoe per day in 2014. The average NYMEX crude oil and natural gas prices decreased by 47 percent and 40 percent in 2015 and 2014, respectively.

During various times between 2012 and the summer of 2015, our production had been adversely affected by high line pressures in the natural gas gathering facilities in the Wattenberg Field. Such pressures did not materially affect our production during 2016 due to the investment in the midstream capabilities by our midstream providers and a decrease in development activity by certain producers in the Wattenberg Field resulting in more relative capacity being available to deliver our production. In 2016, approximately 90 percent of our production in the Wattenberg Field was delivered from horizontal wells, with the remaining 10 percent coming from vertical wells. The horizontal wells are less prone to issues than the vertical wells in that they are newer and have greater producing capacity and higher formation pressures and therefore tend to be more resilient from periodic gas system pressure issues.

We rely on our third-party midstream service providers to construct compression, gathering and processing facilities to keep pace with our, and the overall field's, production growth. We anticipate gathering system pressures to vary throughout the year, with increases coinciding with the warmer summer months. We, along with other operators in the Wattenberg Field, continue to work closely with our third-party midstream providers in an effort to ensure adequate system capacity going forward as evidenced by a recent commitment of DCP to build additional gathering and processing in the field. This expansion of gathering and processing facilities is expected to improve natural gas gathering pipelines and processing facilities and assist in the control of line pressures in the Wattenberg Field. However, the timing and availability of adequate infrastructure is not within our control and if our midstream provider's construction projects are delayed, we could experience higher line pressures that may negatively impact our ability to fulfill our growth plans. Total system infrastructure needs may also be affected by a number of factors, including potential increases in production from the Wattenberg Field and warmer than expected weather.

Crude Oil, Natural Gas, and NGLs Pricing. Our results of operations depend upon many factors, particularly the price of crude oil, natural gas, and NGLs, and our ability to market our production effectively. Crude oil, natural gas, and NGL prices have a high degree of volatility. While the price of crude oil decreased during the first half of 2016 compared to 2015, prices increased during the second half of 2016 as compared to the first half of the year as the number of U.S. crude oil rigs and inventories declined in the last half of 2015 and into early 2016. Natural gas prices decreased during 2016 compared to 2015, primarily due to domestic oversupply driven by a lack of a normal winter withdrawal cycle in the winter of 2015-2016. We experienced improved NGL pricing towards the end of 2016; however, due to an oversupply of nearly all domestic NGLs products, our average realized sales price for NGLs during most of 2016 reflected the same depressed levels seen during 2015. With the initiation of ethane exports and increased domestic demand for NGLs driven by the completion of petrochemical processing plants, the industry is beginning to see NGL prices trend upward, including in the near term forward market.

Crude Oil. Crude oil pricing is predominately driven by the physical market, supply and demand, the relative strength of the U.S. dollar, financial markets, and national and international politics. In the Wattenberg Field, our crude oil is sold under various purchase contracts with monthly and longer term transportation provisions based on NYMEX pricing, adjusted for differentials. We have entered into commitments ranging in term from one month to over three years to deliver crude oil to competitive markets, resulting in improved overall average deductions in 2016, as noted previously. We continue to pursue various alternatives with respect to oil transportation, particularly in the Wattenberg Field, with a view toward further improving pricing and limiting our use of trucking through delivering greater quantities of our crude oil via pipeline to liquid markets. We began delivering crude oil in accordance with our long term commitment to the White Cliffs pipeline in July 2015. The White Cliffs agreement is one of several we have entered into to facilitate deliveries of a portion of our crude oil to the Cushing, Oklahoma market. In addition, to the White Cliffs agreement described above, we have signed a long-term agreement with Saddle Butte Rockies Midstream, LLC for gathering of crude oil at the wellhead by pipeline from several of our producing pads in the Wattenberg Field, with a view toward minimizing truck traffic, increasing reliability, reducing the overall physical footprint of our well pads, and reducing emissions. We began delivering crude oil into this pipeline during the fourth quarter of 2015 and continued to grow these volumes during 2016.

In the Delaware Basin, our crude oil production is sold at the wellhead and transported via trucks to pipelines that deliver the oil to the Midland, Texas, crude oil market. Given the increased level of activity in the form of acquisitions, leasing, and the increases in rig count in the Delaware Basin over the last six months, we expect the balance between production and pipeline takeaway capacity to tighten during 2017. At the current time, there are pipeline, truck and rail pathways out of the basin, all of which are available to us. We are evaluating near-term and longer-term solutions that contemplate the increased activity levels we expect, as well as our anticipated future production. These may include longer-term sales agreements.

In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual pad based on NYMEX pricing, adjusted for differentials, and is typically transported by the purchasers via truck to local refineries, rail facilities, or barge loading terminals on the Ohio River. To date, we have not experienced any issues with takeaway capacity in this region for our crude oil.

Natural Gas. Natural gas prices vary quite significantly by region and locality, depending upon the distance to markets, availability of pipeline capacity, and supply and demand relationships in that region or locality. The price we receive for our natural gas produced in the Wattenberg Field is based on CIG pricing provisions or local distribution company monthly/daily pricing provisions, adjusted for certain deductions. Our natural gas from the Delaware Basin is sold into the Waha hub and El Paso index markets. Natural gas produced in the Utica Shale is sold based on TETCO M-2 pricing.

Natural Gas Liquids. Our NGL sales are priced based upon the components of the product and are correlated to the price of crude oil. Our price for NGLs produced in the Wattenberg Field is based on a combination of prices from the Conway hub in Kansas and Mt. Belvieu in Texas where this production is marketed. While NGL prices remained low during the majority of 2016, we realized improvements in NGL pricing during the fourth quarter of 2016 and are seeing this improvement continue in early 2017. Given the lack of liquidity in the forward markets, it is unclear if this trend will continue. Delaware Basin NGLs sales are indexed to NYMEX and sold into the Mt. Belvieu, Texas market. The NGLs produced in the Utica Shale are sold based on month-to-month pricing to various markets.

Our crude oil, natural gas, and NGLs sales are recorded under either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the "net-back" method of accounting for natural gas and NGLs, as well as the majority of our crude oil production from the Wattenberg Field, for all commodities in the Delaware Basin, and for crude oil from the Utica Shale as the majority of the purchasers of these commodities also provide transportation, gathering, and processing services. In these situations, the purchaser pays us proceeds based on a percent of the proceeds, or have fixed our sales price at index less a specified deduction. We sell our commodities at the wellhead or what is tantamount to the wellhead in situations where we gather multiple wells into larger pads, and collect a price and recognize revenues based on the wellhead sales price as transportation and processing costs downstream of the wellhead are incurred by the purchaser and therefore embedded in the wellhead price. The "net-back" method results in the recognition of a net sales price that is lower than the indices for which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we earn. We use the "gross" method of accounting for Wattenberg Field crude oil delivered through the White Cliffs and Saddle Butte pipelines, and for natural gas and NGLs sales related to production from the Utica Shale as the purchasers do not provide transportation, gathering or processing services as a function of the price we earn. Rather, we contract separately with the midstream provider for the applicable transport and processing based on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering, and processing expenses. As a result of the White Cliffs and Saddle Butte agreements, during 2016 and 2015, our Wattenberg Field crude oil average sales price increased approximately $1.60 and $0.73, respectively, per barrel, relative to the benchmark price because we recognized the costs for transportation on the White Cliffs and Saddle Butte pipelines as an increase in revenues and transportation expense, rather than as a deduction from revenues.

Lease Operating Expenses

Lease operating expenses were $60.0 million in 2016 compared to $57.0 million in 2015. Due to newer and more horizontal well completions that deliver larger volumes of production per well than older vertical wells, we are seeing the lease operating costs spread over more volume, resulting in lower lease operating cost per Boe. This is reflected in the fact that our per Boe lease operating expense decreased by 27 percent to $2.70 for 2016 from $3.71 for 2015. The $3.0 million increase in the total lease operating expenses in 2016 as compared to 2015 was primarily due to an increase of $3.7 million for increases in wages and employee benefits related to an increase in headcount, including costs for additional contract labor, $1.8 million for additional leased compressors to address line pressures, and an increase of $1.5 million related to lease operating expenses for the acquisitions in the Delaware Basin. These increases were partially offset by a decrease in environmental remediation and regulatory compliance projects of $3.2 million due to a reduction in new remediation projects, and a decrease of $1.4 million related to fewer workover and maintenance related projects. With our entry into the Delaware Basin, we anticipate that our per Boe lease operating cost will be higher initially as we have limited wells and production over which to apply our lease operating costs. With time, we expect that the lease operating costs per Boe in the Delaware Basin will improve.

Lease operating expenses were $57.0 million in 2015 compared to $42.4 million in 2014. The $14.6 million increase in lease operating expenses in 2015 as compared to 2014 was primarily due to an increase of $4.2 million for environmental remediation and regulatory compliance projects due to increases in the number of projects and an increase in per project expenses, an increase of $3.4 million for additional wages and employee benefits primarily due to additional headcount, including costs for additional contract labor, $2.0 million for additional workover and maintenance related projects, $1.4 million for additional compressors to correct high line pressures in the Wattenberg Field, $1.0 million for the increasing number of non-operated wells in the Wattenberg Field, and $0.9 million for additional costs pertaining to water hauling and disposal. Lease operating expenses per Boe decreased significantly to $3.71 for 2015 from $4.56 in 2014, as a result of increased production.

Production Taxes

Production taxes are directly related to crude oil, natural gas, and NGLs sales. Production taxes are comprised of both statutory severance tax rates as well as ad valorem tax rates for the applicable production periods. There are a number of adjustments to the statutory rates based on certain credits that are determined based on activity levels and relative commodity prices from year-to-year. The $13.0 million, or 70 percent, increase in production taxes for 2016 compared to 2015 is primarily related to the 31 percent increase in crude oil, natural gas, and NGLs sales, higher ad valorem mill rates, and an overall higher effective tax rate resulting from a decrease in ad valorem tax credits available from the prior year to offset current year severance taxes, driven by the relatively depressed commodity pricing in 2015. These items resulted in effective production tax rates of 6.3 percent and 4.9 percent in 2016 and 2015, respectively. Similarly, the $7.2 million, or 28 percent, decrease in production taxes for 2015 compared to 2014 is primarily related to the 20 percent decrease in crude oil, natural gas, and NGLs sales.

On a per Boe basis, the increase in rates in 2016 impacted the production tax expense, which increased to $1.42 for 2016 compared to $1.20 for 2015 due to the higher effective tax rate noted above. With the decrease in commodity pricing for 2015, production taxes per Boe decreased to $1.20 for 2015 compared to $2.76 for 2014. These items resulted in effective production tax rates of 4.9 percent and 5.4 percent in 2015 and 2014, respectively.

Transportation, Gathering and Processing Expenses

The $8.3 million, or 81 percent, increase in transportation, gathering, and processing expenses for 2016 compared to 2015 was mainly attributable to the costs associated with the White Cliffs and Saddle Butte pipelines in the Wattenberg Field as we began delivering crude oil on these pipelines in July 2015 and December 2015, respectively. We expect to continue to incur these oil transportation costs pursuant to our long-term firm transportation agreement for 6,600 gross barrels per day. The $5.6 million, or 121 percent, increase in transportation, gathering, and processing expenses for 2015 compared to 2014 was mainly attributable to costs associated with the White Cliffs pipeline. Transportation, gathering, and processing expenses per Boe increased to $0.83 for 2016 compared to $0.66 for 2015 and $0.49 for 2014. By using these pipelines and having the pipelines be able to deliver product to the Cushing, Oklahoma market, we benefit from the liquidity associated with the purchasers' delivery point.

Commodity Price Risk Management, Net

We use commodity derivative instruments to manage fluctuations in crude oil and natural gas prices. We have in place a variety of collars, fixed-price swaps, and basis swaps on a portion of our estimated crude oil and natural gas production. Because we sell all of our crude oil and natural gas production at prices related to the indexes inherent in our underlying derivative instruments, we ultimately realize value related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price value related to our swaps.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments and the change in fair value of unsettled derivatives related to our crude oil and natural gas production. Commodity price risk management, net, does not include derivative transactions related to our gas marketing, which are included in sales from and cost of gas marketing.

Net settlements of commodity derivative instruments are based on the difference between the crude oil, natural gas and natural gas index prices at the settlement date of our commodity derivative instruments compared to the respective strike prices contracted for the settlement months that were established at the time we entered into the commodity derivative transaction. The net change in fair value of unsettled commodity derivatives is comprised of the net value increase or decrease in the beginning-of-period fair value of commodity derivative instruments that settled during the period, and the net change in fair value of unsettled commodity derivatives during the period or from inception of any new contracts entered into during the applicable period. The corresponding impact of settlement of the commodity derivative instruments during the period is included in net settlements for the period as discussed above. The net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil and natural gas forward curves and changes in certain differentials.

The following table presents net settlements and net change in fair value of unsettled commodity derivatives included in commodity price risk management, net:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Commodity price risk management gain (loss), net:			
Net settlements of commodity derivative instruments:			
Crude oil fixed price swaps and collars	$ 165.2	$ 208.9	$ 2.3
Natural gas fixed price swaps and collars	41.9	31.0	(3.7)
Natural gas basis protection swaps	1.0	(1.0)	0.6
Total net settlements of commodity derivative instruments	208.1	238.9	(0.8)
Change in fair value of unsettled commodity derivative instruments:			
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	(220.0)	(186.9)	13.3
Crude oil fixed price swaps and collars	(78.6)	99.3	256.1
Natural gas fixed price swaps and collars	(37.1)	53.3	41.7
Natural gas basis swaps	1.9	(1.4)	—
Net change in fair value of unsettled commodity derivative instruments	(333.8)	(35.7)	311.1
Total commodity price risk management gain (loss), net	$ (125.7)	$ 203.2	$ 310.3

Exploration Expense

The following table presents the major components of exploration expense:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Geological and geophysical costs, including seismic purchases	$ 3.5	$ —	$ —
Operating, personnel and other	1.2	1.1	0.9
Total exploration expense	$ 4.7	$ 1.1	$ 0.9

Geological and geophysical costs. Geological and geophysical costs in 2016 were primarily related to the portion of the purchase of seismic data related to unproved acreage in the Delaware Basin.

Impairment of Properties and Equipment

The following table sets forth the major components of our impairments of properties and equipment expense:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Impairment of proved and unproved properties	$ 5.6	$ 154.6	$ 161.6
Amortization of individually insignificant unproved properties	1.4	7.0	4.4
Land and buildings	3.0	—	0.8
Total impairment of properties and equipment	$ 10.0	$ 161.6	$ 166.8

Due to a significant decline in commodity prices and decreases in our net realized sales prices, we experienced triggering events during 2015 and 2014 that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessments, we recorded impairment charges of $150.3 million and $158.3 million in 2015 and 2014, respectively, to write-down our Utica Shale proved and unproved properties. Of these impairment charges, $24.7 million and $112.6 million were recorded in 2015 and 2014, respectively, to write-down certain capitalized well costs on our Utica Shale proved producing properties. In 2015 and 2014, we also recorded impairment charges of $125.6 million and $45.7 million to write-down our Utica Shale lease acquisition costs. The impairment charges, which are included in the consolidated statements of operations line item impairment of properties and equipment, represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair values. We continued to monitor whether any further impairments were triggered and required measurement throughout 2016 given the continued volatility of commodity prices and the continued capital investment in the development and acquisition of oil and gas properties. No such triggering events occurred during 2016. Impairment charges in 2016 relate to the retirement of certain leases that were no longer part of our development plan and to reflect the fair value of other property and equipment that was held for sale as of December 31, 2016. Future deterioration of commodity prices or other operating circumstances could result in additional impairment charges to our properties and equipment.

Amortization of individually insignificant unproved properties. The decrease in 2016 as compared to 2015 is due to the impairment of leases in 2015, which significantly reduced total lease costs. The increase in 2015 as compared to 2014 was primarily related to a higher number of insignificant leases that were subject to amortization in 2015, primarily in the Utica Shale.

Land and buildings. The impairment charge for 2016 represents the excess of the carrying value over the estimated fair value, less the cost to sell, of a field operating facility in Greeley, Colorado, and 12 acres of land located adjacent to our Bridgeport, West Virginia, regional headquarters. The fair values of these assets were determined based upon estimated future cash flows from unrelated third-party bids.

General and Administrative Expense

General and administrative expense increased $22.5 million, or 25 percent, in 2016 compared to 2015. The increase in cash based general and administrative costs was primarily attributable to $12.2 million of legal and professional fees related to the acquisitions in the Delaware Basin, a $7.7 million increase in payroll and employee benefits due to per capita increases in wages and increases in headcount given the increase in our personnel by nine percent over the course of 2016. Stock-based compensation expense in 2016 and 2015 was $19.5 million and $20.1 million, respectively.

General and administrative expense decreased $33.6 million, or 27 percent, in 2015 compared to 2014. The decrease was primarily attributable to $40.3 million recorded in 2014 in connection with certain partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships and a $1.8 million decrease in costs for legal and other professional services in 2015. The decreases were offset in part by an $8.2 million increase in payroll and employee benefits in 2015, of which $3.3 million was related to stock-based compensation. Stock-based compensation expense in 2015 and 2014 was $20.1 million and $17.5 million, respectively.

Depreciation, Depletion, and Amortization

Crude oil and natural gas properties. During 2016, 2015, and 2014, we invested $396.4 million, $554.3 million and $663.4 million, which is net of the change in accounts payable related to capital expenditures, in the development of our oil and natural gas properties, respectively. We also incurred $1.76 billion to acquire proved reserves during 2016. We did not invest in any acquisitions of proved reserves in 2015 or 2014. DD&A expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $413.1 million, $298.8 million, and $188.5 million in 2016, 2015, and 2014, respectively. The year-over-year change in DD&A expense related to crude oil and natural gas properties were primarily due to the following:

	Year Ended December 31,	
	2016 - 2015	2015 - 2014
	(in millions)	
Increase in production	$ 132.3	$ 123.4
Decrease in weighted-average depreciation, depletion and amortization rates	(18.0)	(13.1)
Total increase in DD&A expense related to crude oil and natural gas properties	$ 114.3	$ 110.3

The following table presents our DD&A expense rates for crude oil and natural gas properties:

	Year Ended December 31,		
Operating Region/Area	2016	2015	2014
		(per Boe)	
Wattenberg Field	$ 19.11	$ 20.13	$ 19.26
Delaware Basin	8.34	—	—
Utica Shale	10.66	10.74	31.19
Total weighted-average	18.63	19.44	20.28

The 2016 rate for the Delaware Basin is related to our acquisitions in the Delaware Basin. The slight decrease in the Wattenberg Field rate for 2016 as compared to 2015 was primarily due to the impact of our 2016 year-end reserves. The decrease in the Utica Shale DD&A expense rates in 2015 relative to 2014 was primarily due to the effect of impairments recorded in 2015 and 2014 to write-down certain capitalized well costs on our Utica Shale proved producing properties.

Provision for Uncollectible Notes Receivable

In the first quarter of 2016, we recorded a provision for uncollectible notes receivable of $44.7 million to impair two third-party notes receivable whose collection was not reasonably assured. Later in 2016, we collected a $0.7 million promissory note and reversed the related provision and allowance for uncollectible notes receivable.

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations ("ARO") for 2016 increased by $0.8 million, or 13 percent, compared to 2015, and increased by $2.9 million, or 84 percent, in 2015 compared to 2014. The increase in 2016 was due to adding new wells and the associated increase in amortization expense. The increase in 2015 was primarily attributable to decreases in the estimated useful life of certain vertical wells in the Wattenberg Field.

Interest Expense

Interest expense increased by approximately $14.4 million in 2016 compared to 2015. The increase is primarily attributable to a $9.3 million charge for the bridge loan commitment related to acquisitions of properties in the Delaware Basin, a $7.4 million increase in interest for the issuance of our 2024 Senior Notes, and a $2.9 million increase in interest expense for the issuance of our 2021 Convertible Notes in September 2016. The increases were partially offset by a $5.1 million decrease in interest expense resulting from the net settlement of our 2016 Convertible Notes in May 2016. The entire $9.3 million of interest expense attributed to the bridge loan facility was expensed in 2016 as the bridge loan was replaced with equity and longer term debt financing.

Interest expense decreased by approximately $0.3 million in 2015 compared to 2014. The decrease is primarily comprised of a $1.6 million decrease attributable to an increase in capitalized interest, offset in part by a $0.9 million increase due to higher average borrowings on our revolving credit facility in 2015.

Interest costs capitalized in 2016, 2015, and 2014 were $4.5 million, $5.1 million, and $3.5 million, respectively.

Provision for Income Taxes

The current income tax benefit (expense) in 2016, 2015, and 2014 was $9.9 million, $(3.1) million, and $(0.5) million, respectively. Current income taxes generally relate to the cash that is paid or recovered for income taxes associated with the applicable period. The remaining portion of the total income tax expense is comprised of deferred income tax expense (benefit), which is a result of differences in the timing of deductions for our GAAP presentation of financial statements and the income tax regulations.

For 2016, 2015, and 2014, the effective income tax rate (the "rate") of 37.4 percent, 35.9 percent, and 39.5 percent on income (loss) from operations differs from the federal statutory tax rate of 35 percent primarily due to state taxes and excess stock compensation benefits, offset by nondeductible expenses that consist primarily of officers' compensation cost and government lobbying expenses.

As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions. We continue to voluntarily participate in the Internal Revenue Service’s ("IRS") Compliance Assurance Program (the "CAP Program") for the 2015, 2016, and 2017 tax years. We have received a full acceptance notice from the IRS for our filed 2015 federal tax return and the IRS's post filing review is complete.

We acquired a net deferred tax liability of $379.9 million in 2016 associated with a lack of tax basis relative to the purchase price of one of the Delaware Basin acquisitions. This has resulted in a material increase in our deferred tax liability on the balance sheet as of December 31, 2016.

There has been increased discussion by the federal government of a potential reduction of the corporate income tax rate and corresponding changes to the tax code. In the event of a change in federal or state income tax rates, the impact of the rate change will be required to be recorded through deferred income tax expense. Should statutory income tax rates decrease, our deferred tax liability would decrease, resulting in deferred tax benefit for the period. If the statutory income tax rates increase, our deferred tax liability would increase resulting in a deferred tax expense.

Discontinued Operations

Appalachian Marcellus Shale Assets. In October 2014, we completed the sale of our entire 50 percent ownership interest in PDCM to an unrelated third-party for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $192.0 million, comprised of approximately $152.8 million in net cash proceeds and a promissory note due in 2020 of approximately $39.0 million. The transaction included the buyer's assumption of our share of the firm transportation commitment related to the assets owned by PDCM, as well as our share of PDCM's natural gas hedging positions in effect at the time. The divestiture resulted in a pre-tax gain of $76.3 million. The divestiture represented a strategic shift in our operations. Accordingly, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the consolidated statements of operations for 2014 and prior periods in the Selected Financial Information disclosures.

Net Income (Loss)/Adjusted Net Income (Loss)

The factors resulting in changes in net loss in 2016 and 2015 compared to net income in 2014 are discussed above. These same reasons similarly impacted adjusted net income (loss), a non-U.S. GAAP financial measure, with the exception of the net change in fair value of unsettled derivatives, adjusted for taxes, of $208.9 million, $22.2 million, and $193.1 million in 2016, 2015, and 2014, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, was $37.0 million, $46.1 million, and $37.7 million in 2016, 2015, and 2014 respectively. See *Reconciliation of Non-U.S. GAAP Financial Measures*, below, for a more detailed discussion of this non-U.S. GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operating activities, our revolving credit facility, proceeds raised in debt, and equity capital market transactions and asset sales. In 2016, our primary sources of liquidity were net cash flows from operating activities of $486.3 million, the net proceeds received from the March 2016 public offering of our common stock of approximately $296.6 million, and the net proceeds from the Securities Issuances of approximately $1.1 billion.

We used a portion of the net proceeds from the March 2016 common stock offering to repay all amounts then outstanding on our revolving credit facility and the principal amount owed upon the maturity of the 2016 Convertible Notes in May 2016 and the remainder for general corporate purposes. The net proceeds from the Securities Issuances were used to fund a portion of the purchase price and related fees for acquisitions in the Delaware Basin and for general corporate purposes.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas, and NGLs. Fluctuations in our operating cash flows are substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we partially manage this volatility through our use of commodity derivative instruments. In 2016 and 2015, net settled commodity derivatives comprised approximately 43 percent and 58 percent, respectively, of our cash flows from operating activities. Based upon our hedge position and assuming year-end forward strip pricing, in 2017 and thereafter our derivatives may not be a significant source of cash flow, and may result in cash outflows in 2017 and 2018. As of December 31, 2016, the fair value of our derivatives was a net liability of $70.0 million. Based on the forward pricing strip at December 31, 2016, we would expect negative net settlements totaling approximately $45 million during 2017.

The covenants under our revolving credit agreement limit the volume of our expected future production that we may hedge. However, we may enter into commodity derivative instruments with future settlement periods of up to sixty months from the date of issuance of the commodity derivative instrument. We do not have minimum hedging requirements associated with our revolving credit facility.

Our net working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and changes in our cash and cash equivalents due to our historical practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility when we have borrowings outstanding. At December 31, 2016, we had a working capital surplus of $129.2 million compared to a surplus of $30.7 million at December 31, 2015. The increase in working capital is primarily the result of an increase of $243.3 million in cash and cash equivalents, the $112.9 million reduction in the current portion of long-term debt due to the settlement of our 2016 Convertible Notes in May 2016, and no current amounts outstanding under our revolving credit facility as of December 31, 2016, partially offset by a negative change in the fair value of our commodity derivative instruments of $264.9 million from 2015 to 2016. The net cash position was a result of the Securities Issuances and our desire to have cash available to fund the portion of the 2017 capital investment program that is expected to exceed operating cash flows.

We ended 2016 with cash and cash equivalents of $244.1 million and availability under our revolving credit facility of $688.3 million, providing for a total liquidity position of $932.4 million, compared to $402.2 million at December 31, 2015. The change in liquidity of $530.2 million, or 131.8 percent, was primarily attributable to:

- net cash flows from operating activities of $486.3 million;
- net proceeds received from the March 2016 public offering of our common stock of approximately $296.6 million;
- net proceeds from the Securities Issuances of approximately $1.1 billion; offset in part by,
- cash outflows for capital investments associated with development, exploration, and acquisition activity of $1.76 billion during 2016; and
- cash payment of approximately $115 million upon the maturity of our Convertible Notes in May 2016.

Based on our expectations of cash flows from operations, our cash and cash equivalent balance and availability under our revolving credit facility, we believe that we have sufficient capital to fund our planned activities during 2017.

In March 2015, we filed an automatic shelf registration statement on Form S-3 with the SEC. Effective upon filing, the shelf provides for the potential sale of an unspecified amount of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants or purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital and to have the flexibility to raise such funds in one or more offerings should we perceive market conditions to be favorable. We have utilized the shelf registration statement to raise capital from time to time, and we may utilize the facility in the future to raise additional capital.

Our revolving credit facility is a borrowing base facility and availability under the facility is subject to redetermination each May and November, based upon a quantification of our proved reserves at each June 30 and December 31, respectively. In September 2016, we entered into a Third Amendment to the Third Amended and Restated Credit Agreement. The amendment, among other things, amended the revolving credit facility to permit the completion of acquisitions in the Delaware Basin and, effective upon closing of the acquisitions, adjusted the interest rate payable on amounts borrowed under the facility, increased the aggregate commitments under the facility from $450 million to $700 million, and reduced our maximum leverage ratio to 4.00:1.00 times as described in more detail below. The maturity date of our revolving credit facility is May 2020. In October 2016, we entered into the Fourth Amendment to the Third Amended and Restated Credit Agreement. The amendment, among other things, reaffirmed our borrowing base at $700 million and, increased the percentage of our future production that we are permitted to hedge. Our borrowing base availability under the revolving credit facility is limited under our 2022 Senior Notes to the greater of $700 million or the calculated value under an Adjusted Consolidated Tangible Net Asset test, as defined.

Our borrowings bear interest at either the LIBOR or prime rate plus an applicable margin, depending on the percentage of the commitment that has been utilized as of December 31, 2016, the applicable margin is 1.25%, and the unused commitment fee is 0.50%.

We had no balance outstanding on our revolving credit facility as of December 31, 2016. As of December 31, 2016, RNG had issued an irrevocable standby letter of credit of approximately $11.7 million in favor of a third-party transportation service provider to secure firm transportation of the natural gas produced by third-party producers for whom we market production in the Appalachian Basin. The letter of credit expires in September 2017 and is automatically extended annually in accordance with the letter of credit's terms and conditions. The letter of credit reduces the amount of available funds under our revolving credit facility by an amount equal to the letter of credit. While we have added and expect to continue to add producing reserves through our drilling operations, the effect of any such reserve additions on our borrowing base could be offset by other factors including, among other things, a prolonged period of depressed commodity prices or regulatory pressure on lenders to reduce their exposure to exploration and production companies.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain: (i) total debt of less than 4.00 times the trailing 12 months earnings before interest, taxes, depreciation, depletion and amortization, change in fair value of unsettled commodity derivatives, exploration expense, gains (losses) on sales of assets and other non-cash, gains (losses) ("EBITDAX"), and (ii) an adjusted current ratio of at least 1.00:1.00. Our adjusted current ratio is adjusted by eliminating the impact on our current assets and liabilities of recording the fair value of crude oil and natural gas commodity derivative instruments. Additionally, available borrowings under our revolving credit facility are added to the current asset calculation and the current portion of our revolving credit facility debt is eliminated from the current liabilities calculation. At December 31, 2016, we were in compliance with all debt covenants with a 2.10 times debt to EBITDAX ratio and a 5.00:1.00 current ratio. We expect to remain in compliance into the foreseeable future.

The indentures governing our 2024 Senior Notes and 2022 Senior Notes contain customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt including limitations as to availability under our revolving credit facility, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. At December 31, 2016, we were in compliance with all covenants and expect to remain in compliance into the foreseeable future.

In January 2017, pursuant to the filing of the supplemental indentures for the 1.25% convertible senior notes due in 2021 ("2021 Convertible Senior Notes"), the 2024 Senior Notes, and the 2022 Senior Notes, our subsidiary PDC Permian, Inc., became a guarantor of the notes.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our commodity derivative positions, operating costs, and general and administrative expenses. Cash flows provided by operating activities increased in 2016 compared to 2015. The $75.2 million increase was primarily due to the increase in crude oil, natural gas, and NGLs sales of $118.7 million. We also realized an increase in the change of funds held for future distribution of $36.5 million, and an increase in the deferral of income taxes of $13.1 million. The increases were partially offset by a decrease in monthly derivative commodity settlements of $30.8 million, and increases in general and administrative expense of $22.5 million, interest expense of $14.4 million, production taxes of $13.0 million and transportation, gathering, and processing expenses of $8.3 million.

Cash flows provided by operating activities increased in 2015 compared to 2014. The $174.4 million increase was primarily due to the increase in normal monthly derivative commodity settlements of $241.0 million and a decrease in general and administrative expense of $33.6 million and production taxes of $7.2 million. The increase was offset by the decrease in crude oil, natural gas, and NGLs sales of $92.7 million and an increase in lease operating costs of $14.6 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $46.0 million in 2016 to $466.8 million, and $170.6 million to $420.8 million in 2015, when compared to the respective prior years. These changes were primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and/or receipts of our assets and liabilities of $19.5 million and $9.7 million in 2016 and 2015, respectively.

Adjusted EBITDA, a non-U.S. GAAP financial measure, decreased by $7.6 million in 2016 to $435.6 million from $443.2 million in 2015, primarily as a result of the provision for uncollectible notes receivable of $44.0 million, the decrease in net settlements from our monthly derivative commodity settlements of $30.8 million, an increase in general and administrative expense of $22.5 million, and a $27.8 million increase in production and exploration expense. The decrease was partially offset by the increase in crude oil, natural gas, and NGLs sales of $118.7 million.

Adjusted EBITDA increased by $78.9 million in 2015 from 2014, primarily as a result of the increase in normal monthly derivative commodity settlements of $241.0 million and a decrease in general and administrative expense of $33.6 million. The increase was partially offset by the decrease in crude oil, natural gas, and NGLs sales of $92.7 million, and an $88.8 million decrease in contribution margins from discontinued operations and a $14.6 million increase in lease operating costs.

Investing Activities. Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to invest significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital markets are not available in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. During 2016, our acquisitions in the Delaware Basin comprised the majority of our cash flows used in investing activities. Net cash used in the Delaware Basin acquisitions was $1.1 billion and we used cash of $436.9 million for our oil and gas operations. Our total cash used in investing activities during 2016 was approximately $1.5 billion. Through July 2016, we ran four automated drilling rigs in the Wattenberg Field. In August 2016, we decreased the number of automated drilling rigs to three in anticipation of higher working interests in wells drilled resulting from an acreage exchange. In the Utica Shale, we drilled and completed five gross (4.5 net) wells, all of which were turned-in-line to sales in 2016. With the closing of our acquisitions in the Delaware Basin, we completed the drilling of two wells that were in-process at closing, spud an additional well, and turned-in-line one well prior to the end of 2016.

Net cash used in investing activities of $604.3 million during 2015 was primarily related to cash utilized for our drilling operations. Net cash used in investing activities of $474.1 million during 2014 was primarily related to cash utilized for our drilling operations of $623.8 million, offset in part by the $152.8 million net cash proceeds received from the sale of our entire 50 percent ownership interest in PDCM.

Financing Activities. Net cash from financing activities in 2016 was primarily related to the $855.1 million of net proceeds received from the issuance of 9.4 million shares of our common stock, $392.2 million of net proceeds from issuance of the 2024 Senior Notes and $193.9 million of net proceeds from issuance of the 2021 Convertible Notes, partially offset by the $115 million payment owed upon the maturity of the 2016 Convertible Notes and net payments of approximately $37.0 million to pay down amounts borrowed under our revolving credit facility.

Net cash from financing activities in 2015 was primarily related to $202.9 million of net proceeds received from the issuance of our common stock in March 2015, partially offset by net payments of approximately $19.0 million to pay down amounts borrowed under our revolving credit facility. Net cash from financing activities in 2014 were primarily comprised of net borrowings under our revolving credit facility of $63.8 million to execute our capital budget.

Contractual Obligations and Contingent Commitments

The following table presents our contractual obligations and contingent commitments as of December 31, 2016:

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in millions)				
Long-term liabilities reflected on the consolidated balance sheet (1)					
Long-term debt (2)	$ 1,100	$ —	$ —	$ 900	$ 200
Commodity derivative contracts (3)	81	54	27	—	—
Capital leases (4)	2	1	1	—	—
Production tax liability	53	24	29	—	—
Asset retirement obligations	93	10	20	22	41
Other liabilities (5)	7	1	1	2	3
	1,336	90	78	924	244
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	537	91	181	169	96
Operating leases	22	3	6	6	7
Firm transportation and processing agreements (8)	187	17	52	49	69
	746	111	239	224	172
Total	$ 2,082	$ 201	$ 317	$ 1,148	$ 416

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(1) Table does not include deferred income tax liability to taxing authorities of $143.5 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) *Amount presented does not agree with the consolidated balance sheets in that it excludes $37.5 million of unamortized debt discount and $18.6 million of unamortized debt issuance costs.*
(3) *Represents our gross liability related to the fair value of derivative positions.*
(4) *Short-term capital lease obligations are included in other accrued expenses on the consolidated balance sheets. Long-term capital lease obligations are included in other liabilities on the consolidated balance sheets.*
(5) *Includes deferred compensation to former executive officers and deferred payments related to firm transportation agreements.*
(6) *Table does not include an undrawn $11.7 million irrevocable standby letter of credit pending issuance to a transportation service provider. Additionally, the table does not include the annual repurchase obligations to investing partners or termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.*
(7) *Amounts presented include $224.4 million to the holders of our 2022 Senior Notes, $188.7 million to the holders of our 2024 Senior Notes, and $115.2 million payable to the holders of our 2021 Convertible Notes. Amounts also include $11.0 million payable to the participating banks in our revolving credit facility, of which interest of $9.0 million is related to unutilized commitments at a rate of 0.38% per annum, and $0.2 million is related to our undrawn letters of credit.*
(8) *Represents our gross commitment which includes volumes produced by us, purchased from third parties and produced by our affiliated partnerships and other third-party working, royalty and overriding royalty interest owners whose volumes we market on their behalf. This includes anticipated and estimated commitments associated with a new gas processing facility by our primary mid-stream provider. The timing of such payments has been estimated and is subject to change based on the completion of construction and the commencing of operations by the midstream provider.*

As the managing general partner of affiliated partnerships, we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

From time to time, we are a party to various legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations, or liquidity.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to business operations and the understanding of our results of operations. This is not a comprehensive list of all of the accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by U.S. GAAP, with no need for our judgment in the application. There are also areas in which our judgment in selecting available alternatives would not produce a materially different result. However, certain of our accounting policies are particularly important to the presentation of our financial position and results of operations and we may use significant judgment in the application. As a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see the footnote titled *Summary of Significant Accounting Policies* to our consolidated financial statements included elsewhere in this report.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves.

Annually, we engage independent petroleum engineers to prepare reserve and economic evaluations of all our properties on a well-by-well basis as of December 31. We adjust our crude oil and natural gas reserves for major acquisitions, new drilling, and divestitures during the year as needed. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering, and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have an effect on our net income (loss).

Exploration costs, including geological and geophysical expenses, the acquisition of seismic data covering unproved acreage, and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but are charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as "suspended well costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from the suspended well status and the proper accounting treatment is applied.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired, or amortized. Unproved crude oil and natural gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to impairment of crude oil and natural gas properties. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms, with the amortization recognized in impairment of crude oil and natural gas properties. The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

We assess our crude oil and natural gas properties for possible impairment upon a triggering event or when circumstances warrant by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. Any impairment in value is charged to impairment of properties and equipment. The estimates of future prices may differ from current market prices of crude oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices, or rising operating costs could result in a triggering event, and therefore, a reduction in undiscounted future net cash flows and an impairment of our crude oil and natural gas properties. Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Crude Oil, Natural Gas, and NGLs Sales Revenue Recognition. Crude oil, natural gas, and NGLs sales are recognized when production is sold to a purchaser at a determinable price, delivery has occurred, rights and responsibility of ownership have transferred and collection of revenue is reasonably assured. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas, and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes and prices received. We receive payment for sales from one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have been immaterial. If a sale is deemed uncollectible, an allowance for doubtful collection is recorded.

Fair Value of Financial Instruments. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Commodity Derivative Financial Instruments. We measure the fair value of our commodity derivative instruments based on a pricing model that utilizes market-based inputs, including but not limited to the contractual price of the underlying position, current market prices, natural gas, and crude oil forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of commodity derivative liabilities and the effect of our counterparties' credit standings on the fair value of commodity derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding commodity derivative position.

We validate our fair value measurement through the review of counterparty statements and other supporting documentation, the determination that the source of the inputs is valid, the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. While we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe our valuation method is appropriate and consistent with those used by other market participants, the use of a different methodology, or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Net settlements on our commodity derivative instruments are initially recorded to accounts receivable or payable, as applicable, and may not be received from or paid to counterparties to our commodity derivative contracts within the same accounting period. Such settlements typically occur the month following the maturity of the commodity derivative instrument. We have evaluated the credit risk of the counterparties holding our commodity derivative assets, which are primarily financial institutions who are also major lenders in our revolving credit facility, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding commodity derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our counterparties on the fair value of our commodity derivative instruments is not significant.

Deferred Income Tax Asset Valuation Allowance. Deferred income tax assets are recognized for deductible temporary differences, net operating loss carry-forwards and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset is not expected to be realized under the preceding criteria, we establish a valuation allowance. The factors which we consider in assessing whether we will realize the value of deferred income tax assets involve judgments and estimates of both amount and timing. The judgments used in applying these policies are based on our evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

Accounting for Business Combinations. We utilize the purchase method to account for acquisitions of businesses and assets. The value of the purchase consideration takes into account the degree to which the consideration is objective and measurable such as cash consideration paid to a seller. With the issuance of equity, restrictions upon the sale of the issued stock are taken into consideration. Pursuant to purchase method accounting, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on appraisals, discounted cash flows, quoted market prices, and estimates by management. When appropriate, we review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value as such sales represent the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped and unproved crude oil and natural gas properties, and other non-crude oil and natural gas properties. To estimate the fair values of these properties, we prepare estimates of crude oil and natural gas reserves. When appropriate, we review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value; for example, the amount at which a willing buyer and seller would enter into an exchange for such properties. We estimate future prices by using the applicable forward pricing strip to apply to our estimate of reserve quantities acquired, and estimates of future operating and development costs, to arrive at an estimate of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted-average cost of capital rate is subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors.

We record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Recent Accounting Standards

See the footnote titled *Summary of Significant Accounting Policies - Recently Adopted Accounting Standards* to our consolidated financial statements included elsewhere in this report.

Reconciliation of Non-U.S. GAAP Financial Measures

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flows earned or incurred from operating activities, without regard to changes in operating assets and liabilities. We believe it is important to consider adjusted cash flows from operations, as well as cash flows from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the related asset or liability was received or paid during the same period. We also use this measure because the timing of cash received from our assets, cash paid to obtain an asset or payment of our obligations has been only a timing issue from one period to the next as we have not had accounts receivable collection problems, nor been unable to purchase assets or pay our obligations.

Adjusted net income (loss). We define adjusted net income (loss) as net income (loss), plus loss on commodity derivatives, less gain on commodity derivatives and net settlements on commodity derivatives, each adjusted for tax effects. We believe it is important to consider adjusted net income (loss), as well as net income (loss). We believe this measure often provides more transparency into our operating trends, such as production, prices, operating costs, net settlements from derivatives and related factors, without regard to changes in our net income (loss) from mark-to-market adjustments resulting from net changes in the fair value of unsettled derivatives. Additionally, other items which we believe are not indicative of future results may be excluded to clearly identify operating trends.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss), plus loss on commodity derivatives, interest expense, net of interest income, income taxes, impairment of properties and equipment, depreciation, depletion, and amortization and accretion of asset retirement obligations, less gain on commodity derivatives and net settlements on commodity derivatives. Adjusted EBITDA is not a measure of financial performance or liquidity under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss), nor as an indicator of cash flows reported in accordance with U.S. GAAP. Adjusted EBITDA includes certain non-cash costs incurred by us and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDA is relevant because it is a measure of our operational and financial performance, as well as a measure of our liquidity, and is used by our management, investors, commercial banks, research analysts, and others that utilize our financial statements to analyze such things as:

- operating performance and return on capital as compared to our peers;

- financial performance of our assets and our valuation without regard to financing methods, capital structure, or historical cost basis;
- ability to generate sufficient cash to service our debt obligations and commitments; and
- viability of acquisition opportunities and capital investment projects, including the related rate of return.

PV-10. We define PV-10 as the estimated present value of the future net cash flows from our proved reserves before income taxes, discounted using a 10 percent discount rate. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts, investors, and other users of our financial statements may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating us and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves.

The following table presents a reconciliation of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Adjusted cash flows from operations:			
Net cash from operating activities	$ 486.3	$ 411.1	$ 236.7
Changes in assets and liabilities	(19.5)	9.7	13.5
Adjusted cash flows from operations	$ 466.8	$ 420.8	$ 250.2
Adjusted net income (loss):			
Net income (loss)	$ (245.9)	$ (68.3)	$ 155.4
(Gain) loss on commodity derivative instruments	125.6	(203.2)	(309.3)
Net settlements on commodity derivative instruments	208.2	239.0	(2.0)
Tax effect of above adjustments	(124.9)	(13.6)	118.2
Adjusted net income (loss)	$ (37.0)	$ (46.1)	$ (37.7)
Net income (loss) to adjusted EBITDA:			
Net income (loss)	$ (245.9)	$ (68.3)	$ 155.4
(Gain) loss on commodity derivative instruments, including net settlements	125.6	(203.2)	(309.3)
Net settlement (gain) loss on commodity derivative instruments	208.2	239.0	(2.0)
Interest expense, net	61.0	42.8	48.6
Income tax expense (benefit)	(147.2)	(38.3)	99.2
Impairment of properties and equipment	10.0	161.6	167.3
Depreciation, depletion and amortization	416.9	303.3	201.7
Accretion of asset retirement obligations	7.0	6.3	3.4
Adjusted EBITDA	$ 435.6	$ 443.2	$ 364.3
Cash from operating activities to adjusted EBITDA:			
Net cash from operating activities	$ 486.3	$ 411.1	$ 236.7
Interest expense, net	61.0	42.8	48.6
Stock-based compensation	(19.5)	(20.1)	(17.5)
Amortization of debt discount and issuance costs	(16.2)	(7.0)	(6.9)
Gain on sale of properties and equipment	—	0.4	76.0
Other	(56.5)	6.3	13.9
Changes in assets and liabilities	(19.5)	9.7	13.5
Adjusted EBITDA	$ 435.6	$ 443.2	$ 364.3

PV-10:

PV-10	$	1,675.0	$	1,337.5	$	3,450.1
Present value of estimated future income tax discounted at 10%		(254.4)		(240.6)		(1,143.6)
Standardized measure of discounted future net cash flows	$	1,420.6	$	1,096.9	$	2,306.5

Amounts above include results from continuing and discontinued operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk, and credit risk. We have established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash and cash equivalents and the interest we pay on borrowings under our revolving credit facility. Our 2021 Convertible Notes, 2024 Senior Notes, and 2022 Senior Notes have fixed rates and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of December 31, 2016, our interest-bearing deposit accounts included money market accounts and checking accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of December 31, 2016 was $208.8 million, with a weighted-average interest rate of 0.3 percent. Based on a sensitivity analysis of our interest bearing deposits as of December 31, 2016 and assuming we had $208.8 million outstanding throughout the period, we estimate that a one percent increase in interest rates would have increased interest income for the twelve months ended December 31, 2016 by approximately $2.1 million.

As of December 31, 2016, we had no outstanding balance on our revolving credit facility.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas, and NGLs. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. These instruments help us predict with greater certainty the effective crude oil and natural gas prices we will receive for our hedged production. We believe that our commodity derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our commodity derivative positions related to crude oil and natural gas sales in effect as of December 31, 2016:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
		Weighted-Average Contract Price						
Commodity/ Index/ Maturity Period	Quantity*(Gas - BBtu Oil - MBbls)*	Floors	Ceilings	Quantity*(Gas - BBtu Oil - MBbls)*	Weighted-Average Contract Price	Quantity *(BBtu)*	Weighted-Average Contract Price	Fair Value December 31, 2016 (1) *(in millions)*
Crude Oil								
NYMEX								
2017	2,464	$ 49.54	$ 62.32	6,002	$ 49.14	—	$ —	$ (44.3)
2018	1,512	41.85	54.31	3,364	53.25	—	—	(19.1)
Total Crude Oil	3,976			9,366		—	—	$ (63.4)
Natural Gas								
NYMEX								
2017	7,920	$ 3.59	$ 4.13	27,290	$ 3.55	28,116	$ (0.29)	$ (0.5)
2018	1,230	3.00	3.67	45,280	2.94	18,200	(0.29)	(6.1)
Total Natural Gas	9,150			72,570		46,316		$ (6.6)
Total Crude Oil and Natural Gas								**$ (70.0)**

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(1) Approximately 44 percent of the fair value of our commodity derivative assets and 18 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).

Our realized prices vary regionally based on local market differentials and our transportation agreements. The following table presents average market index prices for crude oil and natural gas for the periods identified, as well as the average sales prices we realized for our crude oil, natural gas, and NGLs production:

	Year Ended December 31,	
	2016	2015
Average Index Price:		
Crude oil (per Bbl)		
NYMEX	$ 43.32	$ 48.80
Natural gas (per MMBtu)		
NYMEX	$ 2.46	$ 2.66
Average Sales Price Realized:		
Excluding net settlements on commodity derivatives		
Crude oil (per Bbl)	$ 39.96	$ 40.14
Natural gas (per Mcf)	1.77	2.04
NGLs (per Bbl)	11.80	10.72

Based on a sensitivity analysis as of December 31, 2016, it was estimated that a 10 percent increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have commodity derivatives in place would have resulted in a decrease in the fair value of our derivative positions of $87.0 million, whereas a 10 percent decrease in prices would have resulted in an increase in fair value of $86.7 million.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to significant credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We monitor the creditworthiness of significant counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure performance by our counterparties.

Our Oil and Gas Exploration and Production segment's crude oil, natural gas, and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers.

Amounts due to our Gas Marketing segment are from a diverse group of entities, including major upstream and midstream energy companies, financial institutions, and end-users in various industries. The underlying operations of these entities are however geographically concentrated in the same region, which increases the credit risk associated with this segment. As natural gas prices continue to remain depressed, certain third-party producers relating to our Gas Marketing segment are continuing to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. We have initiated several legal actions for breach of contract, collection and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in two default judgments. We expect this trend to continue for this segment.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our commodity derivative financial instruments. See the footnote titled *Commodity Derivative Financial Instruments* to our consolidated financial statements included elsewhere in this report for more detail on our commodity derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2016, it does not consider those exposures or positions which could arise after that date. Our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements, Financial Statement Schedule and Supplemental Information

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PDC Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows, and equity present fairly, in all material respects, the financial position of PDC Energy, Inc. and its subsidiaries at December 31, 2016 and December 31, 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. In addition, in our opinion, the financial statement schedule for each of the three years ended December 31, 2016, appearing under Item 8, presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

As described in Management’s Annual Report on Internal Control over Financial Reporting, management has excluded certain Delaware Basin acquisitions from their assessment of internal control over financial reporting as of December 31, 2016, because they were acquired by the Company in a purchase business combination during 2016. We have also excluded these acquisitions from our audit of internal control over financial reporting. The acquisitions are wholly owned subsidiaries whose total assets and total revenues represent 11% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

/s/PricewaterhouseCoopers LLP

Denver, Colorado
February 28, 2017

PDC ENERGY, INC.
Consolidated Balance Sheets
(in thousands, except share and per share data)

As of December 31,	2016	2015
Assets		
Current assets:		
Cash and cash equivalents	$ 244,100	$ 850
Accounts receivable, net	143,392	104,274
Fair value of derivatives	8,791	221,659
Prepaid expenses and other current assets	3,542	5,266
Total current assets	399,825	332,049
Properties and equipment, net	4,008,266	1,940,552
Fair value of derivatives	2,386	44,387
Goodwill	62,041	—
Other assets	13,324	53,555
Total Assets	$ 4,485,842	$ 2,370,543
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 66,322	$ 92,613
Production tax liability	24,767	26,524
Fair value of derivatives	53,595	1,595
Funds held for distribution	71,339	29,894
Current portion of long-term debt	—	112,940
Accrued interest payable	15,930	9,057
Other accrued expenses	38,625	28,709
Total current liabilities	270,578	301,332
Long-term debt	1,043,954	529,437
Deferred income taxes	400,867	143,452
Asset retirement obligations	82,612	84,032
Fair value of derivatives	27,595	695
Other liabilities	37,482	24,398
Total liabilities	1,863,088	1,083,346
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 65,704,568 and 40,174,776 issued as of December 31, 2016 and 2015, respectively	657	402
Additional paid-in capital	2,489,557	907,382
Retained earnings	134,208	380,422
Treasury shares - at cost, 28,763 and 20,220 as of December 31, 2016 and 2015, respectively	(1,668)	(1,009)
Total stockholders' equity	2,622,754	1,287,197
Total Liabilities and Stockholders' Equity	$ 4,485,842	$ 2,370,543

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Operations
(in thousands, except per share data)

Year Ended December 31,	2016	2015	2014
Revenues			
Crude oil, natural gas, and NGLs sales	$ 497,353	$ 378,713	$ 471,413
Sales from gas marketing	8,725	10,920	71,571
Commodity price risk management gain (loss), net of settlements	(125,681)	203,183	310,304
Other income	2,518	2,510	2,919
Total revenues	382,915	595,326	856,207
Costs, expenses and other			
Lease operating expenses	59,950	56,992	42,402
Production taxes	31,410	18,443	25,615
Transportation, gathering and processing expenses	18,415	10,151	4,592
Cost of gas marketing	10,193	11,717	72,015
Exploration expense	4,669	1,102	947
Impairment of properties and equipment	9,973	161,620	166,847
General and administrative expense	112,470	89,959	123,559
Depreciation, depletion and amortization	416,874	303,258	192,528
Provision for uncollectible notes receivable	44,038	—	—
Accretion of asset retirement obligations	7,080	6,293	3,415
(Gain) loss on sale of properties and equipment	(43)	(385)	507
Total cost, expenses and other	715,029	659,150	632,427
Income (loss) from operations	(332,114)	(63,824)	223,780
Interest expense	(61,972)	(47,571)	(47,842)
Interest income	963	4,807	1,290
Income (loss) before income taxes	(393,123)	(106,588)	177,228
Income tax benefit (expense)	147,195	38,308	(69,967)
Income (loss) from continuing operations	(245,928)	(68,280)	107,261
Income from discontinued operations, net of tax	—	—	48,174
Net income (loss)	$ (245,928)	$ (68,280)	$ 155,435
Earnings per share:			
Basic			
Income (loss) from continuing operations	$ (5.01)	$ (1.74)	$ 3.00
Income from discontinued operations, net of tax	—	—	1.34
Basic	$ (5.01)	$ (1.74)	$ 4.34
Diluted			
Income (loss) from continuing operations	$ (5.01)	$ (1.74)	$ 2.93
Income from discontinued operations, net of tax	—	—	1.31
Diluted	$ (5.01)	$ (1.74)	$ 4.24
Weighted-average common shares outstanding:			
Basic	49,052	39,153	35,784
Diluted	49,052	39,153	36,678

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2016	2015	2014
Cash flows from operating activities:			
Net income (loss)	$ (245,928)	$ (68,280)	$ 155,435
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled commodity derivatives	333,770	35,791	(311,281)
Depreciation, depletion and amortization	416,874	303,258	201,656
Provision for uncollectible notes receivable	44,038	—	—
Impairment of properties and equipment	9,973	161,620	167,280
Accretion of asset retirement obligation	7,080	6,293	3,455
Stock-based compensation	19,502	20,068	17,518
Excess tax benefits from stock-based compensation	—	(1,361)	(1,999)
Gain from sale of properties and equipment	(43)	(385)	(75,972)
Amortization of debt discount and issuance costs	16,167	7,040	6,938
Deferred income taxes	(137,249)	(41,415)	88,474
Other	2,603	(1,855)	(1,329)
Total adjustments to net income (loss) to reconcile to net cash from operating activities:	712,715	489,054	94,740
Changes in assets and liabilities:			
Accounts receivable	(32,627)	24,769	(34,598)
Other assets	2,303	(2,264)	(3,296)
Restricted cash	—	46	2,214
Production tax liability	9,223	(1,629)	3,358
Accounts payable and accrued expenses	(162)	(30,310)	21,453
Funds held for future distribution	36,510	2,699	(4,372)
Other liabilities	4,229	(3,012)	1,755
Total changes in assets and liabilities	19,476	(9,701)	(13,486)
Net cash from operating activities	486,263	411,073	236,689
Cash flows from investing activities:			
Capital expenditures for development of crude oil and natural gas properties	(436,884)	(599,546)	(623,750)
Capital expenditures for other properties and equipment	(3,464)	(5,122)	(4,842)
Acquisition of crude oil and natural gas properties, net of cash acquired	(1,073,723)	—	—
Proceeds from sale of properties and equipment, net	4,945	405	154,457
Net cash from investing activities	(1,509,126)	(604,263)	(474,135)
Cash flows from financing activities:			
Proceeds from sale of equity, net of issuance costs	855,074	202,851	—
Proceeds from senior notes, net of issuance costs	392,172	—	—
Proceeds from convertible senior notes, net of issuance costs	193,935	—	—
Proceeds from revolving credit facility	85,000	397,000	263,750
Repayment of revolving credit facility	(122,000)	(416,000)	(200,000)
Redemption of convertible notes	(115,000)	—	—
Payment of debt issuance costs	(15,556)	(974)	(88)
Excess tax benefits from stock-based compensation	—	1,361	1,999
Purchase of treasury shares	(6,935)	(6,056)	(5,392)
Other	(577)	(208)	—
Net cash from financing activities	1,266,113	177,974	60,269

Net change in cash and cash equivalents	243,250	(15,216)	(177,177)
Cash and cash equivalents, beginning of year	850	16,066	193,243
Cash and cash equivalents, end of year	$ 244,100	$ 850	$ 16,066
Supplemental cash flow information:			
Cash payments for:			
Interest, net of capitalized interest	$ 43,406	$ 45,642	$ 46,809
Income taxes, net of refunds	167	10,049	1,800
Non-cash investing activities:			
Issuance of common stock for acquisition of crude oil and natural gas properties related to Delaware Basin acquisition	690,702	—	—
Change in accounts payable related to capital expenditures	(40,448)	(45,230)	39,667
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposal	4,894	14,030	33,250
Change in other assets related to sale of properties and equipment	—	—	39,048
Purchase of properties and equipment under capital leases	1,404	1,601	—

See footnote titled *Business Combinations* for non-cash transactions related to our acquisitions.

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Equity
(in thousands, except share data)

	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balances, January 1, 2014	35,675,656	$ 357	$ 674,211	(5,508)	$ (241)	$ 293,267	$ 967,594
Net income	—	—	—	—	—	155,435	155,435
Purchase of treasury shares	—	—	—	(97,646)	(5,392)	—	(5,392)
Issuance of treasury shares	—	—	(4,817)	83,208	4,817	—	—
Retirement of treasury shares	(703)	—	(35)	703	35	—	—
Non-employee directors' deferred compensation plan	—	—	—	(2,400)	(130)	—	(130)
Issuance of stock awards, net of forfeitures	253,032	2	—	—	—	—	2
Stock-based compensation expense, including tax impact	—	—	19,850	—	—	—	19,850
Balances, December 31, 2014	35,927,985	$ 359	$ 689,209	(21,643)	$ (911)	$ 448,702	$ 1,137,359
Net loss	—	—	—	—	—	(68,280)	(68,280)
Issuance pursuant to sale of equity	4,002,000	40	202,811	—	—	—	202,851
Purchase of treasury shares	—	—	—	(120,864)	(6,055)	—	(6,055)
Issuance of treasury shares	—		(6,206)	127,159	6,206	—	—
Non-employee directors' deferred compensation plan	—	—	—	(4,872)	(249)	—	(249)
Issuance of stock awards, net of forfeitures	237,071	3	—	—	—	—	3
Exercise of stock options	7,720	—	—	—	—	—	—
Stock-based compensation expense, including tax impact	—	—	21,568	—	—	—	21,568
Balances, December 31, 2015	40,174,776	$ 402	$ 907,382	(20,220)	$ (1,009)	$ 380,422	$ 1,287,197
Net loss	—	—	—	—	—	(245,928)	(245,928)
Issuance pursuant to acquisition	9,386,768	94	690,608	—	—	—	690,702
Issuance pursuant to sale of equity	15,007,500	150	854,933	—	—	—	855,083
Issuance pursuant to note conversion	792,406	8	(8)	—	—	—	—
Convertible debt discount, net of issuance costs and tax	—	—	23,518	—	—	—	23,518
Purchase of treasury shares	—	—	—	(116,085)	(6,935)	—	(6,935)
Issuance of treasury shares	(114,697)	—	(6,661)	114,697	6,661	—	—
Non-employee directors' deferred compensation plan	—	—	—	(7,155)	(385)	—	(385)
Issuance of stock awards, net of forfeitures	411,731	3	(3)	—	—	—	—
Exercise of stock options	46,084	—	—	—	—	—	—
Stock-based compensation expense	—	—	19,502	—	—	—	19,502
Adoption of updated stock-based compensation accounting	—	—	286	—	—	(286)	—
Balances, December 31, 2016	65,704,568	$ 657	$ 2,489,557	(28,763)	$ (1,668)	$ 134,208	$ 2,622,754

See accompanying Notes to Consolidated Financial Statements

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. ("PDC", the "Company," "we," "us," or "our") is a domestic independent exploration and production company that acquires, produces, develops, and explores for crude oil, natural gas, and NGLs, with primary operations in the Wattenberg Field in Colorado, the Utica Shale in southeastern Ohio and, beginning in December 2016, the Delaware Basin in Reeves and Culberson Counties, Texas. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays, our Delaware Basin operations are currently focused in the Wolfcamp zones, and our Ohio operations are focused in the Utica Shale play. As of December 31, 2016, we owned an interest in approximately 2,900 productive gross wells. We are engaged in two business segments: The Oil and Gas Exploration and Production Segment and the Gas Marketing Segment. In October 2014, we sold our entire 50 percent ownership interest in our joint venture, PDCM, to an unrelated third-party.

The audited consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries PDC Permian, Inc. and Riley Natural Gas ("RNG"), our proportionate share of our four affiliated partnerships and, for the information presented covering the year ended December 31, 2014, our proportionate share of PDCM. All material intercompany accounts and transactions have been eliminated in consolidation.

The preparation of our consolidated financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to our consolidated financial statements include estimates of crude oil, natural gas and NGLs sales revenue; crude oil, natural gas, and NGLs reserves; estimates of unpaid revenues and unbilled costs; future cash flows from crude oil and natural gas properties; valuation of commodity derivative instruments; impairment of proved and unproved properties; valuation and allocations of purchased businesses and assets; estimates of fair value of our fixed rate debt instruments; and valuation of deferred income tax assets.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents.

Derivative Financial Instruments. We are exposed to the effect of market fluctuations in the prices of crude oil, natural gas, and NGLs. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. Our policy and our revolving credit facility prohibit the use of crude oil and natural gas derivative instruments for speculative purposes.

All derivative assets and liabilities are recorded on our consolidated balance sheets at fair value. We have elected not to designate any of our commodity derivative instruments as cash flow hedges. Accordingly, changes in the fair value of our commodity derivative instruments are recorded in the consolidated statements of operations. Classification of net settlements resulting from maturities and changes in fair value of unsettled commodity derivatives depends on the purpose for issuing or holding the derivative. Net settlements and changes in the fair value of commodity derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Net settlements and changes in the fair value of commodity derivative instruments related to our Gas Marketing segment are recorded in sales from and cost of gas marketing. The consolidated statements of cash flows reflects the net settlement of commodity derivative instruments in operating cash flows.

The calculation of the commodity derivative instrument's fair value is performed internally and, while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Properties and Equipment. Significant accounting polices related to our properties and equipment are discussed below.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves. We have determined that we have three units-of-production fields which are the Wattenberg Field, the Delaware Basin, and the Utica Shale. In making these conclusions we consider the geographic concentration, operating similarities within the areas, geologic considerations, and common cost environments in these areas. We calculate quarterly depreciation, depletion, and amortization ("DD&A") expense by using our estimated prior period-end reserves as the denominator, with the exception of our fourth quarter where we use the year-end reserve estimate adjusted to add back fourth quarter production. Upon the sale or retirement of significant portions of or complete fields of depreciable or depletable property, the net book value thereof, less proceeds or salvage value, is recognized in the consolidated statements of operations as a gain or loss. Upon the sale of individual wells or a portion of a field, the proceeds are credited to accumulated DD&A.

Exploration costs, including geological and geophysical expenses, seismic costs on unproved leasehold, and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but charged to expense if the well is determined to be economically nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as we have found a sufficient quantity of reserves to justify completion as a producing well, we are making sufficient progress assessing our reserves and economic and operating viability, or we have not made sufficient progress to allow for final determination of productivity. If an in-progress exploratory well is found to be economically unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as "suspended well costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time we are able to make a final determination of a well’s productive status, the well is removed from suspended well status and the proper accounting treatment is recorded.

Proved Property Impairment. Upon a triggering event and when general industry conditions warrant review, we assess our producing crude oil and natural gas properties for possible impairment by comparing net capitalized costs, or carrying value, to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of crude oil, natural gas, and NGLs. Certain events, including but not limited to downward revisions in estimates to our reserve quantities, expectations of falling commodity prices, or rising operating costs, could result in a triggering event and, therefore, a possible impairment of our proved crude oil and natural gas properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a future discounted cash flows analysis and is measured by the amount by which the net capitalized costs exceed their fair value. Impairments are included in the consolidated statements of operations line item impairment of properties and equipment, with a corresponding impact on accumulated DD&A.

Unproved Property Impairment. The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired, or amortized. Unproved crude oil and natural gas properties with individually significant acquisition costs are periodically assessed for impairment. Unproved crude oil and natural gas properties which are not individually significant are amortized, by field, based on our historical experience, acquisition dates, and average lease terms. Impairment and amortization charges related to unproved crude oil and natural gas properties are charged to the consolidated statements of operations line item impairment of properties and equipment.

Other Property and Equipment. Other property and equipment is carried at cost. Depreciation is provided principally on the straight-line method over the assets' estimated useful lives. We review these long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of the asset exceeds our estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset. Impairment and amortization charges related to other property and equipment are charged to the consolidated statements of operations line item impairment of properties and equipment.

The following table presents the estimated useful lives of our other property and equipment:

Transportation, pipeline, and other equipment	2 - 30 years
Buildings	20 - 40 years

Maintenance and repair costs on other property and equipment are charged to expense as incurred. Major renewals and improvements are capitalized and depreciated over the remaining useful life of the asset. Upon the sale or other disposition of assets, the cost and related accumulated DD&A are removed from the accounts, the proceeds are applied thereto and any resulting gain or loss is reflected in income. Total depreciation expense related to other property and equipment was $3.8 million, $4.5 million, and $4.1 million in 2016, 2015, and 2014, respectively.

Capitalized Interest. Interest costs are capitalized as part of the historical cost of acquiring assets. Investments in unproved crude oil and natural gas properties and major development projects, on which DD&A is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready to be placed into service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our debt outstanding by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is placed into service, we begin amortizing the related capitalized interest over the useful life of the asset. Capitalized interest totaled $4.5 million, $5.1 million, and $3.5 million in 2016, 2015, and 2014, respectively.

Goodwill. Goodwill represents the residual value of purchase price over net tangible and identifiable intangible assets of an acquired business and is stated at cost. Goodwill is not amortized; rather it is assessed annually for impairment, or more frequently if any event indicates that the carrying amount of goodwill may be impaired.

Assets Held for Sale and Discontinued Operations. Assets held for sale are valued at the lower of their carrying amount or estimated fair value, less costs to sell. If the carrying amount of the assets exceeds their estimated fair value, an impairment loss is recognized. Fair values are estimated using accepted valuation techniques such as a discounted cash flow model, valuations performed by third parties, earnings multiples, or indicative bids, when available. Management considers historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected in the consolidated financial statements. DD&A expense is not recorded on assets to be divested once they are classified as held for sale. Assets classified as held for sale are expected to be disposed of within one year. Assets to be divested are classified in the consolidated financial statements as held for sale and the activities of assets to be divested are classified either as discontinued operations or continuing operations. Assets held for sale of $5.3 million as of December 31, 2016, represents the fair value of field office facilities and a parcel of land. Assets held for sale of $2.9 million as of December 31, 2015, represents the fair value of a parcel of land. These amounts are included in properties and equipment, net on our consolidated balance sheets.

For assets classified as discontinued operations, the results of operations are reclassified from their historical presentation to discontinued operations on the consolidated statements of operations for all periods presented. The gains or losses associated with these divested assets are recorded in discontinued operations on the consolidated statements of operations. For businesses classified as held for sale that do not qualify for discontinued operations treatment, the results of operations continue to be reported in continuing operations.

Production Tax Liability. Production tax liability represents estimated taxes, primarily severance, ad valorem, and property taxes, to be paid to the states and counties in which we produce crude oil, natural gas, and NGLs, including the production of our affiliated partnerships. Our share of these taxes is expensed and included in the statement of operations line item production taxes. Affiliated partnerships' share, not owned by us, is recognized as a receivable in accounts receivable affiliates on the consolidated balance sheets. The long-term portion of the production tax liability is included in other liabilities on the consolidated balance sheets and was $29.0 million and $19.0 million in December 31, 2016 and 2015, respectively.

Income Taxes. We account for income taxes under the asset and liability method. We recognize deferred tax assets and liabilities for the future tax consequences attributable to operating loss and credit carryforwards and differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred tax assets will not be realized, we record a valuation allowance, thereby reducing the deferred tax assets to what we consider realizable. As of December 31, 2016 and 2015, we had no valuation allowance.

Debt Issuance Costs. Debt issuance costs are capitalized and amortized over the life of the respective borrowings using the effective interest method. Debt issuance costs for the 2021 Convertible Notes, the 2024 Senior Notes, and the 2022 Senior Notes are included in long-term debt on the consolidated balance sheets and the debt issuance costs for the revolving credit facility are included in other accrued expenses on the consolidated balance sheets.

Asset Retirement Obligations. We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the related well is completed. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the associated long-lived asset by the same amount as the liability. Over time, the liability is accreted for the change in the present value. The initial capitalized cost, net of salvage value, is depleted over the useful life of the related asset through a charge to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from changes in retirement costs or the estimated timing of settling asset retirement obligations.

Treasury Shares. We record treasury share purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders’ equity in the consolidated balance sheets. When we retire treasury shares, we charge any excess of cost over the par value entirely to additional paid-in-capital ("APIC"), to the extent we have amounts in APIC, with any remaining excess cost being charged to retained earnings.

Revenue Recognition. Significant accounting polices related to our revenue recognition are discussed below.

Crude oil, natural gas, and NGLs sales. Crude oil, natural gas, and NGLs revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, rights and responsibility of ownership have transferred, and collection of revenue is reasonably assured. Our crude oil, natural gas, and NGLs sales are recorded under either the "net-back" or "gross" method of accounting, depending upon the transportation, gathering or processing method used. We use the net-back method of accounting for a portion of our crude oil production in the Wattenberg Field and for substantially all crude oil production in the Delaware Basin and the Utica Shale, as well as natural gas and NGLs from the Delaware Basin and the Wattenberg Field as the majority of the purchasers of these commodities also provide transportation, gathering, and processing services. We sell our commodities at the wellhead and collect a price and recognize revenues based on the wellhead sales price as transportation and processing costs downstream of the wellhead are incurred by the purchaser and reflected in the wellhead price. The net-back method results in the recognition of a sales price that is below the indices for which the production is based. We use the gross method of accounting for Wattenberg Field crude oil delivered through the White Cliffs and Saddle Butte pipelines and for natural gas and NGLs sales related to production from the Utica Shale as the purchasers do not provide transportation, gathering, or processing services. Under this method, we recognize revenues based on the gross selling price.

Gas marketing. Gas marketing is reported on the gross method of accounting, based on the nature of the agreements between our gas marketing subsidiary, RNG, suppliers, and customers. RNG purchases gas from many small producers and bundles the gas together for a price advantage to sell in larger amounts to purchasers of gas. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Gas marketing revenues and expenses reflect the full cost and revenue of those transactions because RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the net settlements and net change in fair value of unsettled commodity derivatives of the RNG commodity-based derivative transactions for gas marketing are included in sales from or cost of gas marketing, as applicable.

Accounting for Business Combinations. We utilize the purchase method to account for acquisitions of businesses and assets. Pursuant to purchase method accounting, we allocate the cost of the acquisition to assets acquired and liabilities assumed based upon respective fair values as of the acquisition date. The purchase price allocations are based upon appraisals, discounted cash flows, quoted market prices, and estimates by management, which are Level 3 inputs. When appropriate, we review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value; for example, the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped, unproved crude oil and natural gas properties, and other non-crude oil and natural gas properties. To estimate the fair value of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices by using the applicable forward pricing strip to apply to our estimate of reserve quantities acquired, and estimates of future operating and development costs, to arrive at an estimate of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted-average cost of capital rate is subject to additional project-specific risk factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors. Additionally, for acquisitions with significant unproved properties, we complete an analysis of comparable purchased properties to determine an estimation of fair value.

We record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Stock-Based Compensation. Stock-based compensation is recognized in our financial statements based on the grant-date fair value of the equity instrument awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in crude oil and natural gas exploration and development activities, such amounts may be capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the related cost and expense line item in the consolidated statements of operations. No amounts for stock-based compensation were capitalized in 2016, 2015, or 2014.

Credit Risk and Allowance for Doubtful Accounts. Inherent to our industry is the concentration of crude oil, natural gas, and NGLs sales to a limited number of customers. This concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices, or other conditions. We record an allowance for doubtful accounts representing our best estimate of probable losses from our existing accounts receivable. In making our estimate, we consider, among other things, our historical write-offs, and overall creditworthiness of our customers. Further, consideration is given to well production data for receivables related to well operations.

Recently Adopted Accounting Standards.

In August 2014, the FASB issued a new standard related to the disclosure of uncertainties about an entity's ability to continue as a going concern. The new standard requires management to assess an entity's ability to continue as a going concern at the end of every reporting period and to provide related footnote disclosures in certain circumstances. The new standard will be effective for all entities in the first annual period ending after December 15, 2016, with early adoption permitted. We early adopted this standard in the fourth quarter of 2016. Adoption of this standard did not have an impact on our consolidated financial statements or related disclosures.

In March 2016, the FASB issued an accounting update on stock-based compensation that is intended to simplify several aspects of the accounting for employee share-based payment award transactions. Areas of simplification include income tax consequences, classification of the awards as either equity or liabilities and the classification on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2016, and interim periods within those years, with early adoption permitted. We early adopted this standard in the fourth quarter of 2016.

- The primary impact of the adoption was the recognition of excess tax benefits in our provision for income taxes rather than additional paid-in capital, as well as the adjustment in stock-based compensation expense as a result of our changes in forfeiture policy. The new guidance eliminates the requirement to delay the recognition of excess tax benefits until it reduces current taxes payable. We adopted this change on a prospective basis, and recorded unrecognized excess tax benefits amounting to $1.5 million, which increased retained earnings in the fourth quarter of 2016.
- The new guidance also requires us to record, subsequent to the adoption, excess tax benefits and tax deficiencies in the period they occur. Prior to the adoption, the excess tax benefits would have been recorded as APIC. This change could create future volatility in our effective tax rate depending upon the amount of exercise or vesting activity from our stock awards. Under the new guidance,

we have elected to change our policy and have started to recognize forfeitures of awards as they occur. The change in forfeiture policy was adopted using a modified retrospective transition method. We recorded a cumulative-effect adjustment to decrease retained earnings by $0.3 million upon transition on January 1, 2016, and an increase of stock-based compensation of $0.1 million during the fourth quarter of 2016. Per the guidance in the accounting standard update, the adjustment to stock-based compensation should be recorded on a retrospective basis. Our adjustment was not material to our condensed consolidated financial statements, therefore, we recorded the entire adjustment in the fourth quarter of 2016.

- The amendment to the minimum statutory withholding tax requirements was adopted on a modified retrospective basis. The adoption had no impact on retained earnings.
- In addition, we adopted the presentation of taxes paid related to the net share settlement as a financing activity on the statement of cash flows on a retrospective basis. Adoption had no impact to any of the periods presented in our consolidated cash flows statements since such cash flows have historically been presented as a financing activity.

Recently Issued Accounting Standards.

In May 2014, the FASB and the International Accounting Standards Board issued their converged standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (1) identify the contract with the customer, (2) identify the separate performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to separate performance obligations and (5) recognize revenue when (or as) each performance obligation is satisfied. In March 2016, the FASB issued an update to the standard intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations when recognizing revenue. In December 2016, the FASB issued technical corrections and improvements to the standard. The revenue standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The revenue standard can be adopted under the full retrospective method or simplified transition method. Entities are permitted to adopt the revenue standard early, beginning with annual reporting periods after December 15, 2016. We are in the process of assessing potential impacts of the new standard on our existing revenue recognition criteria, as well as on related revenue disclosures.

In February 2016, the FASB issued an accounting update aimed at increasing the transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about related leasing arrangements. For leases with terms of more than 12 months, the accounting update requires lessees to recognize a right-of-use asset and lease liability for its right to use the underlying asset and the corresponding lease obligation. Both the lease asset and liability will initially be measured at the present value of the future minimum lease payments over the lease term. Subsequent measurement, including the presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those years, with early adoption permitted, and is to be applied as of the beginning of the earliest period presented using a modified retrospective approach. We are in the process of assessing the impact these changes may have on our consolidated financial statements.

In August 2016, the FASB issued an accounting update on statements of cash flows to address diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our consolidated financial statements.

In November 2016, the FASB issued an accounting update on statements of cash flows to address diversity in practice in the classification and presentation of changes in restricted cash. The accounting update requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash or restricted cash equivalents should be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period amounts shown on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. This is an expansive set of revisions to the cash flow presentation standards, but at this time we do not believe that these changes will impact our consolidated financial statements.

NOTE 3 - BUSINESS COMBINATION

Delaware Basin Acquisition completed December 6, 2016. On December 6, 2016, we closed on an acquisition which has been accounted for as a business combination. The transaction was for the purchase of approximately 57,900 net acres, approximately 30 wells and related midstream infrastructure in Reeves and Culberson Counties, Texas, for an aggregate consideration to the sellers of approximately $1.64 billion, comprised of approximately $952.1 million in cash, including the repayment of $40.0 million of debt from the seller at closing and other purchase price adjustments, and 9.4 million shares of our common stock valued at approximately $690.7 million at the time the acquisition closed.
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The details of the purchase price and the preliminary allocation of the purchase price for the first transaction are presented below (in thousands):

	Year Ended December 31, 2016
Acquisition costs:	
Cash, net of cash acquired	$ 912,142
Retirement of seller's debt	40,000
Total cash consideration	952,142
Common stock, 9.4 million shares	690,702
Other purchase price adjustments	1,026
Total acquisition costs	$ 1,643,870
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$ 8,201
Crude oil and natural gas properties - proved	216,000
Crude oil and natural gas properties - unproved	1,721,334
Infrastructure, pipeline, and other	32,590
Construction in progress	12,148
Goodwill	62,041
Total assets acquired	2,052,314
Liabilities assumed:	
Current liabilities	(24,844)
Asset retirement obligations	(3,705)
Deferred tax liabilities, net	(379,895)
Total liabilities assumed	(408,444)
Total identifiable net assets acquired	$ 1,643,870

The estimated fair value of assets acquired and liabilities assumed in the acquisition presented above are preliminary and subject to post-closing adjustments as more detailed analysis associated with the acquired properties are completed. As of the date of this report, we expect that it may take into mid-2017 until all post-closing adjustments are finalized.

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, and a market-based weighted-average cost of capital rate. These inputs require significant judgments and estimates by management at the time of the valuation and are the most sensitive and subject to change.

This acquisition was accounted for under the acquisition method. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred.

Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Among the factors that contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired were the acquisition of an element of a workforce and the expected value from operations of the Delaware Basin acquisition to be derived in the future. Goodwill related to the Delaware Basin acquisition was recorded in our oil and gas exploration and production segment. Any value assigned to goodwill is not expected to be deductible for income tax purposes.

Pro Forma Information. The results of operations for the Delaware Basin acquisition have been included in our consolidated financial statements since the December 6, 2016 closing date, including approximately $5.6 million of total revenue and $1.7 million of loss from operations. The following unaudited pro forma financial information represents a summary of the consolidated results of operations for the years ended December 31, 2016 and December 31, 2015, assuming the acquisition had been completed as of January 1, 2015. This pro forma financial information includes the Securities Issuances in September 2016, the shares issued to the sellers, and other acquisition costs. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective as of these dates, or of future results.

	Years Ended December 31,	
	2016	2015
	(in thousands, except per share amounts)	
Total revenue	$ 412,746	$ 598,932
Net loss	$ (270,942)	$ (138,904)
Earnings (loss) per share:		
Basic and diluted	$ (4.22)	$ (2.41)

NOTE 4 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated DD&A:

	As of December 31,	
	2016	2015
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 3,499,718	$ 2,881,189
Unproved	1,874,671	60,498
Total crude oil and natural gas properties	5,374,389	2,941,687
Infrastructure, pipeline, and other	62,093	30,098
Land and buildings	12,165	12,667
Construction in progress	122,591	113,115
Properties and equipment, at cost	5,571,238	3,097,567
Accumulated DD&A	(1,562,972)	(1,157,015)
Properties and equipment, net	$ 4,008,266	$ 1,940,552

Delaware Basin Acreage Acquisition. On December 30, 2016, we closed the purchase of approximately an additional 4,600 net bolt-on acres in Reeves and Culberson Counties, Texas, for consideration to the sellers of approximately $120.6 million, in cash, subject to post-closing adjustments. The transaction was accounted for as an acquisition of assets.

Acreage Exchange. In September 2016, we closed on an acreage exchange transaction with Noble Energy, Inc. and certain of its subsidiaries ("Noble") to consolidate certain acreage positions in the core area of the Wattenberg Field. Pursuant to the transaction, we exchanged leasehold acreage and, to a lesser extent, interests in certain development wells. Upon closing, we received approximately 13,500 net acres in exchange for approximately 11,700 net acres, with no cash exchanged between the parties. The assets exchanged were all in the same unit of production for property considerations, so it was concluded that this transaction was outside of the scope of the accounting requirements for recording the transaction at fair value and determining gain or loss on the non-monetary exchanges. The new acreage and underlying property costs were recorded at the previous historical cost of the assets we exchanged.

The following table presents impairment charges recorded for properties and equipment:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Impairment of proved and unproved properties	$ 5,562	$ 154,608	$ 161,604
Amortization of individually insignificant unproved properties	1,379	7,012	4,465
Land and buildings	3,032		778

Impairment of properties and equipment	9,973	161,620	166,847
Discontinued operations:			
Impairment of proved and unproved properties	—	—	433
Total discontinued operations	—	—	433
Total impairment of properties and equipment	$ 9,973	$ 161,620	$ 167,280

Due to a significant decline in commodity prices and decreases in our net realized sales prices, we experienced triggering events during 2015 and 2014 that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessments, we recorded impairment charges of $150.3 million and $158.3 million in 2015 and 2014, respectively, to write-down our Utica Shale proved and unproved properties. Of these impairment charges, $24.7 million and $112.6 million were recorded in 2015 and 2014, respectively, to write-down certain capitalized well costs on our Utica Shale proved producing properties. In 2015 and 2014, we also recorded impairment charges of $125.6 million and $45.7 million to write-down our Utica Shale lease acquisition costs. The impairment charges, which are included in the consolidated statements of operations line item impairment of properties and equipment, represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair values. We continued to monitor whether any further impairments were triggered and required measurement throughout 2016 given the continued volatility of commodity prices and the continued capital investment in the development and acquisition of oil and gas properties. No such triggering events occurred during 2016. Impairment charges in 2016 relate to the write-off of certain leases that were no longer part of our development plan and to reflect the fair value of other land and buildings that is held for sale as of December 31, 2016.

Suspended Well Costs

As of December 31, 2016 and 2015, there were no suspended well costs or wells pending determination.

NOTE 5 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas, and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas, we utilize the following economic hedging strategies for each of our business segments.

- For crude oil and natural gas sales, we enter into derivative contracts to protect against price declines in future periods. While we structure these commodity derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price increases in the physical market; and
- For gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical commodity derivatives in our gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

We believe our commodity derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of December 31, 2016, we had derivative instruments, which were comprised of collars, fixed-price commodity swaps, basis protection swaps, and physical sales and purchases, in place for a portion of our anticipated production through 2018 for a total of 81,720 BBtu of natural gas and 13,342 MBbls of crude oil. The commodity derivative contracts were entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices.

As of December 31, 2016, our derivative instruments were comprised of collars, fixed-price commodity swaps, basis protection swaps, and physical sales and purchases.

- Collars contain a fixed floor price (put) and ceiling price (call). If the index price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and index price from the counterparty. If the index price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty;
- Fixed-price commodity swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty. If the index price and contract price are the same, no payment is due to or from the counterparty;
- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG-basis protection swaps, which had a negative differential to NYMEX for the majority of 2016, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract. If the market price and contract price are the same, no payment is due to or from the counterparty; and
- Physical sales and purchases are commodity derivatives for fixed-priced physical transactions where we sell or purchase third-party supply at fixed rates. These physical commodity derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

We have elected not to designate any of our derivative instruments as cash flow hedges, and therefore do not qualify for use of hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations. Changes in the fair value of derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our Gas Marketing segment are recorded in sales from and cost of gas marketing.

The following table presents the balance sheet location and fair value amounts of our derivative instruments on the consolidated balance sheets as of December 31, 2016 and 2015:

Derivative instruments:		Consolidated Balance sheet line item	2016	2015
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	$ 8,239	$ 221,161
	Related to gas marketing	Fair value of derivatives	251	441
	Basis protection derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	301	57
			8,791	221,659
	Non-current			
	Commodity derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,104	44,292
	Related to gas marketing	Fair value of derivatives	19	51
	Basis protection derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,263	44
			2,386	44,387
Total derivative assets			$ 11,177	$ 266,046
Derivative liabilities:	Current			
	Commodity derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	$ 53,353	$ —
	Related to gas marketing	Fair value of derivatives	212	417
	Basis protection derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	30	1,178
			53,595	1,595
	Non-current			
	Commodity derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	27,581	275
	Related to gas marketing	Fair value of derivatives	14	46
	Basis protection derivative contracts -			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	374
			27,595	695
Total derivative liabilities			$ 81,190	$ 2,290

The following table presents the impact of our derivative instruments on our consolidated statements of operations:

	Year Ended December 31,		
Consolidated statements of operations line item	2016	2015	2014
	(in thousands)		
Commodity price risk management gain (loss), net -			
Net settlements	$ 208,103	$ 238,935	$ (837)
Net change in fair value of unsettled derivatives	(333,784)	(35,752)	311,141
Total commodity price risk management gain (loss), net	$ (125,681)	$ 203,183	$ 310,304
Sales from gas marketing -			
Net settlements	$ 543	$ 778	$ (208)
Net change in fair value of unsettled derivatives	(676)	(318)	364
Total sales from gas marketing	$ (133)	$ 460	$ 156
Cost of gas marketing -			
Net settlements	$ (483)	$ (745)	$ 346
Net change in fair value of unsettled derivatives	690	279	(451)
Total cost of gas marketing	$ 207	$ (466)	$ (105)

All of our financial derivative agreements contain master netting provisions that provide for the net settlement of all contracts through a single payment in the event of early termination. Our fixed-price physical purchase and sale agreements that qualify as derivative contracts are not subject to master netting provisions and are not significant. We have elected not to offset the fair value positions recorded on our consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

As of December 31, 2016	Derivative instruments, recorded in consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$ 11,177	$ (10,930)	$ 247
Liability derivatives:			
Derivative instruments, at fair value	$ 81,190	$ (10,930)	$ 70,260

As of December 31, 2015	Derivative instruments, recorded in consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$ 266,046	$ (1,921)	$ 264,125
Liability derivatives:			
Derivative instruments, at fair value	$ 2,290	$ (1,921)	$ 369

NOTE 6 - FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Financial Instruments

Determination of fair value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets

(Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Derivative Financial Instruments. We measure the fair value of our derivative instruments based on a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors, and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position.

We validate our fair value measurement through the review of counterparty statements and other supporting documentation, the determination that the source of the inputs is valid, the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. While we use common industry practices to develop our valuation techniques and believe our valuation method is appropriate and consistent with those used by other market participants, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Our fixed-price swaps, basis swaps, and physical purchases are included in Level 2 and our collars and physical sales are included in Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis:

	As of December 31,					
	2016			2015		
	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Total assets	$ 6,350	$ 4,827	$ 11,177	$ 174,758	$ 91,288	$ 266,046
Total liabilities	66,789	14,401	81,190	2,290	—	2,290
Net asset (liability)	$ (60,439)	$ (9,574)	$ (70,013)	$ 172,468	$ 91,288	$ 263,756

The following table presents a reconciliation of our Level 3 commodity derivative instruments measured at fair value:

	2016	2015	2014
	(in thousands)		
Fair value of Level 3 instruments, net asset beginning of period	$ 91,288	$ 62,356	$ 1,111
Changes in fair value included in consolidated statement of operations line item:			
Commodity price risk management gain (loss), net	(28,530)	65,018	62,003
Sales from gas marketing	(20)	146	(22)
Settlements included in statement of operations line items:			
Commodity price risk management gain (loss), net	(72,242)	(36,169)	(737)
Sales from gas marketing	(70)	(63)	1
Fair value of Level 3 instruments, net asset (liability) end of period	$ (9,574)	$ 91,288	$ 62,356
Net change in fair value of Level 3 unsettled derivatives included in statement of operations line item:			
Commodity price risk management gain (loss), net	$ (12,905)	$ 43,540	$ 15,632
Sales from gas marketing	—	—	3

Total	$ (12,905)	$ 43,540	$ 15,635

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, which is provided by a third-party vendor. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts. There has been no change in the methodology we apply to measure the fair value of our Level 3 derivative contracts during the periods covered by the financial statements.

Non-Derivative Financial Assets and Liabilities

The carrying value of the financial instruments included in current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

We utilize fair value on a nonrecurring basis to review our crude oil and natural gas properties for possible impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The fair value of the properties is determined based upon estimated future discounted cash flow, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil, natural gas and NGLs will be sold.

The portion of our long-term debt related to our revolving credit facility approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes or convertible notes under the fair value option; however, we have determined an estimate of the fair values based on measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs. The table below presents these estimates of the fair value of the portion of our long-term debt related to our senior notes and convertible notes as of December 31, 2016:

	Estimated Fair Value	% of Par
	(in millions)	
Senior notes:		
2021 Convertible Notes	$ 220.2	110.1%
2024 Senior Notes	408.0	102.0%
2022 Senior Notes	535.0	107.0%

The carrying value of our capital lease obligations approximates fair value due to the variable nature of the imputed interest rates and the duration of the vehicle lease.

NOTE 7 - CONCENTRATION OF RISK

Accounts Receivable. The following table presents the components of accounts receivable, net of allowance for doubtful accounts:

	As of December 31,	
	2016	2015
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 97,520	$ 41,873
Joint interest billings	20,118	35,017
Derivative counterparties	10,266	24,437
Income tax receivable	11,505	—
Insurance reimbursement	—	879
Other	6,173	4,077
Allowance for doubtful accounts	(2,190)	(2,009)
Accounts receivable, net	$ 143,392	$ 104,274

Our accounts receivable primarily relate to sales of our crude oil, natural gas, and NGLs production, receivable balances from other third parties that own working interests in the properties we operate, and derivative counterparties. For the years ended December 31, 2016 and 2015, amounts written off to allowance for doubtful accounts were not material. As of December 31, 2016, we had no customers representing 10 percent or greater of our accounts receivable balance. As of December 31, 2015, we had one customer representing 10 percent or greater of our accounts receivable balance.

Major Customers. The following table presents the individual customers constituting 10 percent or more of total revenues:

	Year Ended December 31,		
Customer	2016	2015	2014
Suncor Energy Marketing, Inc.	22.3%	14.3%	19.7%
DCP Midstream, LP	20.2%	13.2%	15.1%
Aka Energy Group, LLC	13.4%	—%	—%
Concord Energy, LLC	13.4%	23.2%	18.3%
Bridger Energy, LLC	11.5%	—%	—%
Shell Trading Company	—%	13.8%	—%
Teppco Crude Oil, LLC	—%	—%	12.9%

The concentration of revenue represented by the customers noted above relate to our oil and gas exploration and production segment.

Derivative Counterparties. A portion of our liquidity relates to commodity derivative instruments that enable us to manage a portion of our exposure to price volatility from producing crude oil and natural gas. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions who are also major lenders under our revolving credit facility as counterparties to our commodity derivative contracts; however, an insignificant portion of our commodity derivative instruments may be with other counterparties. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at December 31, 2016, taking into account the estimated likelihood of nonperformance.

Note Receivable

The following table presents information regarding our note receivable outstanding:

	As of December 31,	
	2016	2015
	(in thousands)	
Principal and PIK Interest outstanding at beginning of period	$ 43,069	$ 39,707
PIK Interest	969	3,362
Principal and PIK Interest outstanding at end of period	44,038	43,069
Allowance for uncollectible notes receivable	(44,038)	—
Note receivable, net	$ —	$ 43,069

In October 2014, we sold our entire 50 percent ownership interest in PDCM to an unrelated third-party as described in the footnote titled *Divestiture and Discontinued Operations*. As part of the consideration, we received a promissory note (the “Note”) for a principal sum of $39.0 million, bearing varying interest rates beginning at eight percent and increasing annually. Pursuant to the Note agreement, interest shall be paid quarterly, in arrears, commencing December 2014 and continuing on the last business day of each fiscal quarter thereafter. At the option of the issuer of the Note, an unrelated third-party, interest can be paid-in-kind (the “PIK Interest”) and any such PIK Interest will be added to the outstanding principal amount of the Note. Through December 31, 2016, the issuer of the Note had elected the PIK Interest option for each quarterly period since inception. The principal and any unpaid interest shall be due and payable in full in September 2020 and can be prepaid in whole or in part at any time, and in certain circumstances must be repaid prior to maturity. Any such prepayment will be made without premium or penalty. Legally, the Note is secured by a pledge of stock in certain subsidiaries of the unrelated third-party, debt securities and other assets; however, we believe that the collection of the Note is not reasonably assured.

We examine the Note for evidence of collectability, evaluating factors such as the creditworthiness of the issuer of the Note and the value of the underlying assets that secure the Note. We performed our evaluation and cash flow analysis during the first quarter of 2016 and, based upon the year-end financial statements for 2015, the crude oil and natural gas reserve report of the issuer of the Note, and existing market conditions, determined that collection of the Note and PIK Interest was not reasonably assured. As a result, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.0 million outstanding balance as of March 31, 2016, which was included in the consolidated balance sheet line item other assets. Commencing in the second quarter of 2016, we ceased recognizing interest income on the Note and began accounting for the interest on the Note under the cash basis method. To date, we have not received any interest payments. As of December 31, 2016, there has been no change to our assessment of the collectibility of the Note or related interest,

and continue to believe collection is not reasonably assured. Under the effective interest method, we previously recognized $4.5 million of interest income for the year ended December 31, 2015, of which $3.4 million was PIK Interest. As of December 2015, the $43.1 million outstanding balance on the Note was included in the consolidated balance sheet line item other assets.

Other Accrued Expenses. The following table presents the components of other accrued expenses:

	As of December 31,	
	2016	2015
	(in thousands)	
Employee benefits	$ 22,282	$ 17,774
Asset retirement obligations	9,775	5,460
Environmental expenses	3,238	4,143
Other	3,330	1,332
Other accrued expenses	$ 38,625	$ 28,709

NOTE 8 - INCOME TAXES

The table below presents the components of our provision for income taxes from continuing operations for the years presented:

	Year Ended December 31,		
	2016	2015	2014
		(in thousands)	
Current:			
Federal	$ 9,646	$ (2,944)	$ (1,514)
State	300	(163)	966
Total current income tax benefit (expense)	9,946	(3,107)	(548)
Deferred:			
Federal	118,427	37,352	(60,698)
State	18,822	4,063	(8,721)
Total deferred income tax benefit (expense)	137,249	41,415	(69,419)
Income tax benefit (expense) from continuing operations	$ 147,195	$ 38,308	$ (69,967)

The following table presents a reconciliation of the statutory rate to the effective tax rate related to our provision for income taxes from continuing operations:

	Year Ended December, 31,		
	2016	2015	2014
Statutory tax rate	35.0 %	35.0 %	35.0 %
State income tax, net	2.6	2.7	2.8
Effect of state income tax rate changes	0.6	(0.3)	—
Percentage depletion	—	0.3	(0.3)
Non-deductible compensation	(0.5)	(1.2)	0.7
Excess tax benefits from stock-based compensation	0.4	—	—
Other	(0.7)	(0.6)	1.3
Effective tax rate	37.4 %	35.9 %	39.5 %

Amendments related to accounting for excess tax benefits of stock-based compensation have been adopted prospectively, resulting in recognition of excess tax benefits against income tax expenses rather than APIC of $1.5 million for the year ended December 31, 2016. Excess tax benefits in the amount of $1.4 million were recognized as APIC during the year ended December 31, 2015, resulting from the vesting of stock-based compensation.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2016 and 2015 are presented below. Of note, the table includes the $403.7 million effect of including the deferred tax liability for the difference in the book and tax basis of the oil and gas properties acquired in the December 6, 2016, business combination and a $23.8 million of acquired deferred tax assets:

	As of December 31,	
	2016	2015
	(in thousands)	
Deferred tax assets:		
Deferred compensation	$ 9,338	$ 13,104
Asset retirement obligations	34,359	34,101
Federal NOL carryforward	29,988	—
State NOL and tax credit carryforwards, net	5,189	3,376
Alternative minimum tax - credit carryforward	5,184	2,812
Allowance for note receivable	17,292	—
Net change in fair value of unsettled derivatives	26,262	—
Other	4,716	3,412
Total gross deferred tax assets	132,328	56,805
Deferred tax liabilities:		
Properties and equipment	518,964	99,191
Net change in fair value of unsettled derivatives	—	100,369
Convertible debt	14,231	697
Total gross deferred tax liabilities	533,195	200,257
Net deferred tax liability	$ 400,867	$ 143,452

Deferred tax assets increased in 2016, primarily due to the allowance for a note receivable, acquired federal NOL from the stock acquisition component of the Delaware Basin acquisition, current year generated NOL and the reduced fair value of unsettled derivatives.

Deferred tax liabilities increased in 2016, primarily due to the deferred tax liability arising from the excess book basis versus tax carryover basis of the properties and equipment relating to the stock acquisition component of the Delaware Basin acquisition. Deferred tax liabilities also increased due to the 2021 Convertible Notes and accelerated deductions on properties and equipment. These were partially offset by the settlement of commodity derivatives and the decrease in fair value of unsettled commodity derivatives.

During the year ending December 31, 2016, we generated a federal NOL of $55.4 million of which $32.2 million will be utilized as a carryback leaving a federal NOL carryforward of $23.1 million that will begin to expire in 2036, and we have alternative minimum tax credits of $5.2 million that may be carried forward indefinitely. Also, we acquired a federal NOL of $62.5 million as a component of the Delaware Basin acquisition that will begin to expire in 2034 which is subject to an annual limitation of $15.1 million as a result of the acquisition, which constitutes a change of ownership as defined under IRS Code Section 382.

As of December 31, 2016, we have state NOL carryforwards of $130.5 million that begin to expire in 2030 and state credit carryforwards of $1.8 million that begin to expire in 2022.

Unrecognized tax benefits and related accrued interest and penalties were immaterial for the three-year period ended December 31, 2016. The total amount of unrecognized tax benefits that would affect the effective tax rate decreased to zero in the current year due to a settlement with the IRS on a tax filing position related to our 2014 federal tax return. The statutes of limitations for most of our state tax jurisdictions are open from 2012 forward.

The IRS fully accepted our recently filed 2015 return, with minor agreed-upon adjustments, after the IRS CAP post-filing review process was completed in early January 2017. We are currently participating in the CAP Program for the review of our 2016 and 2017 tax years. Participation in the CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

There has been increased discussion by the federal government of a potential reduction of the corporate income tax rate and corresponding changes to the tax code. In the event of a change in federal or state income tax rates, the impact of the rate change will be required to be recorded through deferred income tax expense. Should statutory income tax rates decrease, our deferred tax liability will decrease, resulting in deferred tax benefit for the period. If the statutory income tax rates increase, our deferred tax liability would increase resulting in a deferred tax expense.

As of December 31, 2016, we were current with our income tax filings in all applicable state jurisdictions.

NOTE 9 - LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31,	
	2016	2015
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due 2021:		
Principal amount	$ 200,000	$ —
Unamortized discount	(37,475)	—
Unamortized debt issuance costs	(4,584)	—
1.125% Convertible Notes due 2021, net of unamortized discount and debt issuance costs	157,941	—
6.125% Senior Notes due 2024:		
Principal amount	400,000	—
Unamortized debt issuance costs	(7,544)	—
6.125% Senior Notes due 2024, net of unamortized debt issuance costs	392,456	—
7.75% Senior notes due 2022:		
Principal amount	500,000	500,000
Unamortized debt issuance costs	(6,443)	(7,563)
7.75% Senior notes due 2022, net of unamortized debt issuance costs	493,557	492,437
3.25% Convertible senior notes due 2016:		
Principal amount	—	115,000
Unamortized discount	—	(1,852)
Unamortized debt issuance costs	—	(208)
3.25% Convertible senior notes due 2016, net of unamortized discount and debt issuance costs	—	112,940
Total senior notes	1,043,954	605,377
Revolving credit facility	—	37,000
Total debt, net of unamortized discount and debt issuance costs	1,043,954	642,377
Less current portion of long-term debt	—	112,940
Long-term debt	$ 1,043,954	$ 529,437

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200.0 million of 1.125% convertible senior notes due 2021 in a public offering. The 2021 Convertible Notes are governed by an indenture dated September 14, 2016 between us and the U.S. Bank National Association, as trustee. The maturity for the payment of principal is September 15, 2021. Interest at the rate of 1.125% per year is payable in cash semiannually in arrears on each March 15 and September 15, commencing on March 15, 2017. The 2021 Convertible Notes are senior unsecured obligations and rank senior in right of payment to our future indebtedness that is expressly subordinated to the 2021 Convertible Notes; equal in right of payment to our existing and future indebtedness that is not so subordinated; effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries. The proceeds from the issuance of the 2021 Convertible Notes, after deducting offering expenses and underwriting discounts, were used to fund a portion of the purchase price of acquisitions in the Delaware Basin, to pay related fees and expenses, and for general corporate purposes.

The 2021 Convertible Notes are convertible prior to March 15, 2021 only upon specified events and during specified periods and, thereafter, at any time, in each case at an initial conversion rate of 11.7113 shares of our common stock per $1,000 principal amount of the 2021 Convertible Notes, which is equal to an initial conversion price of approximately $85.39 per share. The conversion rate is subject to adjustment upon certain events. Upon conversion, the 2021 Convertible Notes may be settled, at our sole election, in shares of our common stock, cash, or a combination of cash and shares of our common stock. We have initially elected a combination settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the 2021 Convertible Notes in cash and to settle the excess conversion value, if any, in shares, as well as cash in lieu of fractional shares.

We may not redeem the 2021 Convertible Notes prior to their maturity date. If we undergo a "fundamental change", as defined in the indenture for the 2021 Convertible Notes, subject to certain conditions, holders of the 2021 Convertible Notes may require us to repurchase all or part of the 2021 Convertible Notes for cash at a price equal to 100 percent of the principal amount of the 2021 Convertible Notes to be repurchased, plus any accrued and unpaid interest to, but excluding, the fundamental change repurchase date. The occurrence of a fundamental change will also result in the 2021 Convertible Notes becoming convertible.

We allocated the gross proceeds of the 2021 Convertible Notes between the liability and equity components of the debt. The initial $160.5 million liability component was determined based on the fair value of similar debt instruments excluding the conversion feature for similar terms and priced on the same day we issued the 2021 Convertible Notes. The initial $39.5 million equity component represents the debt discount and was calculated as the difference between the fair value of the debt and the gross proceeds of the 2021 Convertible Notes. Approximately $4.8 million in costs associated with the issuance of the 2021 Convertible Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method. As of December 31, 2016, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the 2021 Convertible Notes using an effective interest rate of 5.8%. Based upon the December 31, 2016 stock price of $72.58 per share, the “if-converted” value of the 2021 Convertible Notes did not exceed the principal amount.

2024 Senior Notes. In September 2016, we issued $400.0 million aggregate principal amount of 6.125% senior notes due September 2024 in a private placement to qualified institutional buyers. In connection with the issuance of the 2024 Senior Notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC relating to an offer to exchange the 2024 Senior Notes for registered notes with substantially identical terms. In addition, we have agreed, in certain circumstances, to file a shelf registration statement covering the resale of the 2024 Senior Notes by the holders. The proceeds from the issuance of the 2024 Senior Notes, after deducting offering expenses and underwriting discounts, were used to fund a portion of the purchase price of acquisitions in the Delaware Basin (see the footnotes titled *Business Combination* and *Properties and Equipment)*, to pay related fees and expenses, and for general corporate purposes.

The 2024 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually in arrears on March 15 and September 15, commencing on March 15, 2017. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method. The 2024 Senior Notes are senior unsecured obligations and rank senior in right of payment to our future indebtedness that is expressly subordinated to the notes; equal in right of payment to all our existing and future indebtedness that is not so subordinated; effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowings under our revolving credit facility; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries.

The 2024 Senior Notes are redeemable after September 15, 2019, at fixed redemption prices beginning at 104.594 percent of the principal amount redeemed. At any time prior to September 15, 2019, we may redeem all or part of the 2024 Senior Notes at a make-whole price set forth in the indenture which generally approximates the present value of the redemption price at September 15, 2019, and remaining interest payments on the 2024 Senior Notes at the time of redemption.

At any time prior to September 15, 2019, we may redeem up to 35 percent of the outstanding 2024 Senior Notes with proceeds from certain equity offerings at a redemption price of 106.125 percent of the principal amount of the notes redeemed, plus accrued and unpaid interest, if at least 65 percent of the aggregate principal amount of the 2024 Senior Notes remains outstanding after each such redemption and the redemption occurs within 180 days after the closing of the equity offering.

Upon the occurrence of a "change of control," as defined in the indenture for the 2024 Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we may, under certain circumstances, be required to use the net cash proceeds of such asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with any accrued and unpaid interest to the date of purchase.

The indenture governing the 2024 Senior Notes contains covenants that, among other things, limit our ability and the ability of our subsidiaries to incur additional indebtedness; pay dividends or make distributions on our stock; purchase or redeem stock or subordinated indebtedness; make investments; create certain liens; enter into agreements that restrict distributions or other payments by restricted subsidiaries to us; enter into transactions with affiliates; sell assets; consolidate or merge with or into other companies or transfer all or substantially of our assets; and create unrestricted subsidiaries.

2022 Senior Notes. In October 2012, we issued $500.0 million aggregate principal amount 7.75% senior notes due October 15, 2022 in a private placement to qualified institutional buyers. The 2022 Senior Notes have been registered. The 2022 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually in arrears on April 15 and October 15. Approximately $11.0 million in costs associated with the issuance of the 2022 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method. The 2022 Senior Notes are senior unsecured obligations and rank senior in right of payment to any of our future indebtedness that is expressly subordinated to the notes. The 2022 Senior Notes rank equally in right of payment with all our existing and future senior indebtedness and rank effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the collateral securing such indebtedness and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries.

At any time prior to October 15, 2017, we may redeem all or part of the 2022 Senior Notes at a make-whole price set forth in the indenture. On or after October 15, 2017, we may redeem the notes at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption.

Upon the occurrence of a "change of control" as defined in the indenture for the 2022 Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we will be required to use the net cash proceeds of the asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with any accrued and unpaid interest to the date of purchase.

The indenture governing the 2022 Senior Notes contains covenants that, among other things, limit our ability and the ability of our subsidiaries to incur additional indebtedness; pay dividends or make distributions on our stock; purchase or redeem stock or subordinated indebtedness; make certain investments; create certain liens; restrict dividends or other payments by restricted subsidiaries; enter into transactions with affiliates; sell assets; and merge or consolidate with another company.

In January 2017, pursuant to the filing of the supplemental indentures for the 2021 Convertible Notes, 2024 Senior Notes, and the 2022 Senior Notes our subsidiary, PDC Permian, Inc., became a guarantor of our obligations under the notes.

As of December 31, 2016, we were in compliance with all covenants related to the 2021 Convertible Notes, 2024 Convertible Notes and the 2022 Senior Notes, and expect to remain in compliance throughout the foreseeable future.

2016 Convertible Senior Notes. In November 2010, we issued $115.0 million aggregate principal amount of 3.25% convertible senior notes due that were due in 2016 ("2016 Convertible Notes") in a private placement. The maturity for the payment of principal was May 15, 2016, and we paid the aggregate principal amount of the 2016 Convertible Notes, plus cash for the fractional shares, totaling approximately $115.0 million. Additionally, we issued 792,406 shares of common stock for the $47.9 million excess conversion value. See the footnote titled *Common Stock* for more information.

Revolving Credit Facility

Revolving Credit Facility. Our revolving credit facility matures in May 2020. The revolving credit facility is available for working capital requirements, capital investments, acquisitions, general corporate purposes and to support letters of credit. The revolving credit facility provides for a maximum of $1 billion in allowable borrowing capacity, subject to the borrowing base determination and subject to limitations under the 2022 Senior Notes. The amount available under the revolving credit facility is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests, excluding proved reserves attributable to our affiliated partnerships. The borrowing base is subject to a semi-annual size redetermination on November 1 and May 1 based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. The revolving credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing crude oil and natural gas properties and substantially all of our and such subsidiaries' other assets. Our affiliated partnerships are not guarantors of our obligations under the revolving credit facility. The current borrowing base and aggregate commitments under the facility are $700 million.

The weighted-average borrowing rate on our revolving credit facility, exclusive of fees on the unused commitment and the letter of credit noted below, was 2.7 percent and 2.6 percent per annum for the years ended December 31, 2016 and 2015, respectively. We capitalized $8.8 million and $3.6 million of debt issuance costs as of December 31, 2016 and 2015, respectively, related to our revolving credit facility which is included in other assets on the consolidated balance sheets.

We had no outstanding balance on our revolving credit facility as of December 31, 2016 compared to $37.0 million outstanding as of December 31, 2015. The outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greater of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus an applicable margin and the rate for dollar deposits in the London interbank market (“LIBOR”) for one month plus a premium), or at our election, a rate equal to LIBOR for certain time periods. Additionally, commitment fees, interest margin, and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of December 31, 2016, the applicable margin is 1.25 percent, and the unused commitment fee is 0.50 percent. No principal payments are generally required until the credit agreement expires in May 2020, or in the event that the borrowing base falls below the outstanding balance.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.00:1.00 and (b) not exceed a maximum leverage ratio of 4.00:1.00. Our borrowing base availability under the revolving credit facility is limited under our 2022 Senior Notes to the greater of $700 million or the calculated value under an Adjusted Consolidated Tangible Net Asset test, as defined in the applicable indenture. As of December 31, 2016, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the foreseeable future. As of December 31, 2016, our calculated debt to EBITDAX ratio was 2.10 and our current ratio was 5.00.

The revolving credit facility contains restrictions as to when we can directly or indirectly retire, redeem, repurchase, or prepay in cash any part of the principal of the 2021 Convertible Notes, 2022 Senior Notes, or 2024 Senior Notes. Among other things, the restriction on redemption of the 2021 Convertible Notes requires that immediately after giving effect to any such retirement, redemption, defeasance, repurchase, settlement, or prepayment, the aggregate commitment under the revolving credit facility must exceed the aggregate credit exposure under such facility by at least an amount equal to or greater than 20 percent of such aggregate commitment.

As of December 31, 2016, RNG had issued an irrevocable standby letter of credit of approximately $11.7 million in favor of a third-party transportation service provider to secure firm transportation of the natural gas produced by third-party producers for whom we market production in the Appalachian Basin. The letter of credit currently expires in September 2017 and is automatically extended annually in accordance with the letter of credit's terms and conditions. The letter of credit reduces the amount of available funds under our revolving credit facility by an amount equal to the letter of credit. As of December 31, 2016, the available funds under our revolving credit facility, including the reduction for the $11.7 million letter of credit, was $688.3 million.

NOTE 10 - CAPITAL LEASES

We periodically enter into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. These leases are being accounted for as capital leases, as the present value of minimum monthly lease payments, including the residual value guarantee, exceeds 90 percent of the fair value of the leased vehicles at inception of the lease.

The following table presents leased vehicles under capital leases:

	As of December 31,	
	2016	2015
	(in thousands)	
Vehicles	$ 2,975	$ 1,601
Accumulated depreciation	(776)	(211)
	$ 2,199	$ 1,390

Future minimum lease payments by year and in the aggregate, under non-cancelable capital leases with terms of one year or more, consist of the following:

For the Twelve Months Ending December 31,	Amount
	(in thousands)
2017	$ 914
2018	1,099
2019	560
	2,573
Less executory cost	(96)
Less amount representing interest	(263)
Present value of minimum lease payments	$ 2,214
Short-term capital lease obligations	$ 699
Long-term capital lease obligations	1,515
	$ 2,214

Short-term capital lease obligations are included in other accrued expenses on the consolidated balance sheets. Long-term capital lease obligations are included in other liabilities on the consolidated balance sheets.

NOTE 11 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interest in crude oil and natural gas properties:

	2016	2015
	(in thousands)	
Balance at beginning of period	$ 89,492	$ 73,855
Obligations incurred with development activities and assumed with acquisitions	4,894	2,373
Accretion expense	7,080	6,293
Revisions in estimated cash flows	—	11,658
Obligations discharged with disposal of properties and asset retirements	(9,079)	(4,687)
Balance at end of period	92,387	89,492
Less current portion	(9,775)	(5,460)
Long-term portion	$ 82,612	$ 84,032

Our estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. In 2016, the credit-adjusted risk-free rates used to discount our plugging and abandonment liabilities ranged from 6.5 percent to 8.2 percent. In periods subsequent to initial measurement of the liability, we must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or changes in inflation factors, and changes to our credit-adjusted risk-free rate as market conditions warrant.

The increase in the current portion of asset retirement obligations in 2016 is attributable to an increase in the number of wells to be plugged and abandoned to allow for the drilling of nearby horizontal wells. The revisions in estimated cash flows during 2015 were due to changes in estimates of costs for materials and services related to the plugging and abandonment of certain vertical wells in the Wattenberg Field, as well as a decrease in the estimated useful life of these wells.

NOTE 12 - EMPLOYEE BENEFIT PLANS

We sponsor a qualified retirement plan covering substantially all of our employees. The plan consists of both a traditional and a Roth 401(k) component, as well as a profit sharing component. The 401(k) components enable eligible employees to contribute a portion of their compensation through payroll deductions in accordance with specific guidelines. We provide a discretionary matching contribution based on a percentage of the employees' contributions up to certain limits. Our contribution to the profit sharing component is discretionary. Our total combined expense for the plan was $4.8 million, $4.9 million, and $3.9 million for 2016, 2015, and 2014, respectively.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Firm Transportation, Processing and Sales Agreements. We enter into contracts that provide firm transportation, sales, and processing agreements on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us, purchased from third parties and produced by our affiliated partnerships and other third-party working, royalty and overriding royalty interest owners whose volumes we market on their behalf. Our statements of operations reflect our share of these firm transportation costs. These contracts require us to pay these transportation and processing charges, whether or not the required volumes are delivered. As natural gas prices remain depressed, certain third-party producers under our Gas Marketing Segment have continued to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, no counterparty default losses have been material to us. In 2016 and 2015, we recorded an allowance for doubtful accounts of approximately $1.3 million and $0.5 million, respectively. We have initiated several legal actions for breach of contract, collection, and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in two default judgments.

The following table presents gross volume information related to our long-term firm transportation, sales and processing agreements for pipeline capacity:

Area	Year Ending December 31, 2017	2018	2019	2020	2021 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field (1)	—	2,300	17,125	18,300	86,700	124,425	September 30, 2025
Gas Marketing segment	7,117	7,117	7,117	7,136	11,550	40,037	August 31, 2022
Utica Shale	2,738	2,738	2,738	2,745	7,064	18,023	July 22, 2023
Total	9,855	12,155	26,980	28,181	105,314	182,485	
Crude oil (MBbls)							
Wattenberg Field	2,413	2,413	2,413	1,204	—	8,443	June 30, 2020
Dollar commitment (in thousands)	$ 17,158	$ 18,626	$ 33,221	$ 27,430	$ 89,896	$ 186,331	

(1) In December 2016, in anticipation of our future drilling activities in the Wattenberg Field, we entered into a facilities expansion agreement with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities. The midstream provider is expected to construct a new 200 MMcfd cryogenic plant. We will be bound to the volume requirements in this agreement on the first day of the calendar month after the actual in-service date of the plant, which in the above table is estimated to be September 30, 2018. The agreement requires a baseline volume commitment of current sales volumes to this midstream provider and an incremental volume commitment of 50 MMcfd for seven years, of which we may be required to pay a shortfall fee for any volumes under the 50 MMcfd incremental commitment. Any shortfall of this volume commitment may be offset, in part, by additional third party producers' volumes sold to the midstream provider when a certain total volume is achieved. We are also required for the first three years of the contract to guarantee a certain target profit margin to the midstream provider on these volumes sold. Under our current drilling plans, we expect to meet both the baseline and incremental volume commitments. Using the NYMEX forward pricing strip at December 31, 2016, the target profit margin would be achieved without an additional payment from us.

During 2016, 2015, and 2014, long-term firm transportation costs for our Gas Marketing segment as shown above were $3.4 million in each year and were recorded in cost of gas marketing in our consolidated statements of operations. For the years 2016, 2015, and 2014, commitments for long-term transportation volumes for Utica Shale natural gas and Wattenberg Field crude oil were $10.0 million, $4.7 million, and $0.3 million, respectively, and were recorded in transportation, gathering and processing expense in our consolidated statements of operations.

Litigation and Legal Items. The Company is involved in various legal proceedings. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. Management has provided the necessary estimated accruals in the accompanying balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations, or liquidity.

Class Action Regarding 2010 and 2011 Partnership Purchases

We finalized a settlement associated with the repurchase of certain partnership purchases in 2015. All required amounts associated with this settlement had been expensed in 2014.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. We are not aware of any environmental claims existing as of December 31, 2016, which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown past non-compliance with environmental laws will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses on the consolidated balance sheets.

In August 2015, we received the Information Request from the EPA. The Information Request sought, among other things, information related to the design, operation, and maintenance of our Wattenberg Field production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focuses on historical operation and design information for 46 of our production facilities and asks that we conduct sampling and analyses at the identified 46 facilities. We responded to the the Information Request in January 2016. Throughout 2016, we continued to meet with the EPA, Department of Justice, and Colorado Department of Public Health and Environment, and in December we received a draft consent decree from the EPA.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. 25-7-115(2) from the Colorado Department of Public Health and Environment's Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate, and maintain certain condensate collection, storage, processing, and handling operations to minimize leakage of volatile organic compounds at 65 facilities consistent with applicable standards under Colorado law. We are in the process of responding to the advisory, but cannot predict the outcome of this matter at this time.

Lease Agreements. We entered into operating leases, principally for the leasing of natural gas compressors, office space, and general office equipment.

The following table presents the minimum future lease payments under the non-cancelable operating leases as of December 31, 2016:

	Year Ending December 31,						
	2017	2018	2019	2020	2021	Thereafter	Total
				(in thousands)			
Minimum Lease Payments	$ 3,056	$ 3,041	$ 3,033	$ 3,093	$ 3,154	$ 6,786	$ 22,163

Operating lease expense for 2016, 2015, and 2014 was $10.2 million, $9.8 million, and $7.0 million, respectively.

NOTE 14 - COMMON STOCK

Sale of Equity Securities

We issued 9.4 million shares of common stock as partial consideration for 100 percent of the common stock of Arris Petroleum and for the acquisition of certain Delaware Basin properties on December 6, 2016. These shares are restricted for sale until June 6, 2017, due to previously-disclosed lock up agreements. Accordingly, the value of the shares was discounted from the market price on the date of issuance by 6 percent.

The following table provides a summary of our public offerings of common stock in 2016 and 2015:

Date	Shares Issued	Price per Share	Net Proceeds
			(in millions)
September 2016	9,085,000	$ 61.51	$ 558.5
March 2016	5,922,500	50.11	296.6
March 2015	4,002,000	50.73	202.9

Stock-Based Compensation Plans

2010 Long-Term Equity Compensation Plan. In June 2010, our stockholders approved a long-term equity compensation plan for our employees and non-employee directors (the "2010 Plan"). The plan was amended in June 2013. In accordance with the 2010 Plan, up to 3,000,000 new shares of our common stock are authorized for issuance. Shares issued may be either authorized but unissued shares, treasury shares, or any combination of these shares. Additionally, the 2010 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited or, in the case of stock appreciation rights ("SARs"), paid out in the form of cash. Awards may be issued to our employees in the form of SARs, restricted stock, restricted stock units ("RSUs"), performance shares, and performance units, and to our non-employee directors in the form of non-qualified stock options, SARs, restricted stock, and RSUs. Awards may vest over periods set at the discretion of the Compensation Committee of our Board of Directors (the "Compensation Committee") with certain minimum vesting periods. With regard to SARs, awards have a maximum exercisable period of ten years. In no event may an award be granted under the 2010 Plan on or after April 1, 2020. As of December 31, 2016, 839,052 shares remain available for issuance pursuant to the 2010 Plan.

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Stock-based compensation expense	$ 19,502	$ 20,068	$ 17,518
Income tax benefit	(7,296)	(7,636)	(5,955)
Net stock-based compensation expense	$ 12,206	$ 12,432	$ 11,563

Stock Appreciation Rights ("SARs")

The SARs vest ratably over a three-year period and may be exercised at any point after vesting through ten years from the date of issuance. Pursuant to the terms of the awards, upon exercise, the executive officers will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

The Compensation Committee has awarded SARs to our executive officers in 2016, 2015, and 2014. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the following assumptions:

	Year Ended December 31,		
	2016	2015	2014
Expected term of award	6.0 years	5.2 years	6.0 years
Risk-free interest rate	1.8%	1.4%	2.1%
Expected volatility	54.5%	58.0%	65.6%
Weighted-average grant date fair value per share	$ 26.96	$ 22.23	$ 29.96

The expected term of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

The following table presents the changes in our SARs for all periods presented:

	Year Ended December 31,									
	2016				2015			2014		
	Number of SARs	Weighted-Average Exercise Price	Average Remaining Contractual Term *(in years)*	Aggregate Intrinsic Value *(in thousands)*	Number of SARs	Weighted-Average Exercise Price	Aggregate Intrinsic Value *(in thousands)*	Number of SARs	Weighted-Average Exercise Price	Aggregate Intrinsic Value *(in thousands)*
Outstanding beginning of year, January 1,	326,453	$ 38.99	7.3	$ 4,697	279,011	$ 38.77	$ 1,472	190,763	$ 33.77	$ 3,711
Awarded	58,709	51.63	—	—	68,274	39.63	—	88,248	49.57	—
Exercised	(141,084)	40.16	—	2,770	(20,832)	38.05	473	—	—	—
Outstanding at December 31,	244,078	41.36	6.9	7,620	326,453	38.99	4,697	279,011	38.77	1,472
Exercisable at December 31,	174,919	38.72	6.3	5,924	222,489	37.70	3,489	139,334	36.27	982

Total compensation cost related to SARs granted and not yet recognized in our consolidated statements of operations as of December 31, 2016, was $1.5 million. The cost is expected to be recognized over a weighted-average period of 1.7 years.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based restricted shares is amortized ratably over the requisite service period, primarily three years. The time-based shares generally vest ratably on each anniversary following the grant date that a participant is continuously employed.

The following table presents the changes in non-vested time-based awards during 2016:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested at December 31, 2015	525,081	$ 50.23
Granted	290,010	58.52
Vested	(317,034)	48.61
Forfeited	(18,415)	56.10
Non-vested at December 31, 2016	479,642	56.09

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2016	2015	2014
	(in thousands, except per share data)		
Total intrinsic value of time-based awards vested	$ 18,973	$ 17,077	$ 18,278
Total intrinsic value of time-based awards non-vested	34,812	28,029	23,290
Market price per common share as of December 31,	72.58	53.38	41.27
Weighted-average grant date fair value per share	58.52	48.88	56.45

Total compensation cost related to non-vested time-based awards and not yet recognized in our consolidated statements of operations as of December 31, 2016 was $17.5 million. This cost is expected to be recognized over a weighted-average period of 1.9 years.

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of three years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

In January 2016, the Compensation Committee awarded a total of 24,280 market-based restricted shares to our executive officers. In addition to continuous employment, the vesting of these shares is contingent on the Company's total stockholder return ("TSR"), which is essentially the Company's stock price change including any dividends, as compared to the TSR of a group of peer companies. The shares are measured over a three-year period ending on December 31, 2018 and can result in a payout between 0 percent and 200 percent of the total shares awarded. As of December 31, 2016, we had approximately 48,000 non-vested market based restricted shares that could result in a payout between 0 and approximately 96,000 shares of our common stock. The weighted-average grant date fair value per market-based share for these awards granted was computed using the Monte Carlo pricing model using the following assumptions:

	Year Ended December 31,	
	2016	2015
Expected term of award	3 years	3 years
Risk-free interest rate	1.2%	0.9%
Expected volatility	52.3%	53.0%
Weighted-average grant date fair value per share	$ 72.54	$ 66.16

The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our historical volatility.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the change in non-vested market-based awards during 2016:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2015	71,549	$ 63.60
Granted	24,280	72.54
Vested	(47,409)	66.78
Non-vested at December 31, 2016	48,420	64.97

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2016	2015	2014
	(in thousands, except per share data)		
Total intrinsic value of market-based awards vested	$ 6,562	$ 4,293	$ 1,260
Total intrinsic value of market-based awards non-vested	3,514	3,819	3,455
Market price per common share as of December 31,	72.58	53.38	41.27
Weighted-average grant date fair value per share	72.54	66.16	56.87

Total compensation cost related to non-vested market-based awards and not yet recognized in our consolidated statements of operations as of December 31, 2016 was $1.7 million. This cost is expected to be recognized over a weighted-average period of 1.7 years.

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees and directors may surrender shares of the Company's common stock to pay tax withholding obligations upon the vesting and exercise of share-based awards. Shares acquired that had been issued pursuant to the 2010 Plan are reissued for new grants. For shares reissued for new grants under the 2010 Plan, shares are recorded at cost and upon reissuance we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted-average cost per share with an offsetting charge to APIC. As of December 3, 2015, we had 9,009 shares remaining available for reissuance pursuant to our 2010 plan. Additionally, as of December 31, 2016 and 2015, we had 18,366 and 11,211, respectively, of shares of treasury stock related to a rabbi trust. During the year ended December 31, 2016, we acquired 116,085 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 114,697 shares were reissued and 10,397 shares are available for reissuance pursuant to our 2010 Plan.

Stockholders' Rights Agreement

In 2007, we entered into a rights agreement designed to improve the ability of our Board to protect the interest of our stockholders in the event of an unsolicited takeover attempt. The rights agreement and all rights were set to expire in September 2017. In June 2016, we entered into an amendment to the rights agreement, which accelerated the expiration date from September 2017 to June 2016. Upon the expiration in June 2016, all of the rights distributed to holders of our common stock pursuant to the rights agreement expired. The amendment was entered into as a result of governance considerations and not in contemplation of any anticipated business combination or similar transaction.

Preferred stock

We are authorized, pursuant to stockholder approval in 2008, to issue 50,000,000 shares of preferred stock, par value $0.01, which may be issued in one or more series, with such rights, preferences, privileges, and restrictions as shall be fixed by our Board from time to time. As of December 31, 2016, no preferred shares had been issued.

NOTE 15 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed except that the denominator includes the effect, using the treasury stock method, of unvested restricted stock, outstanding SARs, stock options, Convertible Notes, and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents a reconciliation of the weighted-average diluted shares outstanding:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Weighted-average common shares outstanding - basic	49,052	39,153	35,784
Dilutive effect of:			
Restricted stock	—	—	279
Convertible notes	—	—	564
Other equity-based awards	—	—	51
Weighted-average common shares and equivalents outstanding - diluted	49,052	39,153	36,678

For 2016 and 2015, we reported a net loss. As a result, our basic and diluted weighted-average common shares outstanding were the same because the effect of the common share equivalents was anti-dilutive.

The following table presents the weighted-average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
Restricted stock	689	831	8
Convertible notes	292	562	—
Other equity-based awards	109	101	26
Total anti-dilutive common share equivalents	1,090	1,494	34

In September 2016, we issued the 2021 Convertible Notes, which give the holders the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes would be included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeds the $85.39 conversion price during the periods presented.

In November 2010, we issued the 2016 Convertible Notes, which give the holders the right to convert the aggregate principal amount into 2.7 million shares of our common stock at a conversion price of $42.40 per share. The 2016 Convertible Notes matured and were redeemed in May 2016, as described more fully in the footnote titled *Long Term Debt.* Prior to maturity, the 2016 Convertible Notes were included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeded the $42.40 conversion price during the period presented. Shares issuable upon conversion of the Convertible Notes were excluded from the diluted earnings per share calculation for the year ended December 31, 2015 as the effect would have been anti-dilutive to our earnings per share. Shares issuable upon conversion of the 2016 Convertible Notes were included in the diluted earnings per share calculation for the year ended December 31, 2014 as the average market price during the period exceeded the conversion price.

NOTE 16 - DIVESTITURE AND DISCONTINUED OPERATIONS

In October 2014, we completed the sale of our entire 50 percent ownership interest in PDCM to an unrelated third-party for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $192 million, comprised of approximately $153 million in net cash proceeds and a promissory note due in 2020 of approximately $39 million. The transaction included the buyer's assumption of our share of the firm transportation commitment related to the assets owned by PDCM, as well as our share of PDCM's natural gas hedging positions for the years 2014 through 2017. The divestiture resulted in a pre-tax gain of $76.3 million. As the divestiture represented a strategic shift that had a major effect on our operations as our organization structure no longer has joint venture partners and we no longer have dry gas assets, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the consolidated statements of operations for the year ended December 31, 2014.

The tables below set forth selected financial information related to net assets divested and operating results related to discontinued operations. The following table presents consolidated statements of operations data related to our discontinued operations:

Consolidated statements of operations - discontinued operations	Year Ended December 31, 2014
	(in thousands)
Revenues	
Crude oil, natural gas and NGLs sales	$ 24,149
Commodity price risk management loss, net	(1,085)
Other income	48
Total revenues	23,112
Costs, expenses and other	
Lease operating expenses	1,280
Production taxes	1,579
Transportation, gathering and processing expenses	3,536
Impairment of properties and equipment	433
Depreciation, depletion and amortization	9,128
Other	4,170
Gain on sale of properties and equipment	(76,479)
Total costs, expenses and other	(56,353)
Interest expense	(2,222)
Interest income	194
Income from discontinued operations	77,437
Provision for income taxes	(29,263)
Income from discontinued operations, net of tax	$ 48,174

The following table presents supplemental cash flows information related to our 50 percent ownership interest in PDCM, which is classified as discontinued operations:

Supplemental cash flows information - discontinued operations	Year Ended December 31, 2014
	(in thousands)
Cash flows from investing activities:	
Capital expenditures	$ (17,253)
Significant non-cash investing items:	
Change in accounts payable related to purchases of properties and equipment	(5,727)

NOTE 17 - TRANSACTIONS WITH AFFILIATES

PDCM. In 2014, our Gas Marketing segment marketed the natural gas produced by PDCM. Our cost of gas marketing includes $23.2 million in 2014 related to the marketing of this gas.

NOTE 18 - BUSINESS SEGMENTS

We separate our operating activities into two segments: Oil and Gas Exploration and Production and Gas Marketing. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Exploration and Production. Our Oil and Gas Exploration and Production segment includes all of our crude oil and natural gas properties. The segment represents revenues and expenses from the production and sale of crude oil, natural gas, and NGLs. Segment revenue includes crude oil, natural gas, and NGLs sales, commodity price risk management, net, and other income. Segment income (loss) consists of segment revenue less production cost, exploration expense, impairment of properties and equipment, direct general and administrative expense, and DD&A expense. Segment DD&A expense was $413.1 million, $298.8 million, and $188.5 million in 2016, 2015, and 2014, respectively.

Gas Marketing. Our Gas Marketing segment purchases, aggregates, and resells natural gas. Segment income (loss) primarily represents sales from gas marketing and direct interest income less costs of gas marketing, transportation and direct general and administrative expense.

Unallocated amounts. Unallocated income includes unallocated other revenue, less corporate general administrative expense, corporate DD&A expense, interest income, and interest expense. Unallocated assets include assets utilized for corporate, general and administrative purposes, as well as assets not specifically included in our two business segments.

The following tables present our segment information:

	2016	2015	2014
		(in thousands)	
Year Ended December 31,			
Segment revenues:			
Oil and gas exploration and production	$ 374,190	$ 584,406	$ 784,636
Gas marketing	8,725	10,920	71,571
Total revenues	$ 382,915	$ 595,326	$ 856,207
Segment income (loss) before income taxes:			
Oil and gas exploration and production	$ (170,370)	$ 31,429	$ 344,149
Gas marketing	(1,468)	(797)	(445)
Unallocated	(221,285)	(137,220)	(166,476)
Income (loss) before income taxes	$ (393,123)	$ (106,588)	$ 177,228
Expenditures for segment long-lived assets:			
Oil and gas exploration and production	$ 436,884	$ 599,617	$ 623,912
Acquisition of crude oil and natural gas properties, net of cash acquired	1,073,723	—	—
Unallocated	3,464	5,051	4,680
Total	$ 1,514,071	$ 604,668	$ 628,592
As of December 31,			
Segment assets:			
Oil and gas exploration and production	$ 4,451,510	$ 2,294,288	
Gas marketing	4,329	4,217	
Unallocated	30,003	72,038	
Total assets	$ 4,485,842	$ 2,370,543	

SUPPLEMENTAL INFORMATION - UNAUDITED

CRUDE OIL AND NATURAL GAS INFORMATION - UNAUDITED

Net Proved Reserves

All of our crude oil, natural gas, and NGLs reserves are located in the U.S. We utilize the services of independent petroleum engineers to estimate our crude oil, natural gas, and NGL reserves. As of December 31, 2016, 2015, and 2014, all of our estimates of proved reserves for the Wattenberg Field and the Utica Shale were based on reserve reports prepared by Ryder Scott and beginning in 2016, NSAI prepared the reserve reports for the Delaware Basin. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves are those quantities of crude oil, natural gas, and NGLs which can be estimated with reasonable certainty to be economically producible under existing economic conditions and operating methods. Proved developed reserves are the proved reserves that can be produced through existing wells with existing equipment and infrastructure and operating methods. Proved undeveloped 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 development. All of our proved undeveloped reserves conform to the SEC five-year rule requirement to be drilled within five years of each location's initial booking date.

The indicated index prices for our reserves, by commodity, are presented below.

	Average Benchmark Prices		
As of December 31,	Crude Oil *(per Bbl)*	Natural Gas *(per Mcf)*	NGLs *(per Bbl)*
2016	$ 42.75	$ 2.48	$ 42.75
2015	50.28	2.59	50.28
2014	94.99	4.35	94.99

The netted back price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves*		
As of December 31,	Crude Oil *(per Bbl)*	Natural Gas *(per Mcf)*	NGLs *(per Bbl)*
2016	$ 38.67	$ 1.85	$ 11.97
2015	42.10	2.05	12.23
2014	84.65	3.92	32.27

*These prices are based on the index prices and are net of basin differentials, any transportation fees, contractual adjustments, and any Btu adjustments we experienced for the respective commodity.

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SUPPLEMENTAL INFORMATION
(Unaudited)

The following tables present the changes in our estimated quantities of proved reserves:

	Crude Oil, Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved Reserves:				
Proved reserves, January 1, 2014 (1)	93,830	739,640	48,671	265,774
Revisions of previous estimates	(29,777)	(149,064)	(10,204)	(64,825)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	40,792	202,957	23,411	98,029
Acquisition of reserves	5	43	5	17
Dispositions	(13)	(237,306)	(8)	(39,572)
Production	(4,322)	(19,298)	(1,756)	(9,294)
Proved reserves, December 31, 2014	100,515	536,972	60,119	250,129
Revisions of previous estimates	(43,268)	(154,775)	(24,407)	(93,471)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	48,707	311,709	30,835	131,494
Acquisition of reserves	17	215	23	76
Dispositions	(12)	(82)	(8)	(34)
Production	(6,984)	(33,302)	(2,835)	(15,369)
Proved reserves, December 31, 2015	98,975	660,737	63,727	272,825
Revisions of previous estimates	(22,097)	(80,426)	(7,130)	(42,631)
Extensions, discoveries and other additions	494	4,094	355	1,531
Acquisition of reserves	50,126	305,224	32,586	133,583
Dispositions	(601)	(4,202)	(424)	(1,725)
Production	(8,728)	(51,730)	(4,826)	(22,176)
Proved reserves, December 31, 2016	118,169	833,697	84,288	341,407

Proved Developed Reserves, as of:				
December 31, 2014	26,798	186,633	17,002	74,905
December 31, 2015	26,257	175,367	15,011	70,496
December 31, 2016	30,013	264,452	24,196	98,284
Proved Undeveloped Reserves, as of:				
December 31, 2014	73,717	350,339	43,117	175,224
December 31, 2015	72,718	485,370	48,716	202,329
December 31, 2016	88,156	569,245	60,092	243,122

2016 Activity. During 2016, we increased proved reserves by 25 percent or 68.6 MMBoe, relative to December 31, 2015. This proved reserve increase was primarily a result of the development of longer lateral length well bores in the Wattenberg Field, which was driven by technology advancements, together with the ability to consolidate our leasehold position to drill longer length laterals with increased working interests. We also acquired proved developed reserves and undeveloped reserves in the Delaware Basin.

Extensions, discoveries and other additions for 2016 of 1.5 MMBoe includes the addition of five wells in the Utica Shale.

Acquisitions of reserves of 133.6 MMBoe includes proved developed producing properties and proved undeveloped ("PUD") locations acquired in our Delaware Basin acquisitions, and new proved locations obtained from an acreage exchange transaction. Because of the preferential economics of the more concentrated acreage in the Wattenberg Field, we rescheduled the timing of anticipated development in the field. This resulted in a downward revision to our proved reserves. The net downward revisions were 42.6 MMBoe. The revision was most notably attributed to a 61.0 MMBoe decrease in reserves due to 2015 PUD locations being removed from our five year development plan and being replaced by PUD locations reflected in purchases of reserves. Infill reserve additions of 16.8 MMBoe in the Wattenberg Field were included as a positive revision of previous estimates. Infill reserve additions for years prior to 2016 for the Wattenberg Field were reported in extensions, discoveries and other additions, including infill reserves in an existing proved field. Revisions also include a 0.5 MMBoe decrease on production due to pricing. The remaining 2.1 MMBoe in positive revisions of previous estimates includes performance revisions and other items.

We had minimal dispositions of 1.7 MMBoe related to acreage traded in the acreage exchange.

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SUPPLEMENTAL INFORMATION
(Unaudited)

At December 31, 2015, we projected a PUD reserve conversion rate of 19 percent for 2016. As a result of revisions to our drilling plan during the last two months of 2016, our actual reserve conversion rate was 16 percent, resulting in 32.2 MMBoe of reserves recorded as PUDs at December 31, 2015, being converted to proved developed reserves as of December 31, 2016.

Based on economic conditions on December 31, 2016, our approved development plan provides for the development of our remaining PUD locations within five years of the date such reserves were initially recorded. As of December 31, 2016, our 2017 PUD reserve conversion rate is expected to be approximately 26 percent. The balance of the PUD reserves are scheduled to be developed over the remaining four years in accordance with our current development plan. The level of capital spending necessary to achieve this drilling schedule is consistent with our recent performance and our outlook for future development activities.

2015 Activity. Overall, our proved reserves increased by 23 MMBoe as of December 31, 2015 as compared to December 31, 2014. In 2015, we produced 15.4 million MMBoe. At December 31, 2014, we projected a PUD conversion rate of 16 percent for 2015. Our actual conversion rate was 17 percent, resulting in 29 MMBoe of reserves booked as PUDs at December 31, 2014 being converted to proved developed reserves during 2015. As shown, we acquired and divested minimal volumes of proved reserves in 2015.

Extensions, discoveries, and other additions, including infill reserves, of approximately 131 MMBoe in 2015 were all added in the Wattenberg Field and primarily related to horizontal Niobrara projects being added to our development plan. The reserve additions associated with these projects are largely the result of data generated from our downspacing testing. This led to increased well density of our PUD locations year-over-year and extended the field by enabling us to book more reserves per section in the Niobrara. In general, at December 31, 2014, Niobrara PUD locations were booked at an equivalent of eight wells per section and at December 31, 2015, such locations were booked at an equivalent of 16 wells per section. Additionally, due to more efficient drilling leading to shorter spud-to-spud times, we have increased the number of wells drilled per drilling rig utilized during the course of the year. We have 791 gross PUD horizontal drilling locations at December 31, 2015, which is an increase from 774 locations at December 31, 2014. Approximately 9 MMBoe of the extensions, discoveries, and other additions to our developed reserves related to wells drilled that were not related to reserves booked as of prior year-end.

We recorded net downward revisions of previous estimates of proved reserves of approximately 93 MMBoe. The revision was a result of multiple factors, most notably a decrease of approximately 56 MMBoe for adjustments to our development plans in the Wattenberg Field resulting from the booking of further-downspaced PUD locations. This downspacing delayed the expected development date for many existing PUD locations beyond the limits of the SEC five-year rule. Also, contributing to the downward revision was a decrease of approximately 33 MMBoe due to the significant decrease in SEC commodity prices utilized in the December 31, 2015 reserve report, including approximately 11 MMBoe specifically related to the removal of vertical re-fracs and re-completions from the proved developed reserves which no longer fall within our economic parameters. There was an additional negative revision of approximately 22 MMBoe primarily related to geology findings and leasehold factors. Partially offsetting these decreases was an upward revision approximately 18 MMBoe related to well performance and forecast adjustments.

Based on the economic conditions on December 31, 2015, our approved development plan provides for the development of our remaining PUD reserves within five years of the date such reserves were initially recorded. The continued success of our increased well density tests in the Wattenberg Field in 2015 allowed for the additional increased well density of PUD locations as of December 31, 2015. Because we expect to continue to drill primarily proved Wattenberg Field locations in 2016 and as a result of additional newly-booked downspaced PUDs at December 31, 2015, our 2016 PUD conversion rate is expected to be approximately 19 percent. The balance of the locations are scheduled to be drilled over the remaining four years in accordance with our current development plan. The level of capital spending necessary to achieve this drilling schedule is consistent with our recent performance and our outlook for future development activities.

2014 Activity. Overall, our proved reserves decreased by 16 MMBoe as of December 31, 2014 as compared to December 31, 2013. In 2014, we produced 9.3 MMBoe. At December 31, 2013, we projected a PUD conversion rate of seven percent for 2014. Our actual conversion rate was seven percent, resulting in 13 MMBoe of reserves booked as PUDs at December 31, 2013 being converted to proved developed reserves during 2014. As shown, we acquired minimal proved reserves in 2014. We divested a total of 40 MMBoe in 2014, primarily from the sale of our Marcellus Shale assets.

Extensions, discoveries and other additions, including infill reserves, resulted in an increase of approximately 98 MMBoe in 2014, substantially all of which was added in the Wattenberg Field and primarily related to Niobrara and Codell projects. These reserve increases are primarily due to adding 78 MMBoe from new proved undeveloped reserves as a result of adjustments in well spacing, which extended the field by enabling us to book more reserves per section in the Niobrara and Codell formations. In addition, approximately 16 MMBoe of previously unbooked locations were developed in the current year and 2 MMBoe due to various other factors. Approximately 2 MMBoe was added in the Utica Shale.

We recorded a downward revision of our previous estimate of proved reserves of approximately 65 MMBoe. The revision was primarily related to decreases of approximately 55 MMBoe for adjustments to our development plans in the Wattenberg Field to focus on a more balanced commodity production mix and increased well density which delayed the expected development date for many existing PUD locations beyond the limits of the SEC five-year rule. In addition, 8 MMBoe of Utica Shale PUDs are no longer in our drilling plans as we directed more capital to higher-return projects in the Wattenberg Field and 2 MMBoe that were due to various other factors.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

Based on the economic conditions on December 31, 2014, our approved development plan provided for the development of our remaining PUD reserves within five years of the date such reserves were initially recorded. Our 2014 drilling program focused on testing increased well density in the Wattenberg Field.

Results of Operations for Crude Oil and Natural Gas Producing Activities

The results of operations for crude oil and natural gas producing activities are presented below. The results include activities related to both continuing and discontinued operations and exclude activities related to gas marketing and other income.

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Revenue:			
Crude oil, natural gas and NGLs sales	$ 497,353	$ 378,713	$ 495,562
Commodity price risk management gain (loss), net	(125,681)	203,183	309,219
	371,672	581,896	804,781
Expenses:			
Lease operating expenses	59,950	56,992	43,682
Production taxes	31,410	18,443	27,194
Transportation, gathering and processing expenses	18,415	10,151	8,128
Exploration expense	4,669	1,102	948
Impairment of properties and equipment	9,973	161,620	167,280
Depreciation, depletion, and amortization	413,105	298,760	201,656
Accretion of asset retirement obligations	7,080	6,293	3,455
Loss on sale of properties and equipment	(43)	(385)	(75,972)
	544,559	552,976	376,371
Results of operations for crude oil and natural gas producing activities before provision for income taxes	(172,887)	28,920	428,410
Provision for income taxes	64,733	(10,394)	(166,930)
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$ (108,154)	$ 18,526	$ 261,480

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance, production and severance taxes, and associated administrative expenses. DD&A expense includes those costs associated with capitalized acquisition, exploration, and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using effective tax rates.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

Costs Incurred in Crude Oil and Natural Gas Property Acquisition, Exploration, and Development Activities

Costs incurred in crude oil and natural gas property acquisition, exploration, and development are presented below.

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Acquisition of properties: (1)			
Proved properties (2)	$ 268,567	$ 3,561	$ 11,973
Unproved properties	1,843,985	15	45,999
Development costs (3)	383,336	552,104	608,176
Exploration costs: (4)			
Exploratory drilling	—	—	—
Geological and geophysical	4,669	—	1
Total costs incurred	$ 2,500,557	$ 555,680	$ 666,149

(1) Property acquisition costs represent costs incurred to purchase, lease or otherwise acquire a property.
(2) Includes approximately $40.9 million of infrastructure and pipeline costs in 2016.
(3) Development costs represent costs incurred to gain access to and prepare development well locations for drilling, drill and equip development wells, recomplete wells, and provide facilities to extract, treat, gather, and store crude oil, natural gas, and NGLs. Of these costs incurred for the years ended December 31, 2016, 2015, and 2014, $204.6 million, $207.8 million, and $125.2 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end.
(4) Exploration costs - represents costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing crude oil, natural gas, and NGLs.

Capitalized Costs Related to Crude Oil and Natural Gas Producing Activities

Aggregate capitalized costs related to crude oil and natural gas exploration and production activities with applicable accumulated DD&A are presented below:

	As of December 31,	
	2016	2015
	(in thousands)	
Proved crude oil and natural gas properties	$ 3,499,718	$ 2,881,189
Unproved crude oil and natural gas properties	1,874,671	60,498
Uncompleted wells, equipment and facilities	150,424	109,385
Capitalized costs	5,524,813	3,051,072
Less accumulated DD&A	(1,534,678)	(1,131,705)
Capitalized costs, net	$ 3,990,135	$ 1,919,367

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

The standardized measure below has been prepared in accordance with U.S. GAAP. Future estimated cash flows were based on a 12-month average price calculated as the unweighted arithmetic average of the prices on the first day of each month, January through December, applied to our year-end estimated proved reserves. Prices for each of the three years were adjusted by field for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity derivatives. Production and development costs were based on prices as of December 31 for each of the respective years presented. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service or to depreciation, depletion, and amortization expense. Production and development costs include those cash flows associated with the expected ultimate settlement of our asset retirement obligations. Future estimated income tax expense is computed by applying the statutory rate in effect at the end of each year to the projected future pre-tax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits, and allowances related to the properties.

The following table presents information with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Changes in the demand for crude oil, natural gas, and NGLs, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of our proved reserves.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

	As of December 31,		
	2016	2015	2014
	(in thousands)		
Future estimated cash flows	$ 7,122,525	$ 6,297,298	$ 12,550,515
Future estimated production costs*	(1,624,167)	(1,493,040)	(2,746,811)
Future estimated development costs	(2,219,914)	(2,036,685)	(2,528,755)
Future estimated income tax expense	(597,476)	(508,332)	(2,336,510)
Future net cash flows	2,680,968	2,259,241	4,938,439
10% annual discount for estimated timing of cash flows	(1,260,339)	(1,162,377)	(2,631,974)
Standardized measure of discounted future estimated net cash flows	$ 1,420,629	$ 1,096,864	$ 2,306,465

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* Represents future estimated lease operating expenses, production taxes, transportation, gathering and processing expenses.

The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Beginning of period	$ 1,096,864	$ 2,306,465	$ 1,782,163
Sales of crude oil, natural gas and NGLs production, net of production costs	(387,576)	(293,127)	(387,789)
Net changes in prices and production costs (1)	(205,760)	(1,752,921)	129,213
Extensions, discoveries, and improved recovery, less related costs	15,128	489,178	1,444,581
Sales of reserves	(3,745)	(463)	(402,595)
Purchases of reserves	487,636	374	238
Development costs incurred during the period	268,672	368,840	161,404
Revisions of previous quantity estimates	(320,286)	(1,286,462)	(654,318)
Changes in estimated income taxes	(13,630)	902,994	(221,874)
Net changes in future development costs	391,145	112,958	46,499
Accretion of discount	133,747	345,007	270,389
Timing and other	(41,566)	(95,979)	138,554
End of period	$ 1,420,629	$ 1,096,864	$ 2,306,465

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(1) Our weighted-average price, net of production costs per Boe, in our 2016 reserve report decreased to $15.73 as compared to $17.30 for 2015 and $37.78 for 2014.

The data presented should not be viewed as representing the expected cash flows from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the recent average prices and current costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

QUARTERLY FINANCIAL INFORMATION - UNAUDITED

Quarterly financial data for the years ended December 31, 2016 and 2015 is presented below. The quarterly consolidated statements of operations below reflect our revised presentation. The sum of the quarters may not equal the total of the year's net income or loss per share due to changes in the weighted-average shares outstanding throughout the year.

	2016			
	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share data)			
Total revenues	$ 90,831	$ 20,097	$ 163,890	$ 108,097
Total cost, expenses and other	193,864	163,379	179,178	178,608
Loss from operations	(103,033)	(143,282)	(15,288)	(70,511)
Loss before income taxes	(113,369)	(153,777)	(35,341)	(90,636)
Net loss	$ (71,530)	$ (95,450)	$ (23,309)	$ (55,639)
Earnings per share:				
Basic	$ (1.72)	$ (2.04)	$ (0.48)	$ (0.94)
Diluted	(1.72)	(2.04)	(0.48)	(0.94)

	2015			
	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share data)			
Total revenues	$ 144,632	$ 50,960	$ 231,100	$ 168,634
Total costs, expenses and other	106,235	117,514	283,047	152,354
Income (loss) from operations	38,397	(66,554)	(51,947)	16,280
Income (loss) before income taxes	27,785	(76,986)	(62,661)	5,274
Net income (loss)	$ 17,062	$ (46,870)	$ (41,494)	$ 3,022
Earnings per share:				
Basic	$ 0.47	$ (1.17)	$ (1.04)	$ 0.08
Diluted	0.46	(1.17)	(1.04)	0.07

FINANCIAL STATEMENT SCHEDULE

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1	Charged to Costs and Expenses	Deductions (1)	Ending Balance December 31
	(in thousands)			
2016:				
Allowance for uncollectible notes	$ —	$ 44,038	$ —	$ 44,038
Allowance for doubtful accounts	2,009	1,309	1,128	2,190
Allowance for expirations of unproved crude oil and natural gas properties	144	215	—	359
2015:				
Allowance for doubtful accounts	486	1,700	177	2,009
Allowance for expirations of unproved crude oil and natural gas properties	9,293	7,012	16,161	144
2014:				
Allowance for doubtful accounts	896	78	488	486
Allowance for expirations of unproved crude oil and natural gas properties	5,142	4,465	314	9,293

(1) *For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For allowance for expirations of unproved crude oil and natural gas properties, deductions represent accumulated amortization of expired or abandoned unproved crude oil and natural gas properties, with a corresponding decrease to the historical cost of the associated asset.*

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2016, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e). Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2016.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. 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. 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 policies or procedures may deteriorate.

In conducting our evaluation of the effectiveness of our internal control over financial reporting, we excluded the internal control over financial reporting and associated activities of the Delaware Basin acquisitions that were accounted for as a business combination, which were consolidated into our financial statements on December 6, 2016, due to the size of the acquisition and integration into our internal control structure which was in process as of December 31, 2016. These properties constituted 11 percent of total assets and one percent of total revenue of the consolidated financial statement amounts as of and for the year ended December 31, 2016. Such exclusion was in accordance with the SEC guidance that an assessment of a recently acquired business may be omitted in management's report on internal controls over financial reporting, providing the acquisition took place within twelve months of management's evaluation.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016, based upon the criteria established in "Internal Control – Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2016.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2016, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2017 Annual Stockholders' meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Exhibits:

See Exhibits Index on the following page.

ITEM 16. FORM 10-K SUMMARY

None.

Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference: Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
2.1	Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc. (the "Company").	8-K12B	001-37419	2.1	6/8/2015	
2.2	Stock Purchase and Sale Agreement, dated August 23, 2016, by and among the seller parties thereto, Kimmeridge Energy Management Company GP, LLC, Arris Petroleum Corporation, and PDC Energy, Inc.	8-K	001-37419	2.1	8/24/2016	
2.3	Asset Purchase and Sale Agreement, dated August 23, 2016, by and among 299 Resources, LLC, 299 Production, LLC, 299 Pipeline, LLC, Kimmeridge Energy Management Company GP, LLC and PDC Energy, Inc.	8-K	001-37419	2.2	8/24/2016	
3.1	Certificate of Incorporation of the Company.	8-K12B	001-37419	3.1	6/8/2015	
3.2	By-laws of the Company.	8-K12B	001-37419	3.2	6/8/2015	
4.1	Form of Common Stock Certificate of the Company.					X
4.2	Indenture, dated as of October 3, 2012, by and between the Company and U.S. Bank Trust National Association, as Trustee, including the form of 7.75% Senior Notes due 2022.	8-K	000-07246	4.1	10/3/2012	
4.3	Base Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee.	8-K	001-37419	4.1	9/14/2016	
4.4	First Supplemental Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee, relating to the 1.125% Convertible Senior Notes due 2021.	8-K	001-37419	4.2	9/14/2016	
4.5	Indenture, dated as of September 15, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee, relating to the 6.125% Senior Notes due 2024.	8-K	001-37419	4.1	9/15/2016	
10.1*	Form of Indemnification Agreement.	8-K	000-07246	10.1	6/8/2015	
10.2*	401(k) and Profit Sharing Plan, as amended on January 4, 2016.					X
10.3*	Amended and Restated Non-Employee Director Deferred Compensation Plan.	10-K	000-07246	10.3	2/21/2014	
10.4*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008 ("2004 Plan").	10-K	000-07246	10.26	2/27/2009	
10.4.1*	Summary of 2010 Stock Appreciation Rights and Restricted Stock Awards under the 2004 Plan.	8-K	000-07246		4/23/2010	
10.5*	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended.	10-K	001-37419	10.5	2/22/2016	
10.6*	Executive Severance Compensation Plan, as amended.	10-K	001-37419	10.6	2/22/2016	
10.7*	Form of 2011 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.2	2/21/2014	
10.7.1*	Form of 2013 Performance Share Agreement.	10-K	000-07246	10.9	2/27/2013	
10.7.2*	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.10	2/27/2013	
10.7.3*	Form of 2014 Performance Share Agreement.	10-K	000-07246	10.5.4	2/19/2015	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.7.4*	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.5	2/19/2015	
10.7.5*	Form of 2015 Performance Share Agreement.	10-K	000-07246	10.5.6	2/19/2015	
10.7.6*	Form of 2015 Restricted Stock Unit Agreement.	10-K	000-07246	10.5.7	2/19/2015	
10.7.7*	Form of 2015 Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.8	2/19/2015	
10.7.8*	Form of 2016 Performance Share Agreement.	10-K	001-37419	10.7.8	2/22/2016	
10.8*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of April 19, 2010.	8-K	000-07246	10.2	4/23/2010	
10.9*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010.	8-K	000-07246	10.3	4/23/2010	
10.10*	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010.	8-K	000-07246	10.4	4/23/2010	
10.11	Third Amended and Restated Credit Agreement dated as of May 21, 2013, among PDC Energy, Inc. as Borrower, Riley Natural Gas Company, a Subsidiary of PDC Energy, Inc., as Guarantor, JP Morgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities LLC as Sole Bookrunner and Co-Lead Arranger, Wells Fargo Bank, N.A. as Syndication Agent, and Wells Fargo Securities, LLC as Co-Lead Arranger, and Certain Lenders.	8-K	000-07246	10.1	5/28/2013	
10.11.1	First and Second Amendments to Third Amended and Restated Credit Agreement dated as of May 14, 2014 and September 30, 2015, respectively, among PDC Energy, Inc. as the Borrower, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders.	10-K	001-37419	10.11.1	2/22/2016	
10.11.2	Third Amendment to the Third Amended and Restated Credit Agreement, dated as of September 6, 2016, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders.	8-K	001-37419	10.1	9/8/2016	
10.11.3	Fourth Amendment to the Third Amended and Restated Credit Agreement, dated as of October 14, 2016, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders.	10-Q	001-37419	99.1	11/3/2016	
10.12*	Consulting Agreement with James M. Trimble, dated as of June 18, 2014.	10-Q	000-07246	10.1	8/8/2014	
10.13*	Retirement Agreement with Gysle R. Shellum, Chief Financial Officer, dated October 26, 2015.	8-K	001-37419	10.1	10/27/2015	
10.14*	Change of Control and Severance Plan.					X
10.14.1*	Amendment to the PDC Energy Change of Control and Severance Plan			10.14.1	2/28/2017	X
10.15	Registration Rights Agreement, dated as of September 15, 2016, by and between PDC Energy, Inc. and J.P. Morgan Securities LLC, as representative of the initial purchasers, relating to the 6.125% Senior Notes due 2024.	8-K	001-37419	10.2	9/5/2016	
10.16	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Stock Purchase and Sale Agreement).	8-K	001-37419	10.1	12/7/2016	
10.17	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Asset Purchase and Sale Agreement).	8-K	001-37419	10.2	12/7/2016	
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
21.1	Subsidiaries.					X

23.1	Consent of PricewaterhouseCoopers LLP.	X
23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.	X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
23.3	Consent of Netherland, Sewell & Associates, Inc., Petroleum Consultants.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1**	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
99.1	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.					X
99.2	Report of Independent Petroleum Consultants - Netherland, Sewell & Associates, Inc.					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

*Management contract or compensatory arrangement.

** Furnished herewith.

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.

PDC ENERGY, INC.

By: /s/ Barton R. Brookman

Barton R. Brookman

President and Chief Executive Officer

February 28, 2017

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/ Barton R. Brookman Barton R. Brookman	President, Chief Executive Officer and Director (principal executive officer)	February 28, 2017
/s/ David W. Honeyfield David W. Honeyfield	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2017
/s/ R. Scott Meyers R. Scott Meyers	Chief Accounting Officer (principal accounting officer)	February 28, 2017
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Chairman and Director	February 28, 2017
/s/ Joseph E. Casabona Joseph E. Casabona	Director	February 28, 2017
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 28, 2017
/s/ Larry F. Mazza Larry F. Mazza	Director	February 28, 2017
/s/ David C. Parke David C. Parke	Director	February 28, 2017
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	February 28, 2017

GLOSSARY OF UNITS OF MEASUREMENT AND INDUSTRY TERMS

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One barrel of crude oil or NGL or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Boe – One barrel of crude oil equivalent.
Btu – British thermal unit.
BBtu – One billion British thermal units.
MBoe – One thousand barrels of crude oil equivalent.
MBbls – One thousand barrels of crude oil.
Mcf – One thousand cubic feet of natural gas volume.
MMBoe – One million barrels of crude oil equivalent.
MMBbls – One million barrels of crude oil.
MMBtu – One million British thermal units.
MMcf – One million cubic feet of natural gas volume.

GLOSSARY OF INDUSTRY TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report:

CIG - Colorado Interstate Gas.

Completion - Refers to the installation of permanent equipment for the production of crude oil and natural gas from a recently drilled well or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Developed acreage - Acreage assignable to productive wells.

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

Differentials - The difference between the crude oil and natural gas index spot price and the corresponding cash spot price in a specified location.

Dry gas or dry natural gas - Natural gas is considered dry when its composition is over 90 percent pure methane.

Dry well or dry hole - A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

Exploratory well - A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extensions and discoveries - As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Farm-out - Transfer of all or part of the operating rights from a working interest owner to an assignee, who assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty interest but may retain any type of interest.

Fracture or *Fracturing* - Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity, thereby allowing the release of trapped hydrocarbons.

Gross acres or *wells* - Refers to the total acres or wells in which we have a working interest.

Horizontal drilling - A drilling technique that permits the operator to drill a horizontal well shaft from the bottom of a vertical well and thereby to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Joint interest billing - Process of billing/invoicing the costs related to well drilling, completions, and production operations among working interest partners.

Natural gas liquid(s) or *NGL(s)* - Hydrocarbons which can be extracted from natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs include ethane, propane, butane, and other natural gasolines.

Net acres or *wells* - Refers to gross acres or wells we own multiplied, in each case, by our percentage working interest. References to net acres or wells include our proportionate share of PDCM's and our affiliated partnerships' net acres or wells.

Net production - Crude oil and natural gas production that we own, less royalties and production due to others.

Non-operated - A project in which we are not the operator.

NYMEX - New York Mercantile Exchange.

Operator - The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Overriding royalty - An interest which is created out of the operating or working interest. Its term is coextensive with that of the operating interest.

Possible reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability to exceed the sum of proved, probable, and possible reserves. When probabilistic methods are used, there must be at least a 10 percent probability that the actual quantities recovered will equal or exceed the sum of proved, probable and possible estimates.

Present value of future net revenues or *(PV-10)* - The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, of proved reserves calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using pricing and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10 percent. PV-10 is pre-tax and therefore a non-U.S. GAAP financial measure.

Probable reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Similarly, when probabilistic methods are used, there must be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Productive well - An exploratory or developmental well that is not a dry well or dry hole, as defined above.

Proved developed non-producing reserves - Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and/or (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves or *PDPs* - Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

Proved reserves - This term means "proved oil and gas reserves" as defined in SEC Regulation S-X Section 4-10(a) and refers to those quantities of crude oil and condensate, natural gas, and NGLs, 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 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.

Proved undeveloped reserves or *PUDs* - 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.

Recomplete or *Recompletion* - The modification of an existing well for the purpose of producing crude oil and natural gas from a different producing formation.

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

Royalty - An interest in a crude oil and natural gas lease or mineral interest that gives the owner of the royalty the right to receive a portion of the production from the leased acreage or mineral interest (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Section - A square tract of land one mile by one mile, containing 640 acres.

Spud - To begin drilling; the act of beginning a hole.

Standardized measure of discounted future net cash flows or *standardized measure* - Future net cash flows discounted at a rate of 10 percent. Future net cash flows represent the estimated future revenues to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment and (ii) future income tax expense.

Stratigraphic test well - A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

TETCO M2 - Texas Eastern Transmission Corporation M-2 receipts.

Undeveloped acreage - Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether such acreage contains proved reserves.

Waha - Waha West Texas natural gas prices

Wet gas or wet natural gas - Natural gas that contains a larger quantity of hydrocarbon liquids than dry natural gas, such as NGLs, condensate and crude oil.

Working interest - An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill and produce crude oil and natural gas on the leased acreage. It requires the owner to pay its share of the costs of drilling and production operations.

Workover - Major remedial operations on a producing well to restore, maintain, or improve the well's production.