PDC ENERGY

YEAR-END 2015
1.4x
DEBT TO EBITDAX[1]

BOE/D
42,100
DAILY PRODUCTION

YEAR-OVER-YEAR
65%
PRODUCTION INCREASE [2]

BBLS/D
19,130
DAILY OIL PRODUCTION

MMBOE
273
YEAR-END 2015
PROVED RESERVES

YEAR-OVER-YEAR
74%
CASH FLOW FROM
OPERATIONS INCREASE

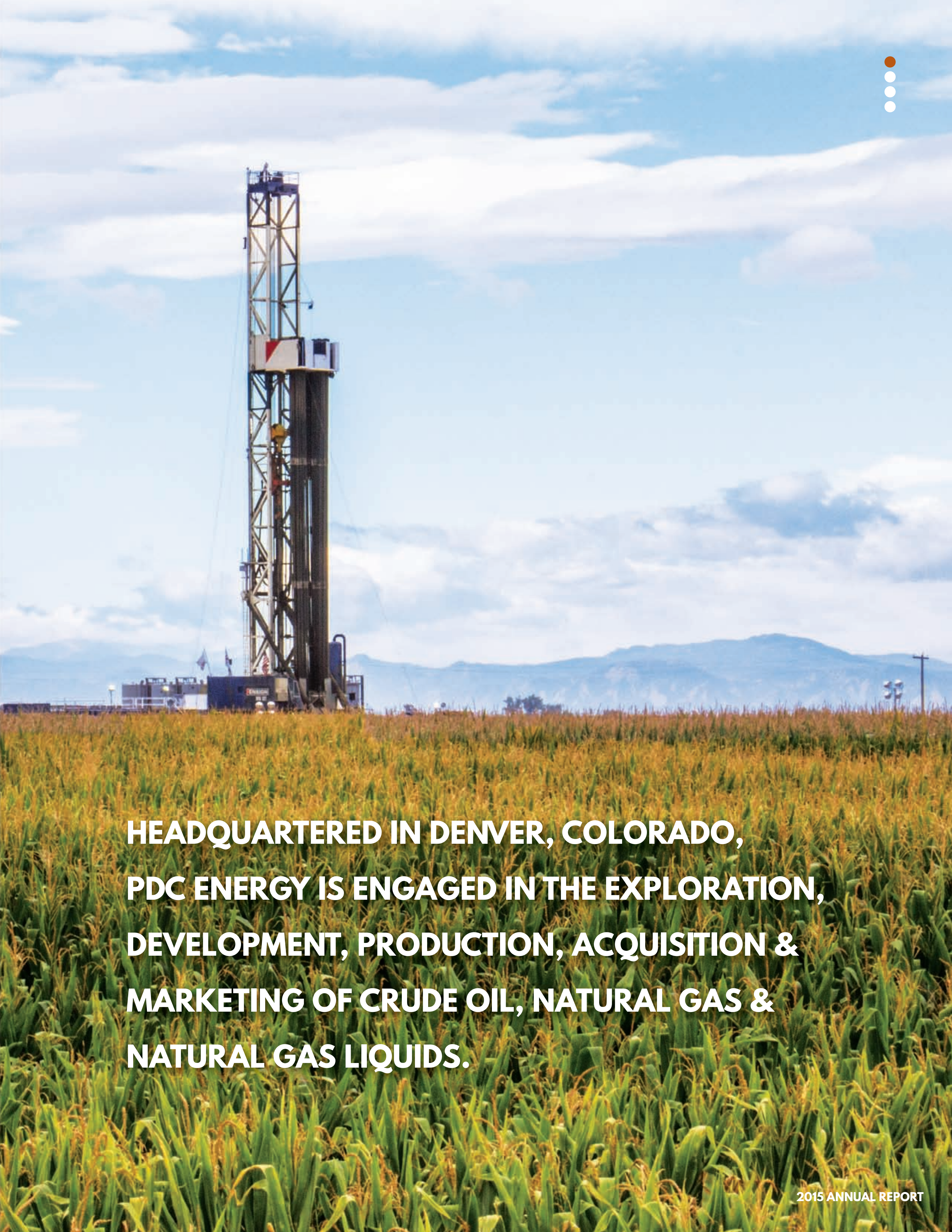
OPERATING DATA

As of December 31,	**2015**	**2014**	**2013**
PROVED RESERVES			
Crude Oil and Condensate (MMBbls)	99	101	94
Natural Gas (Bcf)	661	537	740
NGLs (MMBbls)	64	60	49
Total Proved Reserves (MMBoe)	273	250	266
CRUDE OIL, NATURAL GAS AND NGLS OPERATIONS PRODUCTION			
Crude oil (MMBbls)	7.0	4.3	2.9
Natural gas (Bcf)	33.3	19.3	15.4
NGLs (MMBbls)	2.8	1.8	1.0
Total Production (MMBoe)	15.4	9.3	6.5
AVERAGE SALES PRICE			
Crude oil (per Bbl)	$40.14	$80.67	$89.92
Natural gas (per Mcf)	2.04	3.87	3.24
NGLs (per Bbl)	10.72	27.39	27.97
Crude oil equivalent (per Boe)	24.64	50.72	52.23
Lease Operating Expenses (per Boe)	$3.71	$4.56	$5.18
DD&A expense related to crude oil and natural gas (per Boe)	$19.44	$20.28	$17.05

SELECT FINANCIAL DATA

Year Ended December 31, (in millions except per share amounts)	**2015**	**2014**	**2013**
STATEMENT OF OPERATIONS			
Crude oil, natural gas and NGLs sales	$378.7	$471.4	$340.8
Commodity price risk management gain (loss), net	203.2	310.3	(23.9)
Total Revenues	595.3	856.2	392.7
Net income (loss)	(68.3)	155.4	(22.3)
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO SHAREHOLDERS			
Net income (loss)	$(1.74)	$4.24	$(0.69)
STATEMENT OF CASH FLOWS			
Net cash provided by operating activities	$411.1	$236.7	$159.2
Capital expenditures	604.7	628.6	394.9
Acquisitions	-	-	9.7
BALANCE SHEET			
Total assets	$2,370.5	$2,331.1	$1,991.7
Total debt	642.4	655.5	593.9
Equity	1,287.2	1,137.4	967.6
Total Debt to Capital Ratio	33%	37%	38%

[1] EBITDAX is adjusted EBITDA plus exploration expense, excludes gain/loss on sale of assets
[2] Production from continuing operations



HEADQUARTERED IN DENVER, COLORADO, PDC ENERGY IS ENGAGED IN THE EXPLORATION, DEVELOPMENT, PRODUCTION, ACQUISITION & MARKETING OF CRUDE OIL, NATURAL GAS & NATURAL GAS LIQUIDS.

DEAR SHAREHOLDERS,

In the oil and gas industry, certain years are etched into our collective memory. Given the dramatic collapse in global commodity prices, there is no doubt 2015 will be remembered as such a year.

At PDC, as we watched crude oil and natural gas prices decline, we continued to employ an extremely disciplined business approach, with a primary focus on our balance sheet. We were able to increase our reserves and attain peer-leading production growth, while maintaining our financial strength, preserving liquidity and building a significant hedge position. These accomplishments truly set PDC apart as a premier domestic exploration and production company in 2015.

Our 2015 success would not have been possible without the tireless efforts of our dedicated employees. We are proud to have such a talented and experienced team, committed to safe and responsible operations. Our Environmental, Health & Safety and Operations departments strive to ensure we operate with integrity and in a safe and environmentally sound manner. We also make every effort to be a respected community partner, with our Community Relations group dedicated to contributing to and improving our local communities.

We are fortunate to have a large inventory of low-risk drilling opportunities with top tier economics, a fortress-like balance sheet and an active and robust risk management program (yielding one of the strongest hedge positions in the industry) allowing us to continue delivering long term shareholder value.

We remain committed to looking at our business strategically as market conditions change, including reviewing our strategic plan quarterly to ensure we are maintaining our financial strength and flexibility.

In 2015, our increased emphasis on cash flow neutrality resulted in cash flow exceeding capital expenditures in the second half of the year. Importantly, we ended 2015 with a year-end debt to EBITDAX ratio of 1.4 times, and a financial position we believe is capable of sustaining PDC through a prolonged low price environment.

PDC's 2015 production of 15.4 million barrels of oil equivalent represents 65% growth over 2014 levels, and illustrates the quality of our core Wattenberg assets. We began 2015 with several technological initiatives aimed at increasing our productivity on a per-well basis and improving our capital efficiency. These advancements, including tighter spacing between frac stages, extended-reach lateral drilling, continued downspacing tests and plug-n-perf completions, have all yielded early encouraging results. In 2015, we saw drilling and completion costs drop over 30% from 2014, due in part to a 50% improvement in drilling times – ultimately preserving economics in this low oil-price environment.

We view 2016 as an opportunity to differentiate PDC as a premier exploration and production company.

RESILIENT ASSET BASE

EXPERIENCED MANAGEMENT TEAMS

STRONG BALANCE SHEET

PDC's operating plan for 2016 continues to focus on balance sheet strength and cash flow neutrality. We anticipate our ability to drive down costs and preserve acceptable margins will support our goals of financial discipline coupled with strong growth. To further aid these objectives, the Company enters the year with a substantial portion of expected 2016 production volumes hedged well above current market prices.

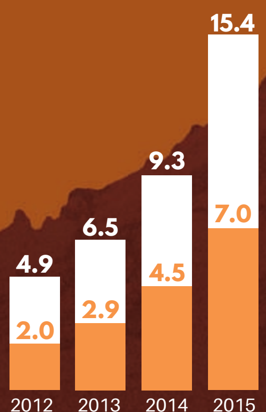
In 2016, we expect continued production growth due to profitable drilling programs and ongoing technical innovations. We have several more initiatives planned in 2016, including two-mile laterals, re-engineered completions in the Wattenberg, and a 10,000 foot lateral in our Utica shale position. These technical enhancements combined with our approximately 2,150 proved and probable drilling locations should enable PDC to continue delivering value-added growth into the future.

Entering 2016, we believe the company is well positioned to thrive through these incredibly uncertain times. We thank you for your continued support and confidence in the future of PDC Energy.

BARTON R. BROOKMAN
President and Chief Executive Officer

JEFFREY C. SWOVELAND
Non-Executive Chairman of the Board

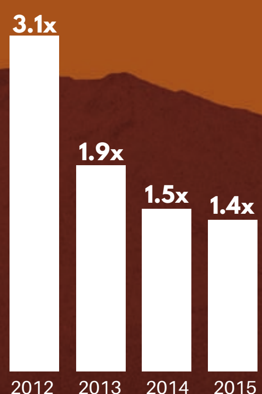
STRONG PRODUCTION GROWTH



Total Production (MMBoe)*
Oil Production (MMBbls)

* Production from continuing operations

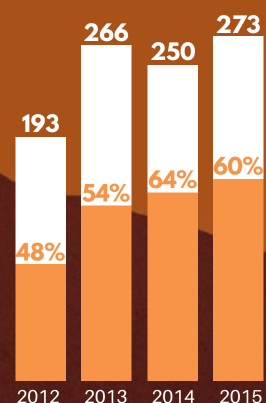
RESILIENT BALANCE SHEET



Debt to EBITDAX*

*EBITDAX is adjusted EBITDA plus exploration expense, excludes gain/loss on sale of assets

PROVED RESERVES

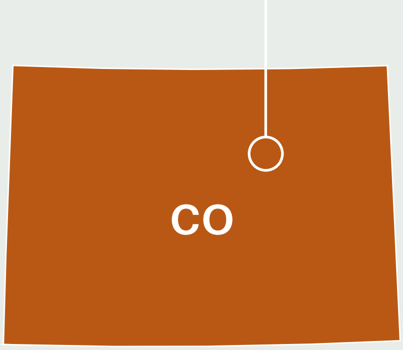


Total Proved Reserves (MMBoe)*
% Liquid

* Production from continuing operations

WATTENBERG

2015 NET ACREAGE: 96,000 ACRES



BOE/D

38,990

2015 PRODUCTION

2,150 – Proved & Probable Drilling Locations in Inventory

2016 – Testing Several Key Initiatives

BOE/D

3,115

2015 PRODUCTION

UTICA

2015 NET ACREAGE: 65,000 ACRES

PDC has two high-quality assets – the Core Wattenberg Field and the Utica Shale – that provide a solid foundation for future production growth and technical development. In 2015, the Company grew its annual production from these assets by 65% and increased its year-end proved reserves by nearly 10%, from 250 MMBoe to 273 MMBoe in 2014.

THE CORE WATTENBERG FIELD

The Wattenberg Field is located in Weld County in the Denver-Julesburg ("DJ") Basin. The 96,000 net acres represents the Company's largest asset with over 93% of 2015 production and 99% of 2015 proved reserves. PDC is currently the third largest leaseholder and producer in the Core Wattenberg. The Core Wattenberg Field ranks as one of the top rate-of-return horizontal plays in the U.S. onshore and has proven extremely resilient enabling the Company to provide value-driven growth even in the depressed commodity price environment in 2015.

PDC's Wattenberg acreage is nearly all held-by-production, with approximately 2,300 legacy vertical wells. The Company's year-end 2015 reserves included 791 proved undeveloped horizontal locations and approximately 2,150 proved and probable (2P) locations in inventory. With this depth of inventory and at our current drilling pace, PDC has more than a decade of drilling in this liquid-rich basin.

From a technical standpoint in Wattenberg, 2015 proved to be very successful as the Company implemented tighter spacing between frac intervals on all wells and began several different tests designed to increase per well performance and efficiency. These tests included drilling wells with longer laterals of 6,500' to 7,000' and various completion methods, including plug-and-perf technology and using a diverting agent. Additionally, the Company increased drilling efficiencies by reducing average spud-to-spud drill times for a standard length lateral well from 14 to seven days. In total, PDC spud 174 gross horizontal wells and turned-in-line 136 wells in Wattenberg in 2015.

In 2016, the Company plans to continue to pursue drilling efficiencies and per well recoveries. Current plans include drilling extended reach lateral wells of 9,500' to 10,000', continued testing of completion technologies, and the evaluation of downspacing tests performed in 2015. These downspacing tests are aimed at determining the most effective and efficient way to capture the large oil and gas resources in-place.

THE UTICA SHALE

In its Utica asset in southeastern Ohio, the Company has approximately 65,000 net acres and continues to improve upon its early results. In 2015, PDC turned-in-line four wells which were drilled in 2014 and these wells delivered positive data in the northern part of its acreage position. In 2016, PDC plans to drill, complete and turn-in-line five wells with the goals of gathering technical data in the southern portion of its acreage, testing well-orientation and testing a 10,000' lateral in contrast to its standard 6,000' lateral.

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015

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 ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☒ 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 ☒

The aggregate market value of our common stock held by non-affiliates on June 30, 2015 was $2.1 billion (based on the closing price of $53.64 per share as of the last business day of the fiscal quarter ending June 30, 2015).

As of February 1, 2016, there were 40,269,891 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 2016 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2015 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 affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture owned 50% each by PDC and Lime Rock Partners, LP until its sale in October 2014. Unless the context otherwise requires, references in this report to "Appalachian Basin" refers to our operations in the Utica Shale in Ohio and Marcellus Shale in West Virginia and Pennsylvania, including PDC's proportionate share of our affiliated partnerships' and PDCM's assets, results of operations, cash flows and operating activities. See Note 1, *Nature of Operations and Basis of Presentation,* to our consolidated financial statements included elsewhere in this report for a description of our consolidated subsidiaries and Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations*, for a discussion of the sale of our interest in PDCM. 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 and incorporated by reference into 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. These statements relate to, among other things: estimated future production (including the components of such production), sales, expenses, cash flows, liquidity and balance sheet attributes; estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves; the impact of prolonged depressed commodity prices including potentially reduced production and associated cash flow; anticipated 2016 capital projects, expenditures and opportunities, including our expectation that 2016 cash flows from operations will approximate cash flows from investing activities; expected 2016 capital budget allocations; our operational flexibility and ability to revise our 2016 development plan; availability of sufficient funding and liquidity for our 2016 capital program and sources of that funding; expected losses of Riley Natural Gas ("RNG") through 2022 and expected discontinuation of RNG's business; future exploration, drilling and development activities, including non-operated activity, the number of drilling rigs we expect to run during 2016, number of locations and lateral lengths; opportunity in the Utica Shale to add reserves in a more favorable price environment; capital efficiencies and per well reserves expected to be realized; expected 2016 production and cash flow ranges; our evaluation method of our customers' and derivative counterparties' credit risk; effectiveness of our derivative program in providing a degree of price stability; future horizontal drilling locations that are economically producible at certain commodity prices and costs; potential for future impairments; potential acquisitions of additional acreage and other future transactions; electronic, cyber or physical security breaches; the impact of high line pressures and the timing, availability, cost and effect of additional midstream facilities and services going forward; compliance with debt and senior notes covenants; expected funding sources for conversion of our 3.25% convertible senior notes due 2016; compliance with government regulations; impact of the Colorado task force on oil and gas regulation and potential future ballot initiatives and legislation; the level of our borrowing base under our credit facility; impact of litigation on our results of operations and financial position; the adequacy of existing insurance to cover operating hazards and the availability of such insurance on a cost effective basis in the future; that we hold good and defensible title to our leasehold; that we do not expect to pay dividends in the foreseeable future; and our future strategies, plans and objectives.

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 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 reserve estimates and expected 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;
- 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 expenditures;
- 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 produces, develops, acquires and explores for crude oil, natural gas and NGLs with operations in the Wattenberg Field in Colorado and the Utica Shale in southeastern Ohio. Our 2016 drilling and completion operations in the Wattenberg Field are expected to focus on the middle core area of the Niobrara and Codell plays. As of December 31, 2015, we own an interest in approximately 3,000 gross producing wells, of which approximately 650 are horizontal. Production of 15.4 MMboe for the year ended December 31, 2015 represents an increase of 65% compared to the year ended December 31, 2014. For the month ended December 31, 2015, we maintained an average production rate of 52 MBoe per day. We were able to achieve this strong growth rate while maintaining a liquidity position of $402.2 million as of December 31, 2015 and a debt to EBITDAX ratio, as defined in our revolving credit facility agreement, of 1.4 times. As of December 31, 2015, we had approximately 273 MMBoe of proved reserves (26% of which are proved developed). Proved reserves at December 31, 2015 were comprised of approximately 60% liquids and 40% natural gas, and represent an increase of 23 MMBoe relative to December 31, 2014. Our proved reserve additions were primarily a result of the increased well density of proved undeveloped locations in the middle core area of the Niobrara formation in the Wattenberg Field, which allowed for the optimization of our five-year development plan. While the significant decrease in SEC commodity prices utilized in the 2015 year-end reserve report had a minimal impact on our quantities of proved reserves, this decrease in pricing resulted in a 61% decline in the pre-tax present value of future net revenues (“PV-10”) relative to December 31, 2014. PV-10 is not a financial measure under accounting principles generally accepted in the United States of America (“U.S. GAAP”). 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 our standardized measure.

Our Strengths

- ***Multi-year project inventory in premier crude oil, natural gas and NGLs plays.*** We have a significant operational presence in the Wattenberg Field, a key U.S. onshore basin, and have identified a substantial inventory of 791 gross proved undeveloped horizontal drilling locations and approximately 1,400 probable horizontal drilling locations in this play. These location counts are based on wells expected to be drilled with an average lateral length of approximately 4,700 feet. Further, with our leaseholds in Ohio, we have the ability to pursue developmental drilling in the emerging Utica Shale play and are focusing our development in the condensate and wet natural gas window of the play. We believe that this inventory will allow us to continue to grow our reserves and production, and that, with respect to the Wattenberg Field in particular, the majority of our projects will generate attractive rates of return at current commodity price projections and our current projected cost structure.

- ***Strong liquidity position.*** As of December 31, 2015, we had a total liquidity position of $402.2 million, comprised of $0.9 million of cash and cash equivalents and $401.3 million available for borrowing under our revolving credit facility. We had $37.0 million outstanding on our revolving credit facility as of December 31, 2015. Our liquidity position will be reduced by $115 million upon the maturity of our 3.25% convertible senior notes in May 2016. Pursuant to the related indenture, we will settle the principal amount of the notes in cash and issue common stock for the excess conversion value upon maturity. In September 2015, we completed the semi-annual redetermination of the borrowing base under our revolving credit facility, which resulted in the reaffirmation of the borrowing base at $700 million. We elected to maintain the aggregate commitment at $450 million. Considering the additional $250 million borrowing base available under our revolving credit facility, subject to certain terms and conditions of the agreement, our liquidity position as of December 31, 2015 could have been $652.2 million.

- ***Significant control in our core areas.*** Our operational control is enhanced by the fact that substantially all of our Wattenberg Field leasehold position is held-by-production. We remain flexible in terms of rig activity and capital deployment due to short-term rig contracts and held-by-production acreage. As a result, we can adjust our drilling plans if commodity prices deteriorate further in order to balance cash flows from operations and cash flows from investing activities, which primarily consist of our capital expenditures. 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. Additionally, as a result of successfully executing our strategy of acquiring largely concentrated acreage positions with a high working interest, we operate and manage approximately 87% of the wells in which we have an interest. Our high percentage of operated properties enables us to exercise a significant level of control with respect to drilling, production, operating and administrative costs, in addition to leveraging our base of technical expertise in our core operating areas.

- ***2016 derivative program.*** We have hedged a portion of our short-term future exposure to commodity price fluctuations by entering into crude oil and natural gas collars, fixed-price swaps and basis protection swaps. While our derivative program limits the upside benefits we may otherwise receive during periods of higher commodity prices, the program helps protect our cash flows, borrowing base and liquidity during periods of depressed commodity prices. As of December 31, 2015, we had hedge positions covering approximately 4,140 MBbls of 2016 crude oil production, or approximately 45% to 50% of our expected crude oil production for the year. These hedges were at a weighted-average minimum price of $77.26 per Bbl and a weighted-average maximum price of $86.88 per Bbl. As of the same date, we had hedged approximately 29.8 Bcf, or approximately 59% to 65%, of our expected natural gas production in 2016, at a weighted-average minimum price of $3.62 per Mcf and a weighted-average maximum price of $3.72 per Mcf. As of December 31, 2015, we had hedged a much lower percentage of our expected production for the next 12 to 24 months than we have hedged historically.

- ***Technology focused team.*** We have a proven track record of continuing improvement in both costs and productivity of our well operations. Recently, our teams have focused on transitioning to multi-well pad drilling, extended laterals, increased frac stage density, enhanced frac design and drilling efficiencies. In 2015, we introduced tighter frac stage density and, in 40% of our spuds, extended reach laterals that are 6,500 to 7,000 feet in length. We also began testing plug-and-perf completions along with diverting agents that have provided an uplift to our new well production. We have completed wells at various densities ranging from 16 wells per section equivalent to 26 wells per section equivalent, providing added information on the reserves that can potentially be recovered. Finally, our drilling team has made great strides in reducing drill times for one mile laterals from an average of approximately 14 days to seven days spud-to-spud over the year.

- ***Track record of reserve and production growth.*** Our proved reserves have grown from 50 MMBoe at December 31, 2010, after adjusting for subsequent divestitures, to approximately 273 MMBoe at December 31, 2015, representing a compound annual growth rate ("CAGR") of 40%. During the same time period, our proved crude oil and NGL reserves grew at a CAGR of 42%. Our annual production from continuing operations grew from 3.3 MMBoe in 2010 to 15.4 MMBoe in 2015, representing a CAGR of 36%. Future development of the Wattenberg Field provides the opportunity to add further proved, probable and possible reserves to our portfolio. Similarly, we believe the Utica Shale provides the opportunity for additional proved, probable and possible reserves in a more favorable crude oil and natural gas pricing environment. As a result of data generated from our downspacing testing in the Wattenberg Field, Ryder Scott Company, L.P. ("Ryder Scott"), our independent petroleum engineering consulting firm, has increased the density of our proven undeveloped locations, year-over-year, in the Niobrara formation. In general, at December 31, 2013, Niobrara PUD locations were booked at an equivalent density of six wells per section, at December 31, 2014, Niobrara PUD locations were booked at an equivalent density of eight wells per section and at December 31, 2015, Niobrara PUD locations are booked at the equivalent density of 16 wells per section.

- ***Strong environmental health and safety compliance programs.*** We have focused on establishing effective environmental health and safety programs that are able to earn trust and respect from 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, and in working with the local communities in which we operate.

- ***Community participation and outreach.*** We are 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. We also encourage our employees to take an active role through our charitable matching contribution fund and by participating in our "Energizing Our Community" day, during which our employees volunteer in the communities in which they work and live.

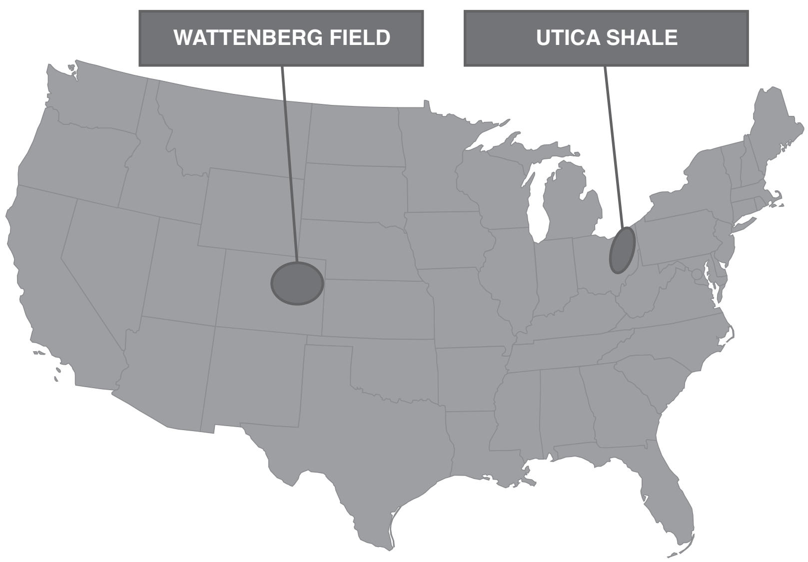
Business Strategy

Our long-term business strategy focuses on generating shareholder value through the development, acquisition and exploration of crude oil and natural gas properties. We are currently focused on the organic growth of our reserves, production and cash flows in our horizontal drilling programs after having completed multiple transactions in recent years to restructure and simplify our property portfolio. We pursue various midstream, marketing and cost reduction initiatives designed to increase our per unit operating margins while maintaining a conservative and 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 the current commodity price environment. Our current inventory of drilling locations supports our planned organic growth over the next several years. We expect it to drive increases in reserves, production and cash flows. In addition to development drilling, we routinely review acquisition and acreage swap opportunities in our core areas of operation as we believe we can extract additional value from such assets through production optimization and increasing our working interest in our development drilling locations. As a result, these types of core acquisitions and acreage swaps can potentially provide synergies that result in economies of scale. We also pursue a limited, but 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, 2015:



Our leasehold interests consist of developed and undeveloped crude oil, natural gas and NGLs resources. Based upon well cost savings resulting from the continued deterioration of commodity prices, our current 2016 capital forecast is a range between $420 million and $450 million. We have allocated over 90% of our 2016 capital forecast to our higher-return projects in the Wattenberg Field, primarily in the middle core area. We may decrease our 2016 capital forecast during the year as a result of, among other things, a further decline in commodity prices, a reduction of our current internal outlook for commodity prices, drilling results, unfavorable changes in our borrowing capacity and/or a significant decline in cash flows.

Wattenberg Field. Our primary focus in the Wattenberg Field is drilling in the horizontal Niobrara and Codell plays. Based on our current drilling program, we have an inventory of 791 gross proved undeveloped horizontal drilling locations and approximately 1,400 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 2016, we expect to continue to realize additional capital efficiencies through drilling extended length laterals, use of a diverting agent with plug-and-perf completions, 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 2016, the majority of which will be in the middle core area of the field. In 2016, we plan to spud 135 and turn-in-line approximately 160 horizontal Niobrara or Codell 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	11	14
Estimated percentage of 2016 wells spud	36%	34%	30%
Estimated percentage of 2016 wells turned-in-line	50%	40%	10%
Estimated cost per well (in millions)(1)	$2.6	$3.6	$4.6

(1) Estimated well costs include plug-and-perf technology.

The 2016 capital forecast anticipates a four-rig drilling program in the Wattenberg Field based on our current commodity price outlook. Approximately $400 million of our 2016 capital forecast is expected to be spent on development activities in the Wattenberg Field, comprised of approximately $350 million for our operated drilling program and approximately $35 million for non-operated projects. The remainder of the Wattenberg Field capital forecast is expected to be used for leasing, workover projects and other capital improvements, including the remodeling of our new field office in Greeley, Colorado. We expect to participate in approximately 35 gross, 7.0 net, non-operated horizontal opportunities in 2016.

Utica Shale. Our operations in the Utica Shale are currently less significant, and include horizontal drilling locations in the condensate and wet natural gas window of the play. In early 2015, based upon low commodity prices and large natural gas price differentials in Appalachia, we elected to temporarily cease drilling in the Utica Shale and limited our activity to completing and turning-in-line a four-well pad that was in process as of December 31, 2014. Due to a further significant decline in commodity prices and a decrease in net-back realizations, in the third quarter of 2015 we recorded an impairment charge of $150.3 million to write-down our Utica Shale producing and non-producing crude oil and natural gas properties. Based on the production results from our most recently drilled wells and the significant decrease in well costs, in 2016 we plan on executing a modest drilling operation in the condensate and wet natural gas window of the play. Early in 2016, we plan to spend approximately $35 million in the Utica Shale to drill, complete and turn-in-line five wells, all of which will have laterals of at least 6,000 feet. The planned activity will focus on further delineation of our southern acreage, determining the impact of well-orientation on productivity and testing improved capital efficiency of a 10,000 foot lateral length well.

While we expect to outspend our cash flows from operations during the first half of 2016, we believe that our cash flows from operations will exceed our cash flows from investing activities, which primarily consist of our capital expenditures, in the second half of 2016. As a result, we expect our overall 2016 cash flows from operations to approximate our cash flows from investing activities. However, a further deterioration of commodity prices could negatively impact our results of operations, financial condition and future development plans. We may decrease our 2016 capital forecast during the year as a result of, among other things, a further decline in commodity prices, drilling results, unfavorable changes in our borrowing capacity and/or a significant decline in cash flows. If commodity pricing falls short of our internal expectations, we would likely look to reduce our capital investment in the second quarter of 2016 to maintain our goal of capital expenditures approximating operational cash flows. We may change our capital expenditure plans from time to time for other reasons as well, including as a result of regulatory issues, drilling results or acquisition or divestiture opportunities. Our liquidity position will be reduced by the cash payment of approximately $115 million upon the maturity of our 3.25% convertible senior notes in May 2016. See Part I, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations - 2016 Operational Flexibility,* for additional information.

Operational and financial risk management

We proactively employ strategies to help reduce the financial risks associated with our industry. One such strategy is to utilize commodity-based derivative instruments to manage a portion of our short-term exposure to price volatility with regard to our crude oil and natural gas sales and natural gas marketing segments. As of December 31, 2015, we had natural gas and crude oil derivative positions in place for 2016 covering approximately 4,140 MBbls of our crude oil production and approximately 29.8 Bcf of our natural gas production and for 2017 covering approximately 1,440 MBbls of our crude oil production and approximately 32.5 Bcf of our natural gas production. Currently, we do not hedge our NGL production.

Strategic acquisitions

We examine and evaluate acquisition opportunities as they present themselves and pursue those that meet our strategic plan and that we believe would increase shareholder value. We typically pursue the acquisition of assets with high quality undeveloped drilling locations, producing wells and/or behind-pipe reserves. We seek properties with large undeveloped drilling upside where we believe we can utilize our operational abilities to add shareholder value. In addition, we may pursue opportunities to swap acreage with other producers in order to optimize our portfolio by consolidating and concentrating our core assets. The large contiguous acreage blocks created through swapping of acreage provide the opportunity to optimize drilling activities and add more extended-reach lateral wells to our drilling program. We have an experienced team of management, engineering, geosciences and commercial professionals who identify and evaluate acquisition opportunities.

Selective exploration

In the current commodity pricing environment, we do not expect our exploration activity to be significant in 2016. 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. We have attempted 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 in the proximity of existing or emerging midstream infrastructure.

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

Our Oil and Gas Exploration and Production segment primarily reflects 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 to proved reserves 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 drilling of oil and gas wells, which are drilled, completed and put into production. Subsequent to completion, we operate and maintain the wells while controlling associated production costs. Upon extraction of the estimated recoverable reserves from a well, it is plugged and surface disturbance surrounding the well and producing facilities is remediated. In some cases, we may also own a working interest in wells operated by unrelated third-parties. The Oil and Gas Exploration and Production segment's most significant customers are currently Suncor Energy Marketing, Inc., Concord Energy, LLC, DCP Midstream, LP and Shell Trading Company. Sales to each of these parties constitute more than 10% of our revenues.

Our crude oil, natural gas and NGLs production is gathered, marketed and sold as follows:

- *Crude oil*. We do not refine any of our crude oil production. In the Wattenberg Field, crude oil is sold under various purchase contracts with monthly and longer term pricing provisions based on NYMEX pricing, adjusted for differentials. We have entered into longer term commitments ranging from three months to one year to deliver crude oil to competitive markets and these agreements have resulted in significantly improved deductions compared to earlier in 2015. 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 of production. We began delivering crude oil in accordance with our long term commitment to the White Cliffs Pipeline, LLC ("White Cliffs") pipeline in July 2015. This is one of several agreements we have entered into to facilitate deliveries of a portion of our crude oil to the Cushing, Oklahoma market. In addition, we have signed a long-term agreement for gathering of crude oil at the wellhead by pipeline from several of our pads in the Wattenberg Field, with a view toward minimizing truck traffic, increasing reliability and reducing the overall physical footprint of our well pads. We began delivering crude oil into this pipeline during the fourth quarter of 2015 and expect the system to be fully operational in the first quarter of 2016. 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.

- *Natural gas*. We primarily sell our natural gas to midstream service providers, marketers and utilities. Our natural gas is transported through third-party gathering systems and pipelines and we incur gathering, processing and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. We generally sell the natural gas that we produce in the Wattenberg Field under contracts with indexed, NYMEX or CIG monthly pricing provisions, with the remaining production sold under contracts with daily pricing provisions. Virtually all of our contracts include provisions whereby prices change with the market, with certain adjustments that may be made based on whether a well delivers to a gathering or transmission line and the quality of the natural gas. We have entered into firm gathering and processing agreements for all of our gas production to ensure there is infrastructure available to process the gas and get it to market. In the Wattenberg Field, the majority of our leasehold is dedicated to our primary midstream provider, DCP Midstream, LP, which gathers and processes wet natural gas produced in the basin and sells our residue gas to various markets. In the fourth quarter of 2014, we entered into an agreement with AKA Energy Group ("AKA") whereby we have committed production from a specified number of new horizontal wells to be drilled and completed by the end of 2016. Pursuant to the agreement, AKA is required to install and operate, or contract for use of, facilities necessary to receive and purchase the production volumes committed under the agreement. In the Utica Shale, wet natural gas produced in our northern acreage is gathered and processed pursuant to a firm gathering and processing agreement with MarkWest Utica EMG ("MarkWest") while wet natural gas produced in our southern acreage is gathered and processed by Blue Racer Midstream LLC ("Blue Racer"). The natural gas sales from the Blue Racer Plant are based on TETCO M-2 pricing. The gas sold at the tailgate of the MarkWest plant is sold at a price relative to the Chicago/Midwest market. Our sale of a significant portion of our Utica Shale gas to the Midwest market has helped to reduce the impact of the significant differentials that exist between the TETCO M-2 realizations and the NYMEX gas price. We anticipate that the significant Appalachian pipeline differentials that impact our Utica Shale natural gas, which make economics challenging, will continue well into 2016.

- *NGLs*. In the Wattenberg Field, all of our NGLs are sold at the tailgate of the third-party midstream service provider processing plants based on a combination of prices from the Conway hub in Kansas and Mt. Belvieu in Texas where this production is marketed. 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 under both short- and long-term contracts. Due to an oversupply and growing inventories of nearly all domestic NGLs products, our realized sales price for NGLs declined significantly during 2015 and, while these prices have stabilized, we expect pricing to remain at depressed levels well into 2016 and perhaps beyond.

Gas Marketing

Our Gas Marketing segment is comprised solely of the operating activities of our wholly-owned subsidiary RNG. RNG specializes in the purchase, aggregation and sale of natural gas production in the Appalachian Basin. Financial results from our gas marketing segment were not material to our consolidated financial statements for any of the periods presented in this report and we do not expect them to be material in the future. RNG purchases for resale natural gas produced by third-party producers. 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. As of December 31, 2015, the dollar commitment related to this long-term firm transportation, sales and processing agreement was approximately $20.6 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 continue to remain depressed, certain third-party producers under our Gas Marketing segment have begun and may continue to experience financial distress, which has led to certain contractual defaults and litigation. To date, we have had no material counterparty default losses; however, we expect continued deterioration in the financial position of some counterparties. In 2015, we recorded an allowance for doubtful accounts of approximately $0.5 million. We have initiated several legal actions for collection against some of the third-party producers, which have resulted in no collections and some of the third-party producers shutting-in wells. As a result, 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. Following the sale of our 50% ownership interest in PDCM in October 2014, RNG's marketing activities were scaled down and are focused on selling natural gas production to meet its volume commitments. After the long-term firm transportation agreements expire, we expect to discontinue this segment.

For additional information regarding our business segments, see Note 17, *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, 2015					
	Crude Oil		Natural Gas		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	625	380.9	2,329	2,102.9	2,954	2,483.8
Utica Shale	25	19.9	3	3.0	28	22.9
Total productive wells	650	400.8	2,332	2,105.9	2,982	2,506.7

Proved Reserves

The following table presents our proved reserve estimates as of December 31, 2015 based on a reserve report prepared by Ryder Scott and related information:

	Proved Reserves at December 31, 2015					
	Proved Reserves (MMBoe)	**% of Total Proved Reserves**	**% Proved Developed**	**% Liquids**	**Proved Reserves to Production Ratio (in years)**	**2015 Production (MBoe)**
Wattenberg Field	270	99%	25%	60%	18.9	14,232
Utica Shale	3	1%	100%	55%	2.8	1,138
Total proved reserves	273	100%	26%	60%	17.8	15,370

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. 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, 2015, all of our proved reserves, including our proportionate share of our affiliated partnerships' reserves, have been estimated by Ryder Scott.

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 and accounting personnel for adherence to SEC guidelines through a detailed review of land records, available geological and reservoir data, and production performance data. The process includes a review of applicable working and net revenue interests and cost and performance data. The internal team compiles the reviewed data and forwards the data to Ryder Scott.

When preparing our reserve estimates, Ryder Scott did not independently verify 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 prepares an estimate 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 report is reviewed by our engineering staff and management prior to issuance by Ryder Scott.

The professional qualifications of the internal lead engineer primarily responsible for overseeing the preparation of our reserve estimates qualify the engineer as a Reserves Estimator, 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. This person holds a Bachelor of Science degree in Petroleum and Chemical Refining Engineering with a minor in Petroleum Engineering, has over 39 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 actual production from projects in the same reservoir or an analogous reservoir or by other 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 2015 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.

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 unaudited *Supplemental Information - Crude Oil and Natural Gas Information* 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,		
	2015	2014	2013 (3)
Proved reserves			
Crude oil and condensate *(MMBbls)*	99	101	94
Natural gas *(Bcf)*	661	537	740
NGLs *(MMBbls)*	64	60	49
Total proved reserves *(MMBoe)*	273	250	266
Proved developed reserves *(MMBoe)*	70	75	76
Estimated future net cash flows *(in millions)* (1)	$ 2,259	$ 4,938	$ 4,323
PV-10 (*in millions)* (2)	$ 1,338	$ 3,450	$ 2,704
Standardized measure *(in millions)*	$ 1,097	$ 2,306	$ 1,782

(1) Amount represents undiscounted pre-tax future net cash flows estimated by Ryder Scott of approximately $2.8 billion, $7.3 billion and $6.4 billion as of December 31, 2015, 2014 and 2013, respectively, less an internally-estimated future income tax expense of approximately $0.5 billion, $2.3 billion and $2.1 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.

(3) Includes estimated reserve data related to our Marcellus Shale crude oil and natural gas properties, which were divested in October 2014. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of these assets.

The following table sets forth information regarding estimated proved reserves for our Marcellus Shale crude oil and natural gas properties:

		December 31, 2013
Proved reserves		
Natural gas *(Bcf)*		237
Total proved reserves *(MMBoe)*		40
Proved developed reserves (MMBoe)		9
Estimated future net cash flows *(in millions)*	$	394

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

	As of December 31, 2015				
Operating Region/Area	Crude Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Crude Oil Equivalent (MBoe)	Percent
Proved developed					
Wattenberg Field	25,240	166,679	14,284	67,304	95%
Utica Shale	1,017	8,688	727	3,192	5%
Total proved developed	26,257	175,367	15,011	70,496	100%
Proved undeveloped					
Wattenberg Field	72,718	485,370	48,716	202,329	100%
Utica Shale	—	—	—	—	—%
Total proved undeveloped	72,718	485,370	48,716	202,329	100%
Proved reserves					
Wattenberg Field	97,958	652,049	63,000	269,633	99%
Utica Shale	1,017	8,688	727	3,192	1%
Total proved reserves	98,975	660,737	63,727	272,825	100%

We have stress-tested our proved reserve estimates as of December 31, 2015 to determine the impact of lower crude oil prices. Replacing the 2015 NYMEX commodity prices used in estimating our reported proved reserves (see *Supplemental Information - Crude Oil and Natural Gas Information,* provided with our consolidated financial statements included elsewhere in this report) with those shown on the table below, and leaving all other parameters unchanged, results in a decrease in 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, 2015 Estimated Reserves**
2015 Reserve Report (2)	$ 50.28	$ 2.59	272.8	—
Scenario A	40.00	2.59	266.1	(2)%
Scenario B	30.00	2.59	256.5	(6)%

(1) These prices are indices and do not include basin differentials for crude oil and natural gas. The above scenarios were calculated using the indicated index prices, less any basin differentials, transport fees, contractual adjustments and any Btu adjustments we experienced for the respective commodity.

(2) The NYMEX prices used for the 2015 Reserve Report are based on SEC price parameters using the unweighted average of the prices in effect on the first day of the month for each month within the period of January 2015 through December 2015.

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage:

	As of December 31, 2015					
	Developed		Undeveloped		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	97,600	89,400	7,600	6,300	105,200	95,700
Utica Shale	3,166	2,670	66,132	62,044	69,298	64,714
Total acreage	100,766	92,070	73,732	68,344	174,498	160,414

Substantially all of our undeveloped acreage in the Wattenberg Field is related to leaseholds that are held-by-production. Approximately 8%, 21% and 7% of our undeveloped leaseholds in the Utica Shale are scheduled to expire during 2016, 2017 and 2018, respectively. While the undeveloped leaseholds expiring in 2016 in the Utica Shale are not significant, we believe that our planned modest investment in the Utica Shale in 2016 will provide production, reservoir and completion analyses that will provide us with a better understanding of our Utica Shale acreage as we exit 2016 and may influence our re-leasing decisions as more undeveloped leaseholds expire in 2017. In the event these leaseholds are not renewed, we do not expect a significant charge as the carrying value of our Utica Shale acreage as of December 31, 2015 is not material as a result of impairments recorded in 2014 and 2015.

Drilling Activity

The following table presents information regarding the number of wells drilled or participated in for the period presented. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

	Year Ended December 31,					
	2015		2014		2013	
Operating Region	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field, operated wells	140	113.5	88	71.0	62	53.3
Wattenberg Field, non-operated wells	58	9.3	70	14.9	35	7.9
Utica Shale	4	3.0	9	8.0	11	8.7
Other (1)	—	—	4	2.0	10	5.0
Total wells drilled	202	125.8	171	95.9	118	74.9

(1) Includes drilling activity in the Marcellus Shale crude oil and natural gas properties, which were divested in October 2014.

The following tables set forth 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 spud, turned-in-line and producing during the period. 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.

	Net Development Well Drilling Activity								
	Year Ended December 31,								
	2015			2014			2013		
Operating Region/Area	Productive	In-Process	Dry (1)	Productive	In-Process	Dry (1)	Productive	In-Process	Dry
Wattenberg Field, operated wells	110.8	50.6	2.7	75.8	36.5	1.7	40.5	—	—
Wattenberg Field, non-operated wells	9.3	4.6	—	14.9	6.3	—	13.0	15.6	0.1
Utica Shale	3.0	4.2	—	7.0	3.0	1.0	3.0	2.0	—
Other (2)	—	—	—	2.0	—	—	3.5	2.0	—
Total net development wells	123.1	59.4	2.7	99.7	45.8	2.7	60.0	19.6	0.1

(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.

We had no exploratory well drilling activity in 2015 and 2014. The following table presents our net exploratory well drilling activity in 2013:

	Net Exploratory Well Drilling Activity December 31, 2013		
Operating Region/Area	Productive	In-Process	Dry
Utica Shale	4.2	—	—
Other (1)	1.5	—	—
Total net exploratory wells	5.7	—	—

____

(1) 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 with respect to discovered defects which we deem to be significant. 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 Note 8, *Long-Term Debt*, to our consolidated financial statements included elsewhere in this report.

Facilities

We lease 56,000 square feet of office space in Denver, Colorado, which serves as our corporate office, through February 2021. We own a 32,000 square foot administrative office building located in Bridgeport, West Virginia and a newly acquired 60,000 square foot field operating facility in Greeley, Colorado.

We own or lease field operating facilities in Evans, Colorado 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 2014, Colorado Governor Hickenlooper created a task force charged with crafting recommendations to help minimize land use conflicts relating to the location of oil and gas facilities. The task force was created pursuant to a compromise under which certain potential ballot initiatives that would have impacted the oil and natural gas industry in Colorado were withdrawn from the November 2014 ballot. The task force, which was called the Task Force on State and Local Regulation of Oil and Gas Operations, was comprised of 21 members representing various interests. Recommendations of the task force regarding new or amended legislation, appropriations or other action were submitted to the Governor in February 2015. In 2015 and into 2016, the Colorado Oil and Gas Conservation Commission (the "COGCC") conducted a rulemaking to implement two of these task force recommendations related to the permitting of large-scale facilities in urban mitigation areas and municipality notice provisions. Both rulemakings were finalized in January 2016 and new rules will become effective in spring 2016. In addition, depending on the outcome of the task force process and any related legislative or administrative activity, ballot initiatives, like those proposed in December 2015 and again in January 2016, affecting our operations may be proposed and adopted by the voters in future elections.

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% of the leases located within the proposed unit. State laws may establish maximum rates of production from crude oil and natural gas wells, 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. 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.

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 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 continues its study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and issued a draft assessment in June 2015, with a final, peer-reviewed report expected in 2016. 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 and Ohio, have adopted regulations regarding permitting, transparency and well construction requirements with respect to hydraulic fracturing operations and may in the future adopt additional regulations or otherwise seek to ban fracturing activities altogether. Colorado requires 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 COGCC issued new, more restrictive rules regarding spill reporting and remediation. See further discussion in Item 1A, *Risk Factors*.

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, which are anticipated to be effective in March 2016, 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 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. These rules are not yet final and we do not have an anticipated effective date. Additionally, in November 2015, the ODNR Assistant Chief announced draft rules in progress include 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, local governing bodies have begun to issue 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 cities of Boulder, Lafayette, Fort Collins and Brighton passed hydraulic fracturing bans. See Item 1A, *Risk Factors*, for a more detailed discussion of these bans. 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) or remediate property contamination (including surface and groundwater contamination) or to 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 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 the development of regulations to implement these requirements. We may be required to incur certain capital expenditures 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 ("NSPS OOOO") became effective in 2012, with more amendments effective in 2013 and 2014, all of which have added administrative and operational costs. In addition, as part of its comprehensive strategy to further reduce methane emissions from the oil and gas sector, EPA proposed amendments to NSPS OOOO in 2015 that would impose additional control and other requirements to reduce such emissions. A final rule is expected in the summer of 2016. 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 more stringent than NSPS OOOO 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 strengthened 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 and Ohio. By October 2016, states are expected to have revised state implementation plans and proposed regulations to meet the new standard.

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 loadout 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 defining 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 May 2014 proposed a rule to alter how it identifies critical habitat for endangered and threatened species. It is unclear when this rule will be finalized.

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. Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil, including us, to procure and implement additional SPCC measures relating to the possible discharge of crude oil into surface waters. 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 2016 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 Note 12, *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 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 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 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. 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, 2015, we had 362 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, shareholder 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 continuing 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 fallen dramatically since mid-2014, with a high over $100 per barrel in June 2014 to recent lows below $30 per barrel, in each case based on WTI prices, due to a combination of factors including increased U.S. supply, global economic concerns, the likely resumption of oil exports from Iran and OPEC's decision not to reduce supply. Prices for natural gas and NGLs have experienced declines of similar magnitude. These declines have adversely affected, among other things, our revenue and reserves, and has caused us to reduce our company-wide budgeted 2016 capital program relative to 2015 and 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. An extended period of continued lower oil prices, or additional price declines, will have further adverse effects on us. For example, if we reduce our capital expenditures further 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.

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.

Our operations are focused primarily on the Wattenberg Field, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Approximately $400 million, or 91%, of our 2016 capital forecast is expected to be spent on development activities in the Wattenberg Field. Because our operations are 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 the area 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 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, 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.

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 Safe Drinking Water Act ("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 concludes 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. EPA's science advisory board, however, has subsequently questioned several elements and conclusions in EPA's draft assessment. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

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. 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, 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. 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.

EPA also finalized major new U.S. Clean Air Act ("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, 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 September 2015 EPA published proposed amendments to the 2012 NSPS Quad OOOO rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The proposed rule would include, among others, 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. If finalized, these additional methane reduction requirements could increase future costs of our operations and require us to make modifications to our operations and install new equipment. These CAA rules and associated amendments are substantial and will increase future costs of our operations and will require us to make modifications to our operations and install new equipment.

On the same day EPA proposed amendments to NSPS Quad OOOO, EPA also published a proposed rule regarding source determination and permitting requirements for the onshore oil and gas industry under the CAA. The proposed rule sought public comment on two approaches for defining 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. Depending on EPA's final approach, the oil and gas industry and our operations could be subject to increased permitting costs and more stringent control requirements.

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 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 January 2016, BLM proposed rules to further regulate venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. The rules, which would require additional controls and impose new emissions and other standards on certain operations on applicable leases, are expected to be finalized in 2016. 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. The public comment period for this proposal closed January 8, 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 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. New York has also placed a permanent moratorium on all hydraulic fracturing activities within the state. Similar initiatives could spread to 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 heard oral arguments on December 9, 2015, and a decision is expected in the first half of 2016. If the Colorado Supreme Court determines the bans are valid, such a decision could increase the costs of our operations, impact our profitability, and prevent us from drilling in certain locations. 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.

Ballot initiatives have been proposed in Colorado 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. This could adversely affect the cost, manner, and feasibility of development activities in Colorado or elsewhere, particularly those involving hydraulic fracturing, and significantly affect the value of our assets and our financial results and impede our growth.

Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various options for ballot initiatives aimed at significantly limiting or preventing oil and natural gas development. Signatures for two such proposals were submitted for a vote at the November 2014 election. One proposed to amend the Colorado constitution to establish an "environmental bill of rights" that would have allowed local governments in Colorado the right, without limitation, to prohibit crude oil and natural gas development within their respective jurisdictions. The second proposal would have imposed a statewide mandatory minimum spacing, or setback, between oil and gas wells and occupied structures of 2,000 feet. As part of a compromise negotiated by Governor John Hickenlooper, both initiatives were withdrawn prior to the election and were not voted upon. In December 2015, interest groups filed a package of 11 potential ballot initiatives focused on restricting oil and gas development in Colorado. Among other things, these initiatives, if successful, could require mandatory setbacks, allow local control over drilling, and impose prohibitions on drilling. Additional proposals of this nature may be made in the future, including in other states. Should any such proposal be successful and survive legal challenge, it could have a materially adverse impact on our ability to drill and/or produce crude oil and natural gas in Colorado or elsewhere, and could materially impact our results of operations, production and reserves.

Moreover, pursuant to the compromise that resulted in the withdrawal of the 2014 ballot proposals, in February 2015, a task force created by the State of Colorado made recommendations for minimizing land use and other conflicts concerning the location of new oil and gas facilities. The task force ultimately approved and sent to Governor Hickenlooper for his review nine proposals. Three of the proposals required further legislative action, while the other six proposals required rulemaking or other regulatory action. The proposals contemplated (i) a senate bill that would postpone expiration of recently adopted regulations regarding air emissions; (ii) tasking the COGCC with crafting new rules related to siting of "large-scale" pads and facilities; (iii) requiring the industry to provide advance information about development plans to local governments; (iv) improving the COGCC's local government liaison and designee programs; (v) adding 11 full-time staffers to the COGCC to improve inspections and field operations; (vi) bolstering the inspection staff and equipment for monitoring oil and gas facility air emissions and setting up a hotline for citizen health complaints at the Colorado Department of Public Health and Environment; (vii) creating a statewide oil and gas information clearinghouse; (viii) studying ways to ameliorate the impact of oil and gas truck traffic and (ix) creating a compliance-assistance program at the COGCC to help operators comply with the state's changing rules and ensure consistent enforcement of rules by state inspectors. A number of additional proposals did not receive sufficient task force support to be included with the nine proposals, but may nevertheless result in future legislation or rulemakings.

In 2015 and into 2016, COGCC began a rulemaking to implement two of these recommendations (in particular items (ii) and (iii) identified above). With respect to recommendation (ii) above, the COGCC has finalized rules to permit "large-scale facilities" in "urban mitigation areas." With respect to recommendation (iii) above, the COGCC finalized rules requiring operators to provide certain municipalities with public notice prior to engaging in operations. Both rules will become effective later in 2016. These rulemakings could impact our ability to develop and operate in certain areas in Colorado. The other seven recommendations, which were ministerial in nature and did not require a separate rulemaking, have been or are being implemented.

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 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. Similar events could occur in the future. We are also dependent on the availability and capacity of crude oil purchasers for our production. For example, reductions in purchases by a local crude oil refinery beginning in late 2013 increased the amount of oil that we had to transport out of the Wattenberg area for sale. This increased our transportation costs and reduced the price we received for the affected production for much of 2014. We expect this situation could occur again in the future. In addition, the use of alternative forms of transportation such as trucks or rail involve risks, including the risk that increased regulation could lead to increased costs or shortages of trucks or railcars. We face similar risks in our Utica operating area. 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. Falling commodity prices have resulted in reduced investment in midstream facilities by some third parties, increasing the risk that sufficient midstream infrastructure will not be available in future periods.

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. Nevertheless, a vulnerability in the cyber security 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. Well publicized recent cyber-attacks include those directed at the U.S. Government’s Federal Office of Personnel Management, Anthem, Inc. and Sony Pictures, but lower profile attacks are also common.

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.

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.

In August 2015, we received a Clean Air Act Section 114 Information Request (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, 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 and will result in a state rulemaking to address the new “moderate” status. This rulemaking may result in more stringent standards or additional control requirements applicable to our operations in Colorado.

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 is expected to be finalized in 2016 and 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 could prevent us from drilling wells on certain locations we plan to develop, thereby reducing our reserves as well as our future revenues. In 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 January 2015, the COGCC amended its regulations to implement this new legislation. These legislative and regulatory amendments expand the COGCC's enforcement authority and tools by, for example, mandating monetary penalties for certain types of violations, requiring a penalty to be assessed for each day of violation, and significantly increasing the maximum daily penalty amount. These changes could significantly increase both the frequency and the amount of future administrative penalties assessed by the COGCC.

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 in the absence of comparable federal regulation is a significant new authority being asserted at the state level and has the potential to adversely affect operations in Colorado as well as in other parts of the country. In 2015, EPA proposed similar "methane" amendments to Subpart OOOO, which if finalized, could impose additional control or other regulatory requirements on our operations. 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 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.

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.

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, Colorado has a relatively arid climate and experiences 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 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 Resource Conservation and Recovery Act. EPA has not yet acted on the petition and it remains pending. Were EPA to begin treating some or all of these wastes as "hazardous" under

Subtitle C in response to the petition, 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 U.S. Clean Water Act ("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, 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 April 2015, EPA published proposed pretreatment standards for the oil and gas extraction industry. The proposed regulations would address discharges of 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, following the conclusion and finalization of EPA's study, the agency 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. These water-related concerns are heightened by the potential for flooding events in Colorado such as those that occurred in 2013. For example, during that flood we experienced damage to some of our facilities as well as other operational impediments.

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 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. In December 2012, we recognized an impairment charge of $161.2 million associated with our Piceance Basin proved crude oil and natural gas properties. In 2013, we recognized additional charges of $48.8 million associated with our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties. In December 2014, we recognized a charge of $158.3 million associated with our Utica Shale properties, and we recognized an additional charge of $150.3 million with respect to those properties in the third quarter of 2015. 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 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 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 utilize 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 has an even more limited history, particularly in the southern part of the play where most of our acreage is located. 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, 2015, approximately 74% 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 $2.0 billion during the five years ending December 31, 2020. 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. In December 2015, we received a comment letter from the staff of the SEC requesting certain information regarding our PUD disclosures in prior years, and we cannot predict the outcome of the comment process.

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. Because market prices for crude oil at the end of 2015 were significantly lower than the average price for the year determined under SEC rules, the estimated quantity and present values of our reserves presented in this report using SEC pricing are higher than they would be if we had used year-end commodity prices instead.

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% 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. As we continue to develop our position in the Wattenberg Field, and as the field in general matures as a horizontal drilling play, it will be increasingly important for us to develop or acquire additional drilling opportunities there or elsewhere to replace our reserves as they are developed.

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. We reduced our forecasted company-wide capital expenditures in 2016 relative to 2015 in response to significant declines in the market price of crude oil, and we expect to drill fewer wells during the year. 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. If these 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.

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. Recent reductions in drilling and completion costs, which have accompanied lower commodity prices, may not be continued or sustained. If we drill a dry hole or unprofitable well on a current or future prospect, the profitability of our operations will decline and the value of our properties will likely be reduced. These risks are greater in developing areas such as the Utica Shale. 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. Historically, 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. 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.

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 believe the current market environment for some types of financing, including high-yield notes, to be highly adverse. In addition, 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 indenture 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 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. Significant recent decreases in the price of crude oil are likely 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 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. If our operating performance declines, we may in the future need to seek to obtain 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 2016. 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 87% 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 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 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 derivative contract defaults on its contractual obligations. Based on current commodity prices and our current derivative position, we may receive significant revenues from our derivative positions in 2016, increasing the adverse consequences to us if a derivative counterparty fails to perform. In addition, many of our 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, 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, 2015, we had hedged a total of 5.6 million barrels of oil volumes and 77,320 BBtu of natural gas hedged for 2016, 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. To the extent that oil and natural gas prices remain at current levels or decline further, we will not be able to hedge future production at the same pricing level as our current hedges and this could negatively impact our results of operations and financial condition.

Since we do not designate our derivatives as hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of derivatives are recorded in our income statements, and our net income is subject to greater volatility than it would be if our 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 derivatives as well as the 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% 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 swaps 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. In the current commodity price environment, 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 swaps 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 swap or exchange. Such an undervaluation would result in the transaction being less favorable to us than we expected.

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.

The administration of U.S. President Barack Obama has proposed to eliminate certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The proposals 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. In addition, the President has recently proposed a $10.25 per barrel tax on oil companies. 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, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). 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, or will be, subject to significant new capital, margin and business conduct 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.

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, 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 EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings provide the basis for EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the U.S. Clean Air Act ("CAA"). In June 2010, 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, EPA recommended options for BACT from the largest sources, which include improved energy efficiency, among others. 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 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 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 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. EPA intends to conduct future rulemaking to make appropriate revisions in light of the court rulings. Depending on what EPA does, 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 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. Following the publication in March 2014 of a series of Methane White Papers addressing suspected methane emissions from the oil and gas sector, EPA proposed new rules in 2015 aimed at further reducing methane emissions from the oil and gas sector, with final rules expected in 2016. These rules, which build on the Methane White Papers, include new regulatory requirements affecting our operations. In addition, a lawsuit has been filed by several northeastern states that would require 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% 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.

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, as discussed above, in August 2015 we received a Clean Air Act Section 114 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.

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. 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.

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 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

On December 21, 2015, we received a comment letter from the staff of the Division of Corporation Finance of the SEC (the "Staff"). The comments from the Staff were issued with respect to its review of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. We responded to all of the Staff's comments in a letter we filed with the SEC dated January 29, 2016. Included in our response were the supplemental analyses and information requested by the Staff. On February 18, 2016, we received a follow-up comment letter from the Staff, which we are currently reviewing. As of the date of the filing of this Annual Report on Form 10-K, we are continuing to work with the Staff on our responses and, therefore, these comments remain unresolved.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 12, *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 for each of the periods presented:

	High	Low
January 1 - March 31, 2014	$ 64.27	$ 44.72
April 1 - June 30, 2014	70.44	56.88
July 1 - September 30, 2014	63.73	49.82
October 1 - December 31, 2014	50.95	27.91
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

As of February 1, 2016, we had approximately 650 shareholders 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 and the indenture governing our 7.75% senior notes due 2022 and we presently intend to continue a policy of using retained earnings for expansion of our business. See Note 8, *Long-term Debt*, to our consolidated financial statements included elsewhere in this report.

The following table presents information about our purchases of our common stock during the three months ended December 31, 2015:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 - 31, 2015	3,190	$ 54.76
November 1 - 30, 2015	3,598	61.19
December 1 - 31, 2015	20,178	53.78
Total fourth quarter purchases	26,966	54.89

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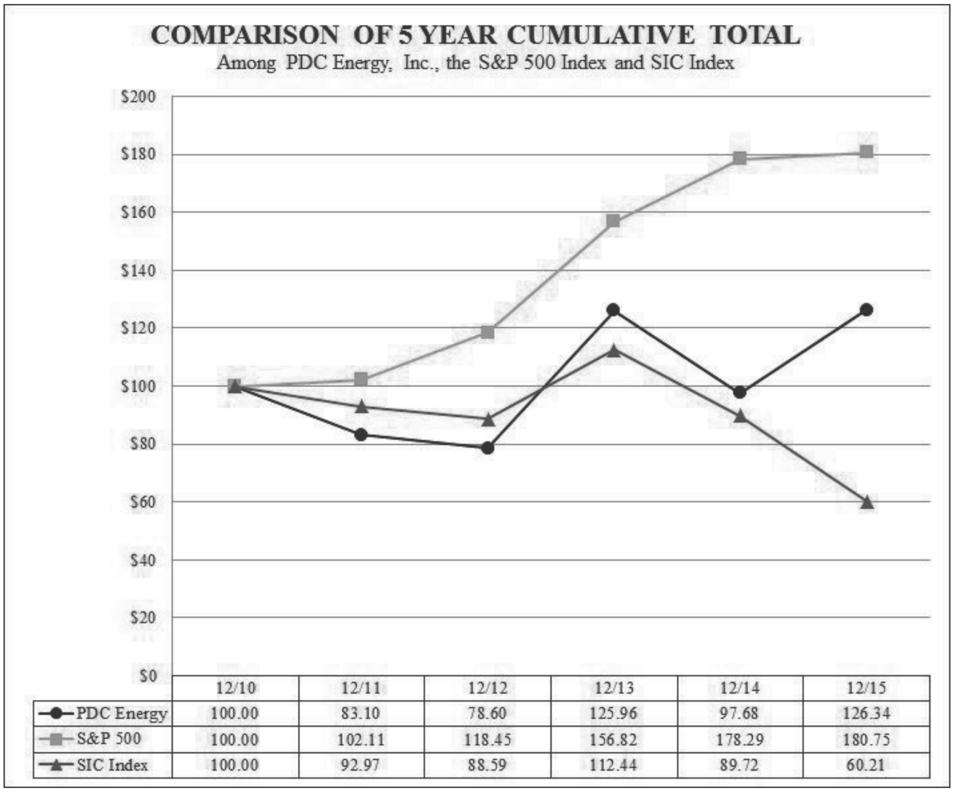
(1) *Purchases primarily represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.*

SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2015, 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 235 crude petroleum and natural gas companies. The cumulative total shareholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2010 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.



	12/10	12/11	12/12	12/13	12/14	12/15
PDC Energy	100.00	83.10	78.60	125.96	97.68	126.34
S&P 500	100.00	102.11	118.45	156.82	178.29	180.75
SIC Index	100.00	92.97	88.59	112.44	89.72	60.21

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended/As of December 31,				
	2015	2014	2013	2012	2011
	(in millions, except per share data and as noted)				
Statement of Operations (From Continuing Operations):					
Crude oil, natural gas and NGLs sales	$ 378.7	$ 471.4	$ 340.8	$ 228.0	$ 216.1
Commodity price risk management gain (loss), net	203.2	$ 310.3	(23.9)	29.3	39.4
Total revenues	595.3	856.2	392.7	307.1	323.3
Income (loss) from continuing operations	(68.3)	107.3	(21.1)	(19.4)	23.2
Earnings per share from continuing operations:					
Basic	$ (1.74)	$ 3.00	$ (0.65)	$ (0.70)	$ 0.98
Diluted	(1.74)	2.93	(0.65)	(0.70)	0.97
Statement of Cash Flows:					
Net cash from:					
Operating activities	$ 411.1	$ 236.7	$ 159.2	$ 174.7	$ 166.8
Investing activities	(604.3)	(474.1)	(217.1)	(451.9)	(456.4)
Financing activities	178.0	60.3	248.7	271.4	243.4
Capital expenditures	604.7	628.6	394.9	347.7	334.5
Acquisitions of crude oil and natural gas properties	—	—	9.7	312.2	145.9
Balance Sheet:					
Total assets	$ 2,370.5	$ 2,331.1	$ 1,991.7	$ 1,777.9	$ 1,676.1
Working capital	30.7	89.5	90.0	(67.6)	(38.1)
Total debt, net of unamortized discount and debt issuance costs	642.4	655.5	593.9	637.5	502.4
Total equity	1,287.2	1,137.4	967.6	703.2	664.1
Pricing and Lease Operating Expenses From Continuing Operations (per Boe):					
Average sales price (excluding net settlements on derivatives)	$ 24.64	$ 50.72	$ 52.23	$ 46.85	$ 49.97
Average lease operating expenses	3.71	4.56	5.18	5.54	4.95
Production (MBoe):					
Production from continuing operations	15,369.4	9,294.4	6,524.7	4,866.5	4,324.4
Production from discontinued operations	—	1,093.0	2,032.6	3,458.7	3,596.3
Total production	15,369.4	10,387.4	8,557.3	8,325.2	7,920.7
Total proved reserves (MMBoe) (1)(2)(3)	272.8	250.1	265.8	192.8	169.3

(1) *Includes total proved reserves related to our Marcellus Shale and shallow Upper Devonian Appalachian Basin assets of 40 MMBoe, 30 MMBoe and 22 MMBoe as of December 31, 2013, 2012 and 2011, respectively. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Marcellus Shale and shallow Upper Devonian Appalachian Basin assets.*

(2) *Includes total proved reserves related to our Piceance Basin and North Eastern Colorado ("NECO") assets of 14 MMBoe and 59 MMBoe as of December 31, 2012 and 2011, respectively. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Piceance Basin and NECO assets.*

(3) *Includes total proved reserves related to our Permian Basin assets of 11 MMBoe as of December 31, 2011. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Permian Basin assets.*

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.

EXECUTIVE SUMMARY

2015 Financial Overview

Production volumes from continuing operations increased substantially to 15.4 MMboe in 2015 compared to 9.3 MMboe in 2014, representing an increase of 65%. The increase in production volumes was primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Crude oil production from continuing operations increased 62% in 2015, while NGL production from continuing operations increased 61%. Crude oil production comprised approximately 45% of total production from continuing operations in 2015. Natural gas production from continuing operations increased 73% in 2015 compared to 2014 as we shifted our 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. For the month ended December 31, 2015, we maintained an average production rate of 52 MBoe per day, up from 30 MBoe per day for the month ended December 31, 2014.

Crude oil, natural gas and NGLs sales from continuing operations, coupled with the impact of settlement of derivatives, increased in 2015. Increased production and positive net settlements on derivative positions more than offset the effect of declines in commodity prices during the year. Lower crude oil and natural gas index prices in 2015 were the primary reason for significant positive net settlements of $238.9 million on derivative positions compared to negative net settlements of $0.8 million in 2014. Crude oil, natural gas and NGLs sales, including the impact of net settlements on derivatives, was $617.6 million in 2015 compared to $470.6 million in 2014. This represents an increase of 31% in 2015 compared to 2014.

Other significant changes impacting our 2015 results of operations include the following:

- Crude oil, natural gas and NGLs sales decreased to $378.7 million in 2015 compared to $471.4 million in 2014, due to a 51% decrease in the weighted-average realized prices of crude oil, natural gas and NGLs, offset in part by a 65% increase in production;
- Negative net change in the fair value of unsettled derivative positions in 2015 was $35.8 million compared to a positive net change in the fair value of unsettled derivative positions of $311.1 million in 2014, primarily attributable to crude oil and natural gas derivatives that settled in 2015;
- General and administrative expense decreased to $90.0 million in 2015 compared to $123.6 million in 2014, 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;
- Impairment of crude oil and natural gas properties was $161.6 million in 2015 compared to $166.8 million in 2014, both primarily related to the write-down of our Utica Shale producing and non-producing crude oil and natural gas properties; and
- Depreciation, depletion and amortization expense increased to $303.3 million in 2015 compared to $192.5 million in 2014, primarily due to increased production, offset in part by lower weighted-average depreciation, depletion and amortization rates.

Available liquidity as of December 31, 2015 was $402.2 million compared to $398.4 million as of December 31, 2014. Available liquidity as of December 31, 2015 is comprised of $0.9 million of cash and cash equivalents and $401.3 million available for borrowing under our revolving credit facility. These amounts exclude an additional $250 million available under our revolving credit facility, subject to certain terms and conditions of the agreement. In September 2015, we completed the semi-annual redetermination of the borrowing base under our revolving credit facility, which resulted in the reaffirmation of the borrowing base at $700 million. We have elected to maintain the aggregate commitment level at $450 million.

In March 2015, we completed a public offering of 4,002,000 shares of our common stock for net proceeds of approximately $203 million, after deducting offering expenses and underwriting discounts. We used a portion of the proceeds of the offering to repay all amounts then outstanding on our revolving credit facility, and used the remaining amounts to fund a portion of our capital program. With our current derivative position, available liquidity and expected cash flows from operations, we believe we have sufficient liquidity to allow us to execute our expected capital program through 2016.

2015 Operational Overview

During 2015, we continued to execute our strategic plan of increasing production, reserves and cash flows from drilling operations in the Wattenberg Field in Colorado and from completion activities in the Utica Shale play in southeastern Ohio. In the Wattenberg Field, we reduced our rig count in December to four automated drilling rigs from five due to the increases in our drilling rig efficiencies. In 2015, we spud 174 horizontal wells in the Wattenberg Field and turned-in-line 136 horizontal wells. We also participated in 54 gross, 8.1 net, horizontal non-operated wells that were spud and 58 gross, 9.3 net, horizontal non-operated wells which were turned-in-line. We began implementing several horizontal well-recovery enhancements in 2015, including tighter spacing between frac intervals on all wells and by drilling 40% of our wells with extended reach laterals of 6,500 feet to 7,000 feet. We have been able to improve our drilling time due to several factors, including the use of automated drilling rigs that minimize downtime, improved drilling team cohesion and utilizing analytics to improve drilling efficiencies. In the Utica Shale, we completed and turned-in-line a four-well pad during the first half of 2015. As a result of the turn-in-line of a four-well pad in late 2014 and a four-well pad in the second quarter of 2015, production volumes from the Utica Shale increased 41% in 2015 compared to 2014.

2016 Operational Outlook

We expect our production for 2016 to range between 20.0 MMBoe to 22.0 MMBoe and that our production rate will average approximately 55,000 to 60,000 Boe per day. Our 2016 capital forecast of approximately $435 million at the midpoint is focused on continuing to provide value-driven production growth by exploiting our extensive inventory of reasonable rate-of-return projects in the Wattenberg Field. Capital spending is expected to be weighted to the front half of 2016 as we complete Wattenberg Field in-process wells spud in 2015 and execute our Utica Shale drilling program.

Wattenberg Field. The 2016 capital forecast anticipates a four-rig drilling program in the Wattenberg Field based on our December 2015 outlook for future commodity prices. Approximately $400 million of our 2016 capital forecast is expected to be spent on development activities in the Wattenberg Field, comprised of approximately $350 million for our operated drilling program and approximately $35 million for non-operated projects. The remainder of the Wattenberg Field capital forecast is expected to be used for leasing, workover projects and other capital improvements, including the remodeling of our Greeley, Colorado, field operating facilities. We plan to spud 135 and turn-in-line 160 horizontal Niobrara or Codell wells and participate in approximately 35.0 gross, 7.0 net, non-operated horizontal opportunities in 2016.

Utica Shale. Based on the production results from recently drilled wells and decreases in well costs, in 2016 we plan on executing a modest drilling operation in the condensate and wet natural gas window of the play. Early in 2016, we plan to spend approximately $35 million in the Utica Shale to drill, complete and turn-in-line five wells, all of which are at least 6,000 foot laterals. The planned activity will focus on further delineation of our southern acreage, determining the impact of well-orientation on productivity and testing improved capital efficiency of a 10,000 foot lateral well.

2016 Operational Flexibility

In December 2015, the Board of Directors approved our 2016 development plan as described above. This plan, which primarily focuses on a four-rig drilling program in the Wattenberg Field, was based upon our December 2015 internal outlook for crude oil and natural gas prices, favorable debt metrics and the strength of our balance sheet, including our strong hedge position for 2016. In 2016, our goal continues to be preserving this balance sheet strength by managing our capital spending to approximate our cash flows from operations.

Since approving our 2016 development plan in December 2015, future commodity prices have continued to decline. Concurrently, capital costs to drill and complete Wattenberg Field wells have decreased, while crude oil differentials in the field have improved. We expect that our capital forecast of $420 million to $450 million will fund the same level of drilling and completions activity as projected prior to the aforementioned changes. Moreover, despite commodity prices decreasing in early 2016, we are anticipating reasonable rates of return in our middle core acreage in the Wattenberg Field.

The Company maintains significant operational flexibility in 2016 to reduce the pace of our capital spending. We will continue to monitor future commodity prices throughout 2016, and should prices remain depressed or continue to further deteriorate, we believe an adjustment to our development plan would be appropriate. We have ample opportunities to reduce capital spending, including but not limited to: working with our vendors to achieve further cost reductions; reducing the number of rigs being utilized in our drilling program; and/or managing our completion schedule. The production impact of reduced 2016 capital spending would be felt primarily in 2017 and thereafter, as our anticipated long-term production growth would likely be reduced. This operational flexibility is maintained with little exposure to incurring additional costs, given that all of our acreage in the Wattenberg Field is held by production, a reduction in rigs would not cause us to incur substantial idling costs as our rig commitments are short term (30 to 90 days), and we do not anticipate having additional material unfulfilled transportation commitment fees. Further, throughout 2016, such a reduction would be consistent with maintaining compliance well within the limits of our debt covenants.

As we go through 2016, our priority remains ensuring ample liquidity and protecting the strength of our balance sheet, and we will adjust our development plans as necessary to this end. We remain in close contact with the banks in our credit facility and are evaluating the increased risk that lenders may seek to reduce our borrowing base due to regulatory pressure to reduce their exposure to the energy industry or for other reasons. Further, we continue to monitor debt, equity and hedging markets for opportunities to strengthen our liquidity position.

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	
	2015	2014	2013	2015-2014	2014-2013
	(dollars in millions, except per unit data)				
Production (1)					
Crude oil (MBbls)	6,983.8	4,321.9	2,909.7	61.6 %	48.5 %
Natural gas (MMcf)	33,301.7	19,298.0	15,431.2	72.6 %	25.1 %
NGLs (MBbls)	2,835.3	1,756.2	1,043.2	61.4 %	68.3 %
Crude oil equivalent (MBoe) (2)	15,369.4	9,294.4	6,524.7	65.4 %	42.4 %
Average MBoe per day	42.1	25.5	17.9	65.4 %	42.4 %
Crude Oil, Natural Gas and NGLs Sales					
Crude oil	$ 280.3	$ 348.6	$ 261.6	(19.6)%	33.3 %
Natural gas	68.0	74.7	50.0	(9.0)%	49.4 %
NGLs	30.4	48.1	29.2	(36.8)%	64.7 %
Total crude oil, natural gas and NGLs sales	$ 378.7	$ 471.4	$ 340.8	(19.7)%	38.3 %
Net Settlements on Derivatives (3)					
Natural gas	$ 30.0	$ (3.1)	$ 14.3	*	*
Crude oil	208.9	2.3	(3.1)	*	*
Total net settlements on derivatives	$ 238.9	$ (0.8)	$ 11.2	*	*
Average Sales Price (excluding net settlements on derivatives)					
Crude oil (per Bbl)	$ 40.14	$ 80.67	$ 89.92	(50.2)%	(10.3)%
Natural gas (per Mcf)	2.04	3.87	3.24	(47.3)%	19.4 %
NGLs (per Bbl)	10.72	27.39	27.97	(60.9)%	(2.1)%
Crude oil equivalent (per Boe)	24.64	50.72	52.23	(51.4)%	(2.9)%
Average Lease Operating Expenses (per Boe) (4)					
Wattenberg Field	$ 3.78	$ 4.82	$ 4.68	(21.6)%	3.0 %
Utica Shale	2.79	1.87	2.63	49.2 %	(28.9)%
Other	—	3.19	14.81	*	(78.5)%
Weighted-average	3.71	4.56	5.18	(18.6)%	(12.0)%
Natural Gas Marketing Contribution Margin (5)	$ (0.8)	$ (0.4)	$ (0.3)	(100.0)%	(33.3)%
Other Costs and Expenses					
Production taxes	$ 18.4	$ 25.6	$ 21.8	(28.0)%	17.7 %
Transportation, gathering and processing expenses	10.2	4.6	5.2	121.1 %	(10.9)%
Exploration expense	1.1	0.9	6.3	16.4 %	(85.0)%
Impairment of crude oil and natural gas properties	161.6	166.8	52.9	(3.1)%	215.6 %
General and administrative expense	90.0	123.6	63.7	(27.2)%	93.9 %
Depreciation, depletion and amortization	303.3	192.5	115.6	57.5 %	66.5 %
Interest expense	$ 47.6	$ 47.8	$ 50.1	(0.6)%	(4.6)%

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

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by our ownership percentage. For total production volume, including discontinued operations, see Part I, Item 6, Selected Financial Data.
(2) One Bbl of crude oil or NGL equals six Mcf of natural gas.
(3) Represents net settlements on derivatives related to crude oil and natural gas sales, which do not include net settlements on derivatives related to natural gas marketing.
(4) Represents lease operating expenses, exclusive of production taxes, on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including net settlements and net change in fair value of unsettled derivatives related to natural 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	2015	2014	2013	2015-2014	2014-2013
Crude oil (MBbls)					
Wattenberg Field	6,490.4	4,026.7	2,783.1	61.2%	44.7 %
Utica Shale	493.4	295.2	122.8	67.1%	140.4 %
Other	—	—	3.8	*	*
Total	6,983.8	4,321.9	2,909.7	61.6%	48.5 %
Natural gas (MMcf)					
Wattenberg Field	30,752.8	17,108.9	12,724.3	79.7%	34.5 %
Utica Shale	2,548.9	2,152.9	561.1	18.4%	283.7 %
Other	—	36.2	2,145.8	*	(98.3)%
Total	33,301.7	19,298.0	15,431.2	72.6%	25.1 %
NGLs (MBbls)					
Wattenberg Field	2,615.9	1,605.7	1,034.4	62.9%	55.2 %
Utica Shale	219.4	150.5	8.8	45.8%	*
Total	2,835.3	1,756.2	1,043.2	61.4%	68.3 %
Crude oil equivalent (MBoe)					
Wattenberg Field	14,231.7	8,483.8	5,938.2	67.8%	42.9 %
Utica Shale	1,137.7	804.6	225.2	41.4%	257.3 %
Other	—	6.0	361.3	*	(98.3)%
Total	15,369.4	9,294.4	6,524.7	65.4%	42.4 %

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

Average Sales Price by Operating Region (excluding net settlements on derivatives)	Year Ended December 31, 2015	2014	2013	Change 2015-2014	2014-2013
Crude oil (per Bbl)					
Wattenberg Field	$ 40.03	$ 80.61	$ 89.83	(50.3)%	(10.3)%
Utica Shale	41.59	81.52	91.90	(49.0)%	(11.3)%
Other	—	—	92.88	*	*
Weighted-average price	40.14	80.67	89.92	(50.2)%	(10.3)%
Natural gas (per Mcf)					
Wattenberg Field	2.06	3.94	3.25	(47.7)%	21.2 %
Utica Shale	1.85	3.35	2.74	(44.8)%	22.3 %
Other	—	3.90	3.31	*	17.8 %
Weighted-average price	2.04	3.87	3.24	(47.3)%	19.4 %
NGLs (per Bbl)					
Wattenberg Field	10.58	25.95	27.83	(59.2)%	(6.8)%
Utica Shale	12.43	42.76	43.70	(70.9)%	(2.2)%
Weighted-average price	10.72	27.39	27.97	(60.9)%	(2.1)%
Crude oil equivalent (per Bbl)					
Wattenberg Field	24.64	51.10	53.91	(51.8)%	(5.2)%
Utica Shale	24.59	46.87	58.68	(47.5)%	(20.1)%
Other	—	23.42	20.59	*	13.7 %
Weighted-average price	24.64	50.72	52.23	(51.4)%	(2.9)%

* 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, 2015	2014
	(in millions)	
Increase in production	$ 298.5	$ 159.5
Decrease in average crude oil price	(283.1)	(40.0)
Increase (decrease) in average natural gas price	(60.9)	12.1
Decrease in average NGLs price	(47.2)	(1.0)
Total increase (decrease) in crude oil, natural gas and NGLs sales revenue	$ (92.7)	$ 130.6

Crude oil, natural gas and NGLs sales in 2015 decreased 20% compared to 2014. The decrease was primarily attributable to a significant decrease in commodity prices, resulting in a 51% decline in the price of a barrel of crude oil equivalent in 2015 compared to 2014. The decrease was offset in part by higher volumes sold in 2015 of 15.4 million Boe, up from 9.3 million Boe in 2014. Our average daily sales volumes increased to 42 MBoe per day in 2015 compared to 25 MBoe per day in 2014, as a result of continued drilling and completion activities as discussed in *Operational Overview*.

Crude oil, natural gas and NGLs sales in 2014 increased 38% compared to 2013. The increase was primarily attributable to significantly higher volumes sold, in particular liquids, which resulted in a liquids percentage of total production of approximately 65% in 2014. Our average daily sales volumes increased to 25 MBoe per day in 2014 compared to 18 MBoe per day in 2013, primarily due to the success of the horizontal Niobrara and Codell drilling program in the Wattenberg Field. Contributing to the increase in crude oil, natural gas and NGLs sales was a 19% increase in the average price of natural gas in 2014 over 2013.

We continued to experience high line pressures on the midstream system in the Wattenberg Field in the first half of 2015, but the Lucerne II processing plant and additional new compressor stations on the gathering system began initial operations in June 2015, resulting in immediate reductions in line pressures. We have experienced further line pressure reductions in the fourth quarter of 2015, particularly in December of 2015 when our primary service provider, DCP Midstream, completed its Grand Parkway gas gathering project. As a result of the reductions in line pressures during the second half of 2015, production from our Wattenberg Field vertical wells increased by 35% in the second half of 2015 when compared to the first half. Further, we expect sustained relief of gathering system pressure on our primary gatherer's system through 2016, depending upon the impact of reduced drilling activity in the field going forward. Our secondary midstream service provider, which currently gathers and processes approximately 30% of our Wattenberg Field gas, has indicated it will have limitations on its capital program in 2016, which may result in a curtailment of certain of our projected 2016 volumes. We rely on our third-party midstream service providers to construct compression, gathering and processing facilities to keep pace with our production growth. As a result, the timing and availability of additional facilities going forward is beyond our control. Falling commodity prices have resulted in reduced investment in midstream facilities by some third parties, increasing the risk that sufficient midstream infrastructure will not be available in future periods.

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 NGLs prices are among the most volatile of all commodity prices. The price of crude oil decreased during the second half of 2015 compared to the first half of 2015 amid continuing concerns regarding high U.S. inventories and slowing global demand for crude oil. Natural gas prices in 2015 were at significantly lower levels than the comparable periods of 2014. NGL prices declined significantly during 2015 and, while they have stabilized somewhat, also remain at low levels relative to those experienced in 2014. See *Item 1 and 2. Business and Properties - Business Segments - Oil and Gas Exploration and Production* for additional information regarding the marketing and pricing provisions of our crude oil, natural gas and NGLs.

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 a portion of our crude oil production, from the Wattenberg Field and for crude oil from the Utica Shale 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 pipeline 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 and recognize transportation, gathering and processing expenses as a component of production costs. As a result of the White Cliffs agreement, our Wattenberg Field crude oil average sales price increased approximately $1.28 per barrel in 2015 attributable to recognizing these costs for transportation on the White Cliffs pipeline as an increase in transportation expense, rather than a deduction from revenues.

Lease Operating Expenses

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, an increase of $3.4 million for additional wages and employee benefits, including costs for additional contract labor, $2.0 million for workover and maintenance related projects, $1.4 million to mitigate high line pressures in the Wattenberg Field, including costs for the rental of additional compressors, $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 were $3.71 and $4.56 for 2015 and 2014, respectively.

Lease operating expenses were $42.4 million in 2014 compared to $33.8 million in 2013. The $8.6 million increase in lease operating expenses in 2014 as compared to 2013 was primarily due to an increase of $2.9 million to mitigate high line pressures in the Wattenberg Field, including costs for the rental of additional compressors, as well as additional well maintenance incurred in order to increase the operating efficiency of older vertical wells, $1.1 million for workover and maintenance related projects, including additional costs incurred for the plugging of older vertical wells, $1.9 million for environmental compliance and remediation projects, $1.9 million for lease operating expenses incurred on the increasing number of non-operated wells and $1.0 million in additional wages and benefits due to increased headcount. Lease operating expenses per Boe were $4.56 and $5.18 for 2014 and 2013, respectively.

Production Taxes

Production taxes are directly related to crude oil, natural gas and NGLs sales. The $7.2 million, or 28%, decrease in production taxes for 2015 compared to 2014 is primarily related to the 20% decrease in crude oil, natural gas and NGLs sales and lower production tax rates. Similarly, the $3.9 million, or 18%, increase in production taxes for 2014 compared to 2013 is primarily related to the 38% increase in crude oil, natural gas and NGLs sales.

Transportation, Gathering and Processing Expenses

The $5.6 million, or 121%, increase in transportation, gathering and processing expenses for 2015 compared to 2014 was mainly attributable to oil transportation cost on the White Cliffs pipeline in the Wattenberg Field as we began delivering crude oil to the pipeline at the beginning of July 2015. We expect to continue to incur these oil transportation costs pursuant to our long-term firm transportation agreement. The $0.6 million, or 11%, decrease in transportation, gathering and processing expenses for 2014 compared to 2013 was primarily attributable to a $2.5 million reduction in our unutilized takeaway capacity and other transportation costs resulting from the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties and a $0.4 million decrease in compressor and refrigeration unit rentals in the Utica Shale, offset by a $2.3 million net increase in transportation and processing expenses due to higher production levels, primarily in the Utica Shale region.

Commodity Price Risk Management, Net

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. Because we sell all of our natural gas and crude oil production at prices similar to the indexes inherent in our derivative instruments, adjusted for certain fees and surcharges stipulated in the applicable sales agreements, we ultimately realize a price, before contract fees, 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 related to our swaps, less deductions. See Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report and Item 7A, *Quantitative and Qualitative Disclosures About Market Risk*, for a discussion of how each derivative type impacts our cash flows and a detailed presentation of our derivative positions as of December 31, 2015.

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 natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, *Fair Value of Financial Instruments*, and Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report for additional details of our derivative financial instruments.

Net settlements are primarily the result of crude oil and natural gas index prices at maturity of our derivative instruments compared to the respective strike prices. Net change in fair value of unsettled derivatives is comprised of the net asset increase or decrease in the beginning-of-period fair value of derivative instruments that settled during the period and the net change in fair value of unsettled derivatives during the period. The corresponding impact of settlement of the derivative instruments that settled during the period is included in net settlements for the period as discussed above. Net change in fair value of unsettled derivatives during the period is primarily related to shifts in the crude oil and natural gas forward curves and changes in certain differentials. See Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report for a detailed description of net settlements on our various derivatives.

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

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Commodity price risk management gain (loss), net:			
Net settlements:			
Natural gas	$ 30.0	$ (3.1)	$ 14.3
Crude oil	208.9	2.3	(3.1)
Total net settlements	238.9	(0.8)	11.2
Change in fair value of unsettled derivatives:			
Reclassification of settlements included in prior period changes in fair value of derivatives	(186.9)	13.3	(28.7)
Natural gas fixed price swaps	40.5	30.6	4.3
Natural gas basis swaps	(1.4)	—	(4.3)
Natural gas collars	12.8	11.1	3.8
Crude oil fixed price swaps	57.0	206.5	(9.1)
Crude oil collars	42.3	49.6	(1.1)
Net change in fair value of unsettled derivatives	(35.7)	311.1	(35.1)
Total commodity price risk management gain (loss), net	$ 203.2	$ 310.3	$ (23.9)

Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in commodity prices, cash settlements upon maturity of derivative instruments and the change in fair value of unsettled derivatives, and volumes sold and purchased.

The following table presents the components of sales from and costs of natural gas marketing:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Natural gas sales revenue	$ 10.4	$ 71.4	$ 68.9
Net settlements from derivatives	0.8	(0.2)	0.5
Net change in fair value of unsettled derivatives	(0.3)	0.4	0.4
Total sales from natural gas marketing	10.9	71.6	69.8
Costs of natural gas purchases	10.3	70.1	68.1
Net settlements from derivatives	0.7	(0.3)	0.3
Net change in fair value of unsettled derivatives	(0.3)	0.4	0.4
Other	1.0	1.8	1.3
Total costs of natural gas marketing	11.7	72.0	70.1
Natural gas marketing contribution margin	$ (0.8)	$ (0.4)	$ (0.3)

Natural gas sales revenue and cost of natural gas purchases decreased in 2015 compared to 2014 as our Gas Marketing segment markets less natural gas following the divestiture of our Appalachian Basin natural gas properties and due to the significant decrease in natural gas prices. Our Gas Marketing segment sold approximately 4.4 Bcf of natural gas at an average price of $1.37 per Mcf in 2015, compared to approximately 19.8 Bcf of natural gas at an average price of $3.39 per Mcf in 2014. Our Gas Marketing segment sold approximately 18.4 Bcf of natural gas at an average price of $3.48 per Mcf in 2013.

Derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical natural gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. See Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report and Item 7A, *Quantitative and Qualitative Disclosures About Market Risk*, for a discussion of how each derivative type impacts our cash flows and a detailed presentation of our derivative positions as of December 31, 2015.

As natural gas prices continue to remain depressed, certain third-party producers under our Gas Marketing segment have begun and may continue to experience financial distress, which has led to certain contractual defaults and litigation. To date, we have had no material counterparty default losses; however, we expect continued deterioration in the financial condition of some counterparties. In 2015, we recorded an allowance for doubtful accounts of approximately $0.5 million. We have initiated several legal actions for collection against some of the third-party producers, which have resulted in no collections and some of the third-party producers shutting-in their wells. As a result, 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. Although some third-party producers have defaulted on their firm transportation fees owed to us, RNG remains obligated to fulfill this commitment regardless of whether or not our third-party producers meet their commitments. As of December 31, 2015, the dollar commitment over the next several years related to this long-term firm transportation, sales and processing agreement was approximately $20.6 million.

Exploration Expense

The following table presents the major components of exploration expense:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Geological and geophysical costs	$ —	$ —	$ 0.7
Operating, personnel and other	1.1	0.9	5.6
Total exploration expense	$ 1.1	$ 0.9	$ 6.3

Geological and geophysical costs. Geological and geophysical costs in 2013 were primarily related to costs associated with reservoir studies in the Utica Shale.

Operating, personnel and other. The $4.7 million decrease in 2014 compared to 2013 is primarily related to a reduction in personnel costs in the Utica Shale resulting from the reassignment of former exploration department personnel to production departments and to general and administrative expense.

Impairment of Crude Oil and Natural Gas Properties

The following table sets forth the major components of our impairments of crude oil and natural gas properties expense:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Continuing operations:			
Impairment of proved and unproved properties	$ 154.6	$ 161.6	$ 49.7
Amortization of individually insignificant unproved properties	7.0	4.4	3.2
Other	—	0.8	—
Total impairment of crude oil and natural gas properties	$ 161.6	$ 166.8	$ 52.9

Impairment of proved and unproved properties. Due to a significant decline in commodity prices and a decrease in net-back realizations, we experienced a triggering event that required us to assess our crude oil and natural gas properties for possible impairment during the third quarter of 2015. As a result of our assessment, we recorded an impairment charge of $150.3 million to write-down our Utica Shale proved and unproved properties. Of this impairment charge, $24.7 million was recorded to write-down certain capitalized well costs on our Utica Shale proved producing properties. The impairment charge represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair value. The estimated fair value of approximately $27.9 million was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. Additionally, as a result of the current outlook for future commodity prices, we recorded an impairment charge of $125.6 million to write-down all of our Utica Shale lease acquisition costs and pad development costs for pads not in production. Further deterioration of commodity prices could result in additional impairment charges to our crude oil and natural gas properties.

In 2014, we recognized an impairment charge of $112.6 million to write-down certain capitalized well costs on our Utica Shale proved producing properties. The impairment charge represented the amount by which the carrying value of the Utica Shale proved producing properties exceeded the estimated fair value due to low commodity prices, large natural gas price differentials in the Appalachian Basin and changes in our Utica Shale drilling plans. The estimated fair value was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expected the crude oil and natural gas would be sold. The impairment charge was included in the consolidated statements of operations line item impairment of crude oil and natural gas properties. In 2014, we also recognized an impairment charge of $45.7 million to write-down certain capitalized leasehold costs on our Utica Shale unproved properties. The impairment was due to low commodity prices, large natural gas price differentials in the Appalachian Basin and changes in our Utica Shale drilling plans.

In 2013, we recognized an impairment charge of approximately $48.8 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania previously owned directly by us, as well as through our proportionate share of PDCM. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less the cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. See Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations,* to our consolidated financial statements included elsewhere in this report for additional details related to the sale of these properties.

Amortization of individually insignificant unproved properties. The increase in 2015 compared to 2014 was primarily related to a higher number of insignificant leases that were subject to amortization, primarily in the Utica Shale where we have altered drilling plans due to lower commodity prices and, as a result, expect certain leases to expire.

General and Administrative Expense

General and administrative expense decreased $33.6 million, or 27%, 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.

General and administrative expense increased $59.8 million, or 94%, in 2014 compared to 2013. The increase was mainly attributable to $40.3 million recorded in 2014 in connection with settlement of certain partnership-related class action litigation and litigation arising from bankruptcy proceedings of certain affiliated partnerships. Additional increases were an $13.0 million increase in payroll and employee benefits, of which $4.0 million was related to stock-based compensation, and a $4.6 million increase in legal fees, primarily related to the aforementioned partnership-related class action litigation, consulting and other professional services.

Depreciation, Depletion and Amortization

Crude oil and natural gas properties. 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 $298.8 million, $188.5 million and $111.6 million in 2015, 2014 and 2013, 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,	
	2015	2014
	(in millions)	
Increase in production	$ 123.4	$ 48.9
Increase (decrease) in weighted-average depreciation, depletion and amortization rates	(13.1)	28.0
Total increase in DD&A expense related to crude oil and natural gas properties	$ 110.3	$ 76.9

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

	Year Ended December 31,		
Operating Region/Area	2015	2014	2013
		(per Boe)	
Wattenberg Field	$ 20.13	$ 19.26	$ 17.68
Utica Shale	10.74	31.19	24.87
Other	—	—	2.66
Total weighted-average	19.44	20.28	17.05

The decrease in the Utica Shale DD&A expense rate in 2015 compared to 2014 was primarily due to the effect of impairments recorded in December 2014 and September 2015 to write-down certain capitalized well costs on our Utica Shale proved producing properties, which lowered the net book value of the properties by approximately $137.3 million. As a result of the decrease in proved developed reserves in 2015 as compared to 2014, we expect the weighted-average DD&A expense rate in 2016 to increase as compared to 2015. The increase in the Utica Shale DD&A expense rate in 2014 compared to 2013 was mainly the result of depleting the entire capitalized well costs of a Utica Shale horizontal well that experienced a mechanical failure in 2014.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $4.5 million for 2015 compared to $4.1 million for 2014 and $4.0 million for 2013.

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations ("ARO") for 2015 increased by $2.9 million, or 84%, compared to 2014. The increase in 2015 is primarily attributable to a decrease in the estimated useful life of certain vertical wells in the Wattenberg Field and increased plugging and abandonment of these wells to allow for horizontal drilling. As a result of the upward revision in estimated cash flows during 2015, we expect an increase in accretion expense for ARO in 2016 as compared to 2015. Accretion of ARO for 2014 decreased by $1.2 million, or 25%, compared to 2013. The decrease in 2014 is primarily attributable to the sale of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties in 2013.

Interest Expense

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 expense decreased by approximately $2.3 million in 2014 compared to 2013. The decrease is primarily comprised of a $1.8 million decrease attributable to an increase in capitalized interest in 2014.

Interest costs capitalized in 2015, 2014 and 2013 were $5.1 million, $3.5 million and $1.7 million, respectively.

Provision for Income Taxes

For 2015, the effective tax rate (the "rate") of 35.9% on loss from continuing operations differs from the statutory tax rate of 35% primarily due to state taxes, percentage depletion and domestic production deduction, partially offset by nondeductible expenses that consist primarily of officers' compensation and government lobbying expenses. For 2014, the rate of 39.5% on income from continuing operations differs from the statutory tax rate of 35% primarily due to state income taxes. The 2013 rate of 36.0% on loss from continuing operations differs from the statutory tax rate primarily due to state income taxes and the percentage depletion deduction, partially offset by nondeductible executive compensation. See Note 7, *Income Taxes*, to our consolidated financial statements included elsewhere in this report for our rate reconciliation for each of the years in the three-year period ended December 31, 2015.

As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. We continue voluntary participation in the Internal Revenue Service's ("IRS") Compliance Assurance Program (the "CAP Program") for the 2014, 2015 and 2016 tax years. We have received a partial acceptance notice from the IRS for our filed 2014 federal tax return and the IRS's post filing review is continuing.

Discontinued Operations

Appalachian Marcellus Shale Assets. In October 2014, we completed the sale of our entire 50% 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. 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 all periods presented.

Piceance Basin and NECO. In June 2013, we divested our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets for total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. Following the sale, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been reported as discontinued operations for all periods presented in the accompanying consolidated statements of operations included in this report.

For operating results related to our discontinued operations, see Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations,* to our consolidated financial statements included elsewhere in this report.

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

The factors resulting in changes in net loss in 2015 and 2013 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 $22.2 million, $193.1 million and $22.8 million in 2015, 2014 and 2013, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, was $46.1 million and $37.7 million in 2015 and 2014, respectively, compared to an adjusted net income of $0.5 million in 2013. 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 market transactions and asset sales. In 2015, our primary sources of liquidity were net cash flows from operating activities of $411.1 million and the proceeds received from the March 2015 public offering of our common stock of approximately $203 million. We used a portion of the proceeds of the offering to repay all amounts then outstanding on our revolving credit facility and used the remaining amounts to fund a portion of our capital program.

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 manage this volatility through our use of derivatives. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. For instruments that mature in three years or less, our debt covenants restrict us from entering into hedges that would exceed 85% of our expected future production from total proved reserves for such related time period (proved developed producing, proved developed non-producing and proved undeveloped). For instruments that mature later than three years, but no more than our designated maximum maturity, our debt covenants limit us from entering into hedges that would exceed 85% of our expected future production from proved developed producing properties during that time period. In addition, we may choose not to hedge the maximum amounts permitted under our covenants. Therefore, we may still have significant fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production. Given current commodity prices and our hedge position, we expect that positive net settlements on our derivative positions will continue to be a significant positive component of our 2016 cash flows from operations.

Our 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 practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility. At December 31, 2015, we had a working capital surplus of $30.7 million compared to a surplus of $89.5 million at December 31, 2014. The reduction in working capital is primarily the result of classifying as a current liability the carrying value of the Convertible Notes, net of discount, as the stated maturity of the Convertible Notes is May 2016, offset in part by an decrease in accounts payable and an increase in the fair value of unsettled derivatives.

We ended 2015 with cash and cash equivalents of $0.9 million and availability under our revolving credit facility of $401.3 million, for a total liquidity position of $402.2 million, compared to $398.4 million at December 31, 2014. These amounts exclude an additional $250 million available under our revolving credit facility, subject to certain terms and conditions of the agreement. The increase in liquidity of $3.8 million, or 0.9%, was primarily attributable to net cash flows from operating activities of $411.1 million, and the proceeds received from the March 2015 public offering of our common stock of approximately $203 million, offset in part by capital expenditures of $604.7 million during 2015. Our liquidity position will be reduced by the cash payment of approximately $115 million upon the maturity of our Convertible Notes. With our current derivative position, liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our planned drilling operations in 2016.

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. Pursuant to this shelf registration, we sold approximately four million shares of our common stock in March 2015 in an underwritten public offering at a price to us of approximately $50.73 per share.

In recent periods, including the year ended December 31, 2015, we have been able to access borrowings under our revolving credit facility and to obtain proceeds from the issuance of securities. We cannot, however, assure this will continue to be the case in the future. In light of recent weakened commodity prices, we continue to monitor market conditions and their potential impact on each of our revolving credit facility lenders, many of which are counterparties in our derivative transactions. In addition, 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. Our revolving credit facility borrowing base is subject to a redetermination each May and November, based upon a quantification of our proved reserves at each June 30 and December 31, respectively. In September 2015, we completed the semi-annual redetermination of our revolving credit facility, which resulted in the reaffirmation of our borrowing base at $700 million. Further, we entered into a Second Amendment to Third Amended and Restated Credit Agreement that extended the maturity date of our revolving credit facility to May 2020. However, we have elected to maintain the aggregate commitment level at $450 million. We had $37.0 million outstanding on our revolving credit facility as of December 31, 2015. 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 4.25 times the trailing 12 months earnings before interest, taxes, depreciation, depletion and amortization, change in fair value of unsettled derivatives, exploration expense, gains (losses) on sales of assets and other non-cash, extraordinary or non-recurring gains (losses) ("EBITDAX") and (ii) an adjusted current ratio of at least 1.0 to 1.0. 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 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, 2015, we were in compliance with all debt covenants with a 1.4 times debt to EBITDAX ratio and a 1.7 to 1.0 current ratio. We expect to remain in compliance throughout the next year.

The indenture governing our 7.75% senior notes due 2022 contains customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (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, 2015, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

Pursuant to the indenture governing the Convertible Notes, the conversion rights on our Convertible Notes were triggered on November 15, 2015. We have elected to settle the $115 million principal amount of the notes in cash and issue common stock for the excess conversion value upon maturity in May 2016. We expect to fund the cash settlement of any such conversion from working capital and/or borrowings under our revolving credit facility.

See Part II, Item 7A, *Quantitative and Qualitative Disclosures about Market Risk*, for our discussion of credit risk.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our derivative positions, operating costs and general and administrative expenses. Cash flows provided by operating activities increased in 2015 compared to 2014. The $174.4 million increase in cash provided by operating activities was primarily due to the increase in net settlements from our derivative positions 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 partially 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. Cash flows provided by operating activities increased in 2014 compared to 2013. The $77.5 million increase was mainly attributable to the increase in crude oil, natural gas and NGLs sales of $130.6 million and the decrease in changes in assets and liabilities of $35.1 million related to the timing of cash payments and receipts. These increases were offset in part by increases in general and administrative expense of $59.8 million, lease operating costs of $8.6 million and the decrease in net settlements on derivative positions of $15.1 million. The key components for the changes in our cash flows provided by operating activities are described in more detail in *Results of Operations* above.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $170.6 million in 2015 and $42.4 million in 2014 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 $9.7 million and $13.5 million in 2015 and 2014, respectively.

Adjusted EBITDA, a non-U.S. GAAP financial measure, increased by $78.9 million in 2015 from 2014, primarily as a result of the increase in net settlements from our derivative positions 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, an $88.8 million decrease in contribution margins from discontinued operations and a $14.6 million increase in lease operating costs. Adjusted EBITDA increased by $122.9 million in 2014 from 2013, primarily due to a $130.6 million increase in crude oil, natural gas and NGLs sales and a $72.3 million increase in contribution margins related to divested crude oil and natural gas assets, offset in part by a $59.8 million increase in general and administrative expense, an $8.6 million increase in lease operating costs and a $12.1 million decrease in net settlements on derivatives.

See *Reconciliation of Non-U.S. GAAP Financial Measures*, below, for a more detailed discussion of non-U.S. GAAP financial measures.

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 commit 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 expenditures. We would not be able to maintain our current level of crude oil, natural gas and NGLs production and cash flows from operating activities if capital markets were unavailable, commodity prices were to become depressed for a prolonged period and/or the borrowing base under our revolving credit facility was significantly reduced. The occurrence of such an event may result in our election to defer a substantial portion of our planned capital expenditures and could have a material negative impact on our operations in the future.

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. Our drilling program during the majority of 2015 consisted of five automated drilling rigs operating in the horizontal Niobrara and Codell plays in our Wattenberg Field. We reduced our rig count to four automated drilling rigs in December 2015. See Part I, *Items 1 and 2, Business and Properties - Properties - Drilling Activities*, for additional details on our drilling activities. 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 $628.6 million, offset in part by the $152.8 million net cash proceeds received from the sale of our entire 50% ownership interest in PDCM. Net cash used in investing activities of $217.1 million during 2013 was primarily related to cash utilized for our drilling operations of $394.9 million, offset in part by the $187.5 million received from the sale of properties and equipment, including acquisition adjustments. In 2013, we also paid approximately $9.7 million for the acquisition of crude oil and natural gas properties.

Financing Activities. Net cash from financing activities in 2015 was primarily related to the $202.9 million 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. Net cash from financing activities in 2013 was primarily related to the $275.8 million received from the issuance of our common stock in August 2013, partially offset by net payments of approximately $23.3 million to pay down amounts borrowed under revolving credit facilities.

Contractual Obligations and Contingent Commitments

The following table presents our contractual obligations and contingent commitments as of December 31, 2015:

	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)	$ 652.0	$ 115.0	$ —	$ 37.0	$ 500.0
Derivative contracts (3)	2.3	1.6	0.7	—	—
Capital leases (4)	1.4	0.4	1.0	—	—
Production tax liability	45.5	26.5	19.0	—	—
Asset retirement obligations	89.5	5.5	12.9	14.0	57.1
Other liabilities (5)	4.3	0.3	1.3	1.5	1.2
	795.0	149.3	34.9	52.5	558.3
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	275.8	42.9	82.5	81.0	69.4
Operating leases	10.5	2.4	4.1	3.9	0.1
Firm transportation and processing agreements (8)	84.6	17.6	33.4	26.4	7.2
	370.9	62.9	120.0	111.3	76.7
Total	$ 1,165.9	$ 212.2	$ 154.9	$ 163.8	$ 635.0

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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 $1.9 million of unamortized debt discount and $7.8 million of unamortized debt issuance costs. See Note 8, Long-Term Debt, to our consolidated financial statements included elsewhere in this report.

(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. See Note 8, Long-Term Debt, to our consolidated financial statements included elsewhere in this report. 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. See Note 12, Commitments and Contingencies - Partnership Repurchase Provision; Employment Agreements with Executive Officers, to our consolidated financial statements included elsewhere in this report.

(7) Amounts presented include $263.2 million to the holders of our 7.75% senior notes due 2022 and $1.4 million payable to the holders of our 3.25% convertible senior notes due 2016. Amounts also include $11.0 million payable to the participating banks in our revolving credit facility, of which interest of $6.6 million is related to unutilized commitments at a rate of 0.38% per annum, $4.3 million related to the outstanding borrowings on our revolving credit facility of $37.0 million and $0.2 million related to our undrawn letters of credit.

(8) Represents our gross commitment. See Note 12, Commitments and Contingencies - Firm Transportation, Processing and Sales Agreements, to our consolidated financial statements included elsewhere in this report.

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.

For information regarding our legal proceedings, see Note 12, *Commitments and Contingencies – Litigation*, to our consolidated financial statements included elsewhere in this report. From time to time, we are a party to various other 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 portrayal 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 Note 2, *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.

Exploration costs, including geological and geophysical expenses, 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 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 crude oil and natural gas properties. 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 two months later. Historically, these differences have been immaterial.

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.

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, 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 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, 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 derivative instruments are initially recorded to accounts receivable or payable, as applicable, and may not be received from or paid to counterparties to our derivative contracts within the same accounting period. Such settlements typically occur the month following the maturity of the derivative instrument. We have evaluated the credit risk of the counterparties holding our 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 derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our counterparties on the fair value of our 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, which could differ from actual results, achieved in future periods. 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 Acquisitions Using Purchase Accounting. We utilize the purchase method to account for acquisitions. 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; 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 values 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 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 Note 2, *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. See the Consolidated Statements of Cash Flows included elsewhere in this report.

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 effect. 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 our mark-to-market adjustments resulting from net changes in the fair value of unsettled derivatives.

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 crude oil and natural gas properties, depreciation, depletion and amortization, accretion of asset retirement obligations and loss on debt extinguishment, 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 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
- viability of acquisition opportunities and capital expenditure 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% 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 and sophisticated investors 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,		
	2015	2014	2013
		(in millions)	
Adjusted cash flows from operations:			
Adjusted cash flows from operations	$ 420.8	$ 250.2	$ 207.8
Changes in assets and liabilities	(9.7)	(13.5)	(48.6)
Net cash from operating activities	$ 411.1	$ 236.7	$ 159.2
Adjusted net income (loss):			
Adjusted net income (loss)	$ (46.1)	$ (37.7)	$ 0.5
Gain on commodity derivative instruments	203.2	309.3	(23.7)
Net settlements on commodity derivative instruments	(239.0)	2.0	(13.1)
Tax effect of above adjustments	13.6	(118.2)	14.0
Net income (loss)	$ (68.3)	$ 155.4	$ (22.3)
Adjusted EBITDA to net income (loss):			
Adjusted EBITDA	$ 443.2	$ 364.3	$ 241.4
Gain on commodity derivative instruments	203.2	309.3	(23.7)
Net settlements on commodity derivative instruments	(239.0)	2.0	(13.1)
Interest expense, net	(42.8)	(48.6)	(51.4)
Income tax provision	38.3	(99.2)	12.6
Impairment of crude oil and natural gas properties	(161.6)	(167.3)	(53.8)
Depreciation, depletion and amortization	(303.3)	(201.7)	(129.5)
Accretion of asset retirement obligations	(6.3)	(3.4)	(4.8)
Net income (loss)	$ (68.3)	$ 155.4	$ (22.3)
Adjusted EBITDA to net cash from operating activities:			
Adjusted EBITDA	$ 443.2	$ 364.3	$ 241.4
Interest expense, net	(42.8)	(48.6)	(51.4)
Stock-based compensation	20.1	17.5	12.9
Amortization of debt discount and issuance costs	7.0	6.9	6.8
(Gain) loss on sale of properties and equipment	(0.4)	(76.0)	3.7
Other	(6.3)	(13.9)	(5.6)
Changes in assets and liabilities	(9.7)	(13.5)	(48.6)
Net cash from operating activities	$ 411.1	$ 236.7	$ 159.2
PV-10:			
PV-10	$ 1,337.5	$ 3,450.1	$ 2,703.9
Present value of estimated future income tax discounted at 10%	(240.6)	(1,143.6)	(921.7)
Standardized measure of discounted future net cash flows	$ 1,096.9	$ 2,306.5	$ 1,782.2

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, cash equivalents and restricted cash accounts and the interest we pay on borrowings under our revolving credit facility. Our 7.75% senior notes due 2022 and our Convertible 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, 2015, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash, cash equivalents and restricted cash as of December 31, 2015 was $0.7 million, with a weighted-average interest rate of 0.1%. Based on a sensitivity analysis of our interest bearing deposits as of December 31, 2015, it was estimated that if market interest rates would have increased 1% in 2015, the impact of the interest income would have been insignificant.

As of December 31, 2015, excluding the $11.7 million irrevocable standby letter of credit, we had a $37.0 million outstanding balance on our revolving credit facility. It was estimated that if market interest rates would have increased or decreased 1%, our 2015 interest expense would have changed by approximately $0.4 million.

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 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 derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our derivative positions related to crude oil and natural gas sales in effect as of December 31, 2015:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
	Quantity *(Gas - BBtu* (1) *Oil - MBbls)*	Weighted-Average Contract Price		Quantity *(Gas - BBtu* (1) *Oil - MBbls)*	Weighted-Average Contract Price		Weighted-Average Contract Price	Fair Value December 31, 2015 (2) *(in millions)*
Commodity/ Index/ Maturity Period		Floors	Ceilings			Quantity *(BBtu)* (1)		
Natural Gas								
NYMEX								
2016	7,820.0	$ 3.88	$ 4.24	21,930.0	$ 3.93	27,600.0	$ (0.29)	$ 41.2
2017	7,920.0	3.59	4.13	24,590.0	3.62	12,000.0	(0.28)	26.5
2018	1,230.0	3.00	3.67	13,830.0	3.05	—	—	2.1
Total Natural Gas	16,970.0			60,350.0		39,600.0		$ 69.8
Crude Oil								
NYMEX								
2016	1,740.0	$ 77.59	$ 97.55	2,400.0	$ 90.37	—	$ —	$ 178.8
2017	960.0	54.06	73.77	480.0	56.99	—	—	15.1
Total Crude Oil	2,700.0			2,880.0		—		193.9
Total Natural Gas and Crude Oil								**$ 263.7**

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(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 34.3% of the fair value of our derivative assets were measured using significant unobservable inputs (Level 3). See Note 3, Fair Value Measurements, to the consolidated financial statements included elsewhere in this report.

The following table presents average NYMEX, CIG and TETCO M-2 closing prices for crude oil and natural gas for the periods identified, as well as average sales prices we realized for our crude oil, natural gas and NGLs production:

	Year Ended December 31, 2015	Year Ended December 31, 2014
Average Index Closing Price:		
Crude oil (per Bbl)		
NYMEX	$ 48.80	$ 92.91
Natural gas (per MMBtu)		
NYMEX	$ 2.66	$ 4.42
CIG	2.44	4.17
TETCO M-2 (1)	1.49	3.35
Average Sales Price Realized:		
Excluding net settlements on derivatives		
Crude oil (per Bbl)	$ 40.14	$ 80.67
Natural gas (per Mcf)	2.04	3.87
NGLs (per Bbl)	10.72	27.39

(1) TETCO M-2 is an index price upon which a majority of our natural gas produced in the Utica Shale is sold.

Based on a sensitivity analysis as of December 31, 2015, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives in place, would have resulted in a decrease in the fair value of our derivative positions of $41.0 million, whereas a 10% decrease in prices would have resulted in an increase in fair value of $41.4 million.

See Note 3, *Fair Value of Financial Instruments*, and Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report for a summary of our open derivative positions, as well as a discussion of how we determine the fair value of and account for our derivative contracts.

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. As commodity prices continue to remain depressed, certain customers under our Gas Marketing segment have begun and may continue to experience financial distress, which has led to certain contractual defaults. To date, we have had no material counterparty default losses relating to customers in either 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 derivative financial instruments. See Note 4, *Derivative Financial Instruments*, to our consolidated financial statements included elsewhere in this report for more detail on our derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2015, it does not consider those exposures or positions which could arise after that date. As a result, 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

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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, 2015 and December 31, 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, 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, 2015, 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.

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for the presentation of debt issuance costs and deferred taxes in 2015 as well as the manner in which it accounts for discontinued operations in 2014.

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

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

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 22, 2016

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

As of December 31,	2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$ 850	$ 16,066
Accounts receivable, net	104,274	131,204
Fair value of derivatives	221,659	187,495
Prepaid expenses and other current assets	5,266	5,954
Total current assets	332,049	340,719
Properties and equipment, net	1,937,678	1,827,454
Assets held for sale	2,874	2,874
Fair value of derivatives	44,387	112,819
Other assets	53,555	47,274
Total Assets	$ 2,370,543	$ 2,331,140
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 92,613	$ 130,321
Production tax liability	26,524	21,314
Fair value of derivatives	1,595	570
Funds held for distribution	29,894	27,186
Current portion of long-term debt	112,940	—
Accrued interest payable	9,057	9,109
Other accrued expenses	28,709	62,717
Total current liabilities	301,332	251,217
Long-term debt	529,437	655,475
Deferred income taxes	143,452	184,867
Asset retirement obligation	84,032	71,992
Fair value of derivatives	695	197
Other liabilities	24,398	30,033
Total liabilities	1,083,346	1,193,781
Commitments and contingent liabilities		
Shareholders' equity		
Preferred shares - par value $0.01 per share, 50,000,000 shares authorized, none issued	—	—
Common shares - par value $0.01 per share, 150,000,000 authorized, 40,174,776 and 35,927,985 issued as of December 31, 2015 and 2014, respectively	402	359
Additional paid-in capital	907,382	689,209
Retained earnings	380,422	448,702
Treasury shares - at cost, 20,220 and 21,643 as of December 31, 2015 and 2014, respectively	(1,009)	(911)
Total shareholders' equity	1,287,197	1,137,359
Total Liabilities and Shareholders' Equity	$ 2,370,543	$ 2,331,140

See accompanying Notes to Consolidated Financial Statements

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

Year Ended December 31,	2015	2014	2013
Revenues			
Crude oil, natural gas and NGLs sales	$ 378,713	$ 471,413	$ 340,795
Sales from natural gas marketing	10,920	71,571	69,787
Commodity price risk management gain (loss), net	203,183	310,304	(23,919)
Well operations, pipeline income and other	2,510	2,919	6,002
Total revenues	595,326	856,207	392,665
Costs, expenses and other			
Lease operating expenses	56,992	42,402	33,817
Production taxes	18,443	25,615	21,758
Transportation, gathering and processing expenses	10,151	4,592	5,152
Cost of natural gas marketing	11,717	72,015	70,084
Exploration expense	1,102	947	6,334
Impairment of crude oil and natural gas properties	161,620	166,847	52,873
General and administrative expense	89,959	123,559	63,715
Depreciation, depletion and amortization	303,258	192,528	115,624
Accretion of asset retirement obligations	6,293	3,415	4,566
(Gain) loss on sale of properties and equipment	(385)	507	2,022
Total cost, expenses and other	659,150	632,427	375,945
Income (loss) from operations	(63,824)	223,780	16,720
Interest expense	(47,571)	(47,842)	(50,143)
Interest income	4,807	1,290	460
Income (loss) from continuing operations before income taxes	(106,588)	177,228	(32,963)
Provision for income taxes	38,308	(69,967)	11,852
Income (loss) from continuing operations	(68,280)	107,261	(21,111)
Income (loss) from discontinued operations, net of tax	—	48,174	(1,190)
Net income (loss)	$ (68,280)	$ 155,435	$ (22,301)
Earnings per share:			
Basic			
Income (loss) from continuing operations	$ (1.74)	$ 3.00	$ (0.65)
Income (loss) from discontinued operations, net of tax	—	1.34	(0.04)
Net income (loss)	$ (1.74)	$ 4.34	$ (0.69)
Diluted			
Income (loss) from continuing operations	$ (1.74)	$ 2.93	$ (0.65)
Income (loss) from discontinued operations, net of tax	—	1.31	(0.04)
Net income (loss)	$ (1.74)	$ 4.24	$ (0.69)
Weighted-average common shares outstanding:			
Basic	39,153	35,784	32,426
Diluted	39,153	36,678	32,426

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

Year Ended December 31,	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$ (68,280)	$ 155,435	$ (22,301)
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled derivatives	35,791	(311,281)	36,801
Depreciation, depletion and amortization	303,258	201,656	129,518
Impairment of crude oil and natural gas properties	161,620	167,280	53,802
Accretion of asset retirement obligation	6,293	3,455	4,747
Stock-based compensation	20,068	17,518	12,880
Excess tax benefits from stock-based compensation	(1,361)	(1,999)	(2,489)
(Gain) loss from sale of properties and equipment	(385)	(75,972)	3,722
Amortization of debt discount and issuance costs	7,040	6,938	6,783
Deferred income taxes	(41,415)	88,474	(15,883)
Other	(1,855)	(1,329)	170
Total adjustments to net income (loss) to reconcile to net cash from operating activities:	489,054	94,740	230,051
Changes in assets and liabilities:			
Accounts receivable	24,769	(34,598)	(41,509)
Other assets	(2,264)	(3,296)	3,461
Restricted cash	46	2,214	(8)
Production tax liability	(1,629)	3,358	4,121
Accounts payable and accrued expenses	(30,310)	21,453	(11,485)
Other liabilities	(313)	(2,617)	(3,165)
Total changes in assets and liabilities	(9,701)	(13,486)	(48,585)
Net cash from operating activities	411,073	236,689	159,165
Cash flows from investing activities:			
Capital expenditures	(604,668)	(628,592)	(394,948)
Acquisition of crude oil and natural gas properties, net of cash acquired	—	—	(9,658)
Proceeds from acquisition adjustments	—	—	7,579
Proceeds from sale of properties and equipment, net	405	154,457	179,919
Net cash from investing activities	(604,263)	(474,135)	(217,108)
Cash flows from financing activities:			
Proceeds from revolving credit facility	397,000	263,750	260,250
Repayment of revolving credit facility	(416,000)	(200,000)	(283,500)
Payment of debt issuance costs	(974)	(88)	(2,352)
Proceeds from sale of common stock, net of issuance costs	202,851	—	275,847
Excess tax benefits from stock-based compensation	1,361	1,999	2,489
Purchase of treasury shares	(6,056)	(5,392)	(4,133)
Principal payments under capital lease obligations	(208)	—	—
Proceeds from exercise of stock options	—	—	128
Net cash from financing activities	177,974	60,269	248,729
Net change in cash and cash equivalents	(15,216)	(177,177)	190,786
Cash and cash equivalents, beginning of year	16,066	193,243	2,457
Cash and cash equivalents, end of year	$ 850	$ 16,066	$ 193,243
Supplemental cash flow information:			
Cash payments for (receipts from):			
Interest, net of capitalized interest	$ 45,642	$ 46,809	$ 48,844
Income taxes	10,049	1,800	(3,014)
Non-cash investing activities:			
Change in accounts payable related to capital expenditures	(45,230)	39,667	33,328
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposal	14,030	33,250	2,112
Change in accounts receivable related to sale of properties and equipment	—	—	808
Change in other assets related to sale of properties and equipment	—	39,048	3,350
Purchase of properties and equipment under capital leases	1,601	—	—

See accompanying Notes to Consolidated Financial Statements

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

Year Ended December 31,	2015	2014	2013
Common shares, issued:			
Shares beginning of year	35,927,985	35,675,656	30,294,224
Shares issued pursuant to sale of equity	4,002,000	—	5,175,000
Exercise of stock options	7,720	—	10,763
Issuance of stock awards, net of forfeitures	237,071	253,032	212,926
Retirement of treasury shares	—	(703)	(17,257)
Shares end of year	40,174,776	35,927,985	35,675,656
Treasury shares:			
Shares beginning of year	21,643	5,508	5,059
Purchase of treasury shares	120,864	97,646	84,642
Issuance of treasury shares	(127,159)	(83,208)	(67,334)
Retirement of treasury shares	—	(703)	(17,257)
Non-employee directors' deferred compensation plan	4,872	2,400	398
Shares end of year	20,220	21,643	5,508
Common shares outstanding	40,154,556	35,906,342	35,670,148
Equity:			
Shareholders' equity			
Preferred shares, par value $0.01 per share:			
Balance beginning and end of year	$ —	$ —	$ —
Common shares, par value $0.01 per share:			
Balance beginning of year	359	357	303
Shares issued pursuant to sale of equity	40	—	52
Issuance of stock awards, net of forfeitures	3	2	2
Balance end of year	402	359	357
Additional paid-in capital:			
Balance beginning of year	689,209	674,211	387,494
Proceeds from sale of equity, net of issuance costs	202,811	—	275,795
Exercise of stock options	—	—	125
Stock-based compensation expense	20,207	17,851	12,402
Issuance of treasury shares	(6,206)	(4,817)	(3,270)
Retirement of treasury shares	—	(35)	(824)
Tax impact of stock-based compensation	1,361	1,999	2,489
Balance end of year	907,382	689,209	674,211
Retained earnings:			
Balance beginning of year	448,702	293,267	315,568
Net income (loss) attributable to shareholders	(68,280)	155,435	(22,301)
Balance end of year	380,422	448,702	293,267
Treasury shares, at cost:			
Balance beginning of year	(911)	(241)	(184)
Purchase of treasury shares	(6,055)	(5,392)	(4,133)
Issuance of treasury shares	6,206	4,817	3,271
Retirement of treasury shares	—	35	824
Non-employee directors' deferred compensation plan	(249)	(130)	(19)
Balance end of year	(1,009)	(911)	(241)
Total shareholders' equity	$ 1,287,197	$ 1,137,359	$ 967,594

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. (the "Company," "we," "us," or "our") is a domestic independent exploration and production company that produces, develops, acquires and explores for crude oil, natural gas and NGLs, with primary operations in the Wattenberg Field in Colorado and the Utica Shale in southeastern Ohio. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Ohio operations are focused in the Utica Shale play. As of December 31, 2015, we owned an interest in approximately 3,000 gross wells. We are engaged in two business segments: Oil and Gas Exploration and Production and Gas Marketing. In October 2014, we sold our entire 50% ownership interest in our joint venture, PDCM, to an unrelated third-party. See Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations,* for additional information.

The accompanying audited consolidated financial statements include the accounts of PDC, our wholly-owned subsidiary Riley Natural Gas ("RNG"), our proportionate share of our four affiliated partnerships and, for the year ended December 31, 2014 and 2013, our proportionate share of PDCM. As of December 31, 2015, we had four remaining affiliated partnerships that continue to conduct crude oil and natural gas producing activities. Pursuant to the proportionate consolidation method, our accompanying consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. 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, future cash flows from crude oil and natural gas properties, valuation of derivative instruments, impairment of proved and unproved properties and valuation of deferred income tax assets.

During the fourth quarter of 2015, we reclassified certain amounts within our costs and expenses in the consolidated statements of operations and assets and liabilities in the consolidated balance sheets. Specifically, production costs has been segregated into lease operating expenses, production taxes and transportation, gathering and processing expenses. This reclassification has been made to prior period financial statements to conform to the current year presentation. We believe these changes allow users of our financial statements to better understand our expense structure and make our financial statements more comparable to those of peer companies.

Further, we have noted the following misclassifications in prior year filings, which have been corrected in the current year presentation:

- Production-related general and administrative costs totaling $7.7 million and $3.8 million for 2014 and 2013, respectively, have been reclassified from production costs to general and administrative expense;
- Prepaid well costs write-offs totaling $3.3 million and $0.4 million for 2014 and 2013, respectively, have been reclassified from production costs to impairment of crude oil and natural gas properties; and
- Prepaid well costs totaling $27.3 million in the December 31, 2014 consolidated balance sheet have been reclassified from other assets to properties and equipment, net;

We evaluated the impact of these misclassifications and determined they were not material to the prior periods presented.

Additionally, as a result of adopting the accounting standards update on the balance sheet classification of debt issuance costs and deferred taxes, the following reclassifications have been made to the prior period financial statements:

- Debt issuance costs totaling $9.4 million in the December 31, 2014 consolidated balance sheet have been reclassified from other assets and are presented as a direct deduction from the carrying amount of long-term debt; and
- Current deferred income tax liabilities totaling $59.2 million in the December 31, 2014 consolidated balance sheet have been reclassified to non-current pursuant to the income tax accounting standards update issued and adopted in 2015.

These reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity.

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.

Restricted Cash. We are required by certain government agencies or agreements to maintain bonds or cash accounts for various operating activities. As of December 31, 2015 and 2014, we had collateral in the form of certificates of deposit and cash totaling $0.7 million included in other assets.

Inventory. Inventory consists of crude oil, stated at the lower of cost to produce or market, and other production supplies intended to be used in our crude oil and natural gas operations. As of December 31, 2015 and 2014, inventory of $0.6 million and $0.8 million, respectively, is included in prepaid expenses and other current assets on the consolidated balance sheets. Additionally, as of December 31, 2015, inventory for the White Cliffs pipeline line fill of $1.1 million is included in other assets on the consolidated balance sheets.

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 prohibits 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 derivative instruments as hedges. Accordingly, changes in the fair value of our derivative instruments are recorded in the consolidated statements of operations. Classification of net settlements resulting from maturities and changes in fair value of unsettled derivatives depends on the purpose for issuing or holding the derivative. 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 natural gas marketing.

The validation of the 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. See Note 3, *Fair Value of Financial Instruments*, and Note 4, *Derivative Financial Instruments*, for a discussion of our derivative fair value measurements and a summary fair value table of our open positions as of December 31, 2015 and 2014, respectively.

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 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 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. See Note 6, *Properties and Equipment*, for disclosures related to changes in our capitalized exploratory well costs, if any.

Proved Property Impairment. Upon a triggering event, 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 crude oil and natural gas properties, with a corresponding impact on accumulated DD&A on the consolidated balance sheets.

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 crude oil and natural gas properties.

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. There were no impairments to other property and equipment in 2015 and 2013, respectively. Total impairments to other property and equipment was $0.8 million in 2014.

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

Transportation and other equipment	3 - 20 years
Buildings	20 - 30 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 $4.5 million, $4.1 million and $4.0 million in 2015, 2014 and 2013, 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 $5.1 million, $3.5 million and $1.7 million in 2015, 2014 and 2013, respectively.

Assets Held for Sale. 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. 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, 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 $19.0 million and $26.4 million in December 31, 2015 and 2014, 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 bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax 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, 2015 and 2014, 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 capitalized as of December 31, 2015 and 2014 were $11.4 million and $13.7 million, respectively. The December 31, 2015 amount included $0.2 million in costs related to the issuance of our 3.25% convertible senior notes due 2016 and $7.6 million related to our 7.75% senior notes due 2022, both shown as a reduction in the related debt, and $3.6 million related to our revolving credit facility shown as a long-term asset. The December 31, 2014 amount included $0.7 million in costs related to the issuance of our 3.25% convertible senior notes due 2016, $8.7 million related to our 7.75% senior notes due 2022 and $4.3 million related to our revolving credit facility.

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 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. See Note 10, *Asset Retirement Obligations*, for a reconciliation of the changes in our asset retirement obligation.

Treasury Shares. We record treasury share purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions 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 method used. We use the "net-back" method of accounting for natural gas and NGLs, as well as a portion of our crude oil production, from the Wattenberg Field and for crude oil from the Utica Shale 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 pipeline 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.

Natural gas marketing. Natural gas marketing is reported on the gross method of accounting, based on the nature of the agreements between our natural 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 natural gas. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Natural 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 derivatives of the RNG commodity-based derivative transactions for natural gas marketing are included in sales from or cost of natural gas marketing, as applicable.

Well operations and pipeline income. We are paid a monthly operating fee for each well we operate and the natural gas transported for outside owners, including the affiliated partnerships we sponsor. Well operations and pipeline income is recognized when persuasive evidence of an arrangement exists, the sales price is fixed or determinable, services have been rendered and collection of revenues is reasonably assured.

Accounting for Acquisitions. We utilize the purchase method to account for acquisitions. 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. 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.

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 2015, 2014 and 2013.

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.

Interest Income. Interest income on our note receivable is recognized over its term using the effective interest method.

Recently Adopted Accounting Standards.

In November 2014, the FASB issued an update to accounting for derivatives and hedging instruments. The update clarifies how current accounting guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. Specifically, the accounting update clarifies that an entity should consider all relevant terms and features, including the embedded derivative feature being evaluated for bifurcation, in evaluating the nature of the host contract. Furthermore, the update clarifies that no single term or feature would necessarily determine the economic characteristics and risks of the host contract. Rather, the nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. The assessment of the substance of the relevant terms and features should incorporate a consideration of the characteristics of the terms and features themselves, the circumstances under which the hybrid financial instrument was issued or acquired, and the potential outcomes of the hybrid financial instrument, as well as the likelihood of those potential outcomes. The accounting update is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements.

In January 2015, the FASB issued new accounting guidance eliminating from current accounting guidance the concept of extraordinary items, which, among other things, required an entity to segregate extraordinary items considered to be unusual and infrequent from the results of ordinary operations and show the item separately in the income statement, net of tax, after income from continuing operations. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements.

In February 2015, the FASB issued an accounting update modifying existing consolidation guidance for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. The amendments in this update are effective for fiscal years and interim periods within those years beginning after December 15, 2015, and require either a retrospective or a modified retrospective approach to adoption. Early adoption is permitted. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements.

In April 2015, the FASB issued an accounting update simplifying the presentation of debt issuance costs and requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The update did not affect the recognition and measurement guidance for debt issuance costs. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements. See Note 1, *Nature of Operations and Basis of Presentation,* for the amounts reclassified in the December 31, 2014 consolidated balance sheet.

In July 2015, the FASB issued an accounting update requiring all entities to measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements.

In September 2015, the FASB issued an accounting update requiring adjustments to provisional amounts that are identified during the measurement period of a business combination to be recognized in the reporting period in which the adjustment amounts are determined. The accounting update also requires an entity to present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings, by line item, that would have been recorded in previous reporting periods if the adjustment to the estimated amounts had been recognized as of the acquisition date. This guidance is effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The accounting update should be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. We elected to early adopt this guidance on October 1, 2015. Adoption of this guidance did not have a significant impact on our consolidated financial statements.

In November 2015, the FASB issued an accounting update simplifying the presentation of deferred income taxes by requiring that all deferred tax liabilities and assets, along with any related valuation allowance, be classified as non-current in a classified statement of financial position. This guidance is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted. We elected to early adopt this guidance on October 1, 2015. See Note 1, *Nature of Operations and Basis of Presentation,* for the amounts reclassified in the December 31, 2014 consolidated balance sheet.

Recently Issued Accounting Standards.

In May 2014, the Financial Accounting Standards Board ("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 August 2015, the FASB deferred the effective date of the revenue standard to 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 currently evaluating the impact these changes may have on our consolidated financial statements.

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 will explicitly require management to assess an entity's ability to continue as a going concern 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. Adoption of this guidance is not expected to have a significant impact on our consolidated financial statements.

NOTE 3 - 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,					
	2015			2014		
	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)					
Assets:						
Commodity-based derivative contracts	$ 174,657	$ 91,288	$ 265,945	$ 237,939	$ 62,356	$ 300,295
Basis protection derivative contracts	101	—	101	19	—	19
Total assets	174,758	91,288	266,046	237,958	62,356	300,314
Liabilities:						
Commodity-based derivative contracts	738	—	738	742	—	742
Basis protection derivative contracts	1,552	—	1,552	25	—	25
Total liabilities	2,290	—	2,290	767	—	767
Net asset	$ 172,468	$ 91,288	$ 263,756	$ 237,191	$ 62,356	$ 299,547

The following table presents a reconciliation of our Level 3 assets measured at fair value:

	2015	2014	2013
	(in thousands)		
Fair value, net asset beginning of period	$ 62,356	$ 1,111	$ 13,610
Changes in fair value included in statement of operations line item:			
Commodity price risk management gain (loss), net	65,018	62,003	(1,748)
Sales from natural gas marketing	146	(22)	13
Settlements included in statement of operations line items:			
Commodity price risk management gain (loss), net	(36,169)	(737)	(6,361)
Sales from natural gas marketing	(63)	1	(37)
Loss from discontinued operations, net of tax	—	—	(4,366)
Fair value, net asset end of period	$ 91,288	$ 62,356	$ 1,111
Net change in fair value of unsettled derivatives included in statement of operations line item:			
Commodity price risk management gain (loss), net	$ 43,540	$ 15,632	$ (2,731)
Sales from natural gas marketing	—	3	4
Total	$ 43,540	$ 15,635	$ (2,727)

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.

Non-Derivative Financial Assets and Liabilities

The carrying value of the financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximate fair value due to the short-term maturities of these instruments. See Note 2, *Summary of Significant Accounting Policies - Properties and Equipment, Crude Oil and Natural Gas Properties* and *Asset Retirement Obligations,* for a discussion of how we determined fair value for these assets and liabilities.

The liability associated with our non-qualified deferred compensation plan for non-employee directors may be settled in cash or shares of our common stock. The carrying value of this obligation is based on the quoted market price of our common stock, which is a Level 1 input. The liability related to this plan, which was included in other liabilities on the consolidated balance sheets, was immaterial as of December 31, 2015 and 2014.

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 under the fair value option; however, as of

December 31, 2015, we estimate the fair value of the portion of our long-term debt related to our 3.25% convertible senior notes due 2016 to be $150.2 million, or 130.6% of par value, and the portion related to our 7.75% senior notes due 2022 to be $485.0 million, or 97.0% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs.

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 4 - 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 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 natural 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 derivatives in our natural 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 derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of December 31, 2015, we had derivative instruments, which were comprised of collars, fixed-price swaps, basis protection swaps and physical sales and purchases, in place for a portion of our anticipated production through 2018 for a total of 77,320 BBtu of natural gas and 5,580 MBbls of crude oil. The majority of our derivative contracts are entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices.

As of December 31, 2015, our derivative instruments were comprised of commodity swaps, collars, basis protection swaps and physical sales and purchases.

- Collars contain a fixed floor price 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;
- 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 2015, 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 derivatives for fixed-priced physical transactions where we sell or purchase third-party supply at fixed rates. These physical 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 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 natural 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, 2015 and 2014:

Derivative instruments:		Balance sheet line item	2015	2014
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$ 221,161	$ 186,886
	Related to natural gas marketing	Fair value of derivatives	441	590
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	57	19
			221,659	187,495
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	44,292	112,599
	Related to natural gas marketing	Fair value of derivatives	51	220
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	44	—
			44,387	112,819
Total derivative assets			$ 266,046	$ 300,314
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas marketing	Fair value of derivatives	$ 417	$ 545
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,178	25
			1,595	570
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	275	—
	Related to natural gas marketing	Fair value of derivatives	46	197
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	374	—
			695	197
Total derivative liabilities			$ 2,290	$ 767

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

Consolidated statement of operations line item	Year Ended December 31, 2015	2014	2013
		(in thousands)	
Commodity price risk management gain (loss), net			
Net settlements	$ 238,935	$ (837)	$ 11,177
Net change in fair value of unsettled derivatives	(35,752)	311,141	(35,096)
Total commodity price risk management gain (loss), net	$ 203,183	$ 310,304	$ (23,919)
Sales from natural gas marketing			
Net settlements	$ 778	$ (208)	$ 446
Net change in fair value of unsettled derivatives	(318)	364	429
Total sales from natural gas marketing	$ 460	$ 156	$ 875
Cost of natural gas marketing			
Net settlements	$ (745)	$ 346	$ (257)
Net change in fair value of unsettled derivatives	279	(451)	(412)
Total cost of natural gas marketing	$ (466)	$ (105)	$ (669)

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, 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

As of December 31, 2014	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	$ 300,314	$ (29)	$ 300,285
Liability derivatives:			
Derivative instruments, at fair value	$ 767	$ (29)	$ 738

NOTE 5 - CONCENTRATION OF RISK

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

	As of December 31,	
	2015	2014
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 41,873	$ 49,531
Joint interest billings	35,017	52,841
Derivative counterparties	24,437	12,582
Insurance reimbursement	879	11,212
Other	4,077	5,524
Allowance for doubtful accounts	(2,009)	(486)
Accounts receivable, net	$ 104,274	$ 131,204

Our accounts receivable primarily relate to sales of our crude oil, natural gas and NGLs production, other third parties that own working interests in the properties we operate and derivative counterparties. For the years ended December 31, 2015, 2014 and 2013, amounts written off to allowance for doubtful accounts were not material. As of December 31, 2015, we had one customer representing 10% or greater of our accounts receivable balance. Concord Energy represents 11.3% of our December 31, 2015 accounts receivable balance. As of December 31, 2014, we had two customers representing 10% or greater of our accounts receivable balance. Suncor Energy Marketing, Inc. and Concord Energy represented 11.1% and 10.3%, respectively.

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

	Year Ended December 31,		
Customer	2015	2014	2013
Concord Energy	23.2%	18.3%	—%
Suncor Energy Marketing, Inc.	14.3%	19.7%	35.9%
Shell Trading Company	13.8%	—%	—%
DCP Midstream, LP	13.2%	15.1%	13.9%
Teppco Crude Oil, LLC	—%	12.9%	8.0%

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

Derivative Counterparties. A significant portion of our liquidity is concentrated in 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 derivative contracts. 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, 2015, taking into account the estimated likelihood of nonperformance.

The following table presents the counterparties that expose us to credit risk as of December 31, 2015, with regard to our derivative assets:

Counterparty Name		Fair Value of Derivative Assets As of December 31, 2015
		(in thousands)
Canadian Imperial Bank of Commerce (1)	$	78,102
JP Morgan Chase Bank, N.A (1)		71,012
Bank of Nova Scotia (1)		49,758
Wells Fargo Bank, N.A. (1)		32,474
NATIXIS (1)		29,754
Other lenders in our revolving credit facility		4,856
Other (2)		90
Total	$	266,046

(1) Major lender in our revolving credit facility. See Note 8, Long-Term Debt.
(2) Represents one counterparty.

Note Receivable

The following table presents information regarding our note receivable outstanding as of December 31, 2015:

		Amount
		(in thousands)
Note receivable:		
Principal outstanding, December 31, 2014	$	39,707
Paid-in-kind interest		3,362
Principal outstanding, December 31, 2015	$	43,069

In October 2014, we sold our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations*, for additional information regarding the sale. 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 8% 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. As of December 31, 2015, 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. The Note is secured by a pledge of stock in certain subsidiaries of the unrelated third-party, debt securities and other assets.

Under the effective interest method, we recognized $4.5 million and $0.9 million of interest income for the years ended December 31, 2015 and 2014, respectively, of which $3.4 million and $0.7 million, respectively, was PIK Interest. As of December 31, 2015 and 2014, the $43.1 million and $39.7 million, respectively, outstanding balance on the Note was included in the consolidated balance sheet line item other assets.

NOTE 6 - PROPERTIES AND EQUIPMENT

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

	As of December 31,	
	2015	2014
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 2,881,189	$ 2,267,165
Unproved	60,498	188,206
Total crude oil and natural gas properties	2,941,687	2,455,371
Equipment and other	30,098	29,562
Land and buildings	9,015	9,015
Construction in progress	113,115	165,205
Properties and equipment, at cost	3,093,915	2,659,153
Accumulated DD&A	(1,156,237)	(831,699)
Properties and equipment, net	$ 1,937,678	$ 1,827,454

The following table presents impairment charges recorded for crude oil and natural gas properties:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Continuing operations:			
Impairment of proved and unproved properties	$ 154,608	$ 161,604	$ 49,631
Amortization of individually insignificant unproved properties	7,012	4,465	3,242
Other	—	778	—
Total continuing operations	161,620	166,847	52,873
Discontinued operations:			
Impairment of proved and unproved properties	—	433	566
Amortization of individually insignificant unproved properties	—	—	363
Total discontinued operations	—	433	929
Total impairment of crude oil and natural gas properties	$ 161,620	$ 167,280	$ 53,802

In 2015, due to a significant decline in commodity prices and a decrease in net-back realizations, we experienced a triggering event that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessment, we recorded an impairment charge of $150.3 million to write-down our Utica Shale proved and unproved properties. Of this impairment charge, $24.7 million was recorded to write-down certain capitalized well costs on our Utica Shale proved producing properties. This impairment charge represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair value. The estimated fair value of approximately $27.9 million, excluding estimated salvage value, was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. Additionally, as a result of the current outlook for future commodity prices, we recorded an impairment charge of $125.6 million to write-down all of our Utica Shale lease acquisition costs and pad development costs for pads not in production. These impairment charges were included in the consolidated statements of operations line item impairment of crude oil and natural gas properties.

In 2014, we recognized an impairment charge of $158.3 million to write-down our Utica Shale producing and non-producing crude oil and natural gas properties to their estimated fair value, $112.6 million of which was for capitalized well costs on proved producing properties and $45.7 million for capitalized leasehold costs on unproved properties. The impairment charge represented the amount by which the carrying value of the Utica Shale crude oil and natural gas properties exceeded the estimated fair value and was therefore not recoverable. The estimated fair value was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. The impairment charge was included in the consolidated statements of operations line item impairment of crude oil and natural gas properties.

In 2013, we recognized an impairment charge of approximately $48.8 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania previously owned directly by us, as well as through our proportionate share of PDCM. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less the cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. The impairment charge was included in the consolidated statements of operations line item impairment of crude oil and natural gas properties. See Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations,* for additional information regarding these properties.

Suspended Well Costs

As of December 31, 2015 and 2014, there were no suspended well costs or wells pending determination.

NOTE 7 - 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,		
	2015	2014	2013
		(in thousands)	
Current:			
Federal	$ (2,944)	$ (1,514)	$ 1,355
State	(163)	966	199
Total current income taxes	(3,107)	(548)	1,554
Deferred:			
Federal	37,352	(60,698)	8,238
State	4,063	(8,721)	2,060
Total deferred income taxes	41,415	(69,419)	10,298
Income tax benefit (expense) from continuing operations	$ 38,308	$ (69,967)	$ 11,852

In the last three years, we continued to utilize tax deferral strategies such as bonus depreciation, accelerated depreciation and intangible drilling cost ("IDC") expense elections or accelerated IDC amortization to minimize our current taxes. In 2013 these deferral strategies enabled us to offset any taxable gain on the sale of our non-core Colorado assets and also preserved some of our NOLs to carry forward for use against our anticipated 2014 taxable income. In 2014, these same deferral strategies, along with carried forward federal and state NOLs, credits, and suspended deductions, permitted us to offset the majority of the tax gain on the sale of PDCM. See Note 15, *Assets Held for Sale, Divestitures and Discontinued Operations,* for additional information regarding the sale of our non-core Colorado assets and the sale of our entire 50% ownership interest in PDCM. In 2015, these continued deferral strategies offset the tax adjustments for impairments to crude oil and natural gas properties and negative net change in fair value of unsettled derivatives to enable our current income taxes to be minimized.

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,		
	2015	2014	2013
Statutory tax rate	35.0%	35.0%	35.0%
State income tax, net	2.4	2.8	4.0
Percentage depletion	0.3	(0.3)	2.2
Non-deductible compensation	(1.2)	0.7	(4.2)
Other	(0.6)	1.3	(1.0)
Effective tax rate	35.9%	39.5%	36.0%

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2015 and 2014 are presented below:

	As of December 31,	
	2015	2014
	(in thousands)	
Deferred tax assets:		
Deferred compensation	$ 13,104	$ 10,459
Asset retirement obligations	34,101	28,051
State NOL and tax credit carryforwards, net	3,376	3,761
Alternative minimum tax - credit carryforward	2,812	2,906
Settlement of class action litigation	—	12,259
Other	3,412	3,144
Deferred tax assets	56,805	60,580
Deferred tax liabilities:		
Properties and equipment	99,191	130,155
Net change in fair value of unsettled derivatives	100,369	113,007
Convertible debt	697	2,285
Total gross deferred tax liabilities	200,257	245,447
Net deferred tax liability	$ 143,452	$ 184,867

Deferred tax assets decreased in 2015, primarily due to the reclassification of the deferred tax asset associated with the settlement of certain partnership-related class action litigation to properties and equipment. The cost of the settlement of this litigation has been capitalized to the value of crude oil and natural gas properties for income tax purposes.

Deferred tax liabilities for properties and equipment decreased as a result of the increase in the deferred tax asset for the impairment of some of our crude oil and natural gas properties and the reclassification of the deferred asset for litigation settlement. Both of these deferred tax assets relate to the tax basis of our crude oil and natural gas properties and are therefore netted against the deferred tax liability. This decrease from impairments and litigation settlement was partially offset by our continued use of statutory provisions for expensing and accelerated amortization of IDCs and accelerated tax depreciation. In addition, the fair value of unsettled derivatives at December 31, 2015 decreased and resulted in a decrease to our unrealized tax gain versus a larger unrealized tax gain at December 31, 2014.

As of December 31, 2015, we have state NOL carryforwards of $74.3 million that begin to expire in 2030 and state credit carryforwards of $1.6 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, 2015. The total amount of unrecognized tax benefits that would affect the effective tax rate increased to $0.1 million in the current year due to interest recorded on a tax filing position related to our 2014 federal tax return which the IRS is in disagreement with at December 31, 2015. The statute of limitations for most of our state tax jurisdictions is open from 2011 forward.

In accordance with the CAP program, the IRS completed its “post filing review” of our 2013 tax return in January 2015 and issued a “no change” letter for the reviewed tax year. The IRS has not completed its “post filing review” of our 2014 return as one “un-agreed issue” remained at December 31, 2015. The CAP audit employs a real-time review of our books and tax records by the IRS that is intended to permit issue resolution prior to, or shortly after, the filing of the tax returns. We are currently participating in the CAP program for the review of our 2014 and 2015 tax years and we have been invited and have accepted continued participation in the program for our 2016 tax year. Participation in the CAP program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

As of December 31, 2015, we were current with our income tax filings in all applicable state jurisdictions. In 2013, the State of Colorado examined our 2008 through 2011 Colorado corporate income tax returns and proposed no adjustments.

NOTE 8 - LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31,	
	2015	2014
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$ 115,000	$ 115,000
Unamortized discount	(1,852)	(6,077)
Unamortized debt issuance costs	(208)	(765)
3.25% Convertible senior notes due 2016, net of discount and unamortized debt issuance costs	112,940	108,158
7.75% Senior notes due 2022:		
Principal amount	500,000	500,000
Unamortized debt issuance costs	(7,563)	(8,683)
7.75% Senior notes due 2022, net of unamortized debt issuance costs	492,437	491,317
Total senior notes	605,377	599,475
Revolving credit facility	37,000	56,000
Total debt, net of discount and unamortized debt issuance costs	642,377	655,475
Less current portion of long-term debt	112,940	—
Long-term debt	$ 529,437	$ 655,475

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million aggregate principal amount 3.25% convertible senior notes due 2016 (the "Convertible Notes") in a private placement to qualified institutional buyers. The maturity for the payment of principal is May 15, 2016. Interest is payable semi-annually in arrears on each May 15 and November 15. The Convertible Notes are senior, unsecured obligations and rank senior in right of payment to our existing and future indebtedness that is expressly subordinated in right of payment to the Convertible Notes; equal in right of payment to our existing and future unsecured indebtedness that is not expressly subordinated (including our 2022 Senior Notes); effectively junior in right of payment to any of our secured indebtedness (including our obligations under our revolving credit facility) 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 subsidiaries. The indenture governing the Convertible Notes contains certain non-financial covenants. The Convertible Notes and the common stock issuable upon conversion of the Convertible Notes, if any, have not been registered under the Securities Act of 1933 or any state securities laws, nor are we required to register such Convertible Notes or common shares. The Convertible Notes are governed by an indenture between the Company and the Bank of New York Mellon, as trustee.

Beginning in November 15, 2015, holders of the Convertible Notes may convert the notes at an initial conversion rate of 23.5849 shares per $1,000 principal amount, which is equal to a conversion price of approximately $42.40 per share. The conversion rate is subject to adjustment upon certain events. Upon conversion, we have elected to settle the principal amount of the Convertible Notes in cash and settle the excess conversion value in shares, as well as cash in lieu of fractional shares, in May 2016.

We allocated the gross proceeds of the Convertible Notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based on the fair value of similar debt instruments with similar terms, excluding the conversion feature, and priced on the same day we issued the Convertible Notes. The initial $20.7 million equity component represents the debt discount and was calculated as the difference between the liability component of the debt and the gross proceeds of the Convertible Notes. As of December 31, 2015, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the Convertible Notes of 0.4 years using an effective interest rate of 7.4%. For 2015, interest expense related to the indebtedness and the amortization of the discount was $3.7 million and $4.2 million, respectively, compared to $3.7 million and $3.9 million, respectively, in 2014 and $3.7 million each in 2013. As of December 31, 2015, the principal amount exceeded the "if-converted" value of the Convertible Notes by approximately $29.8 million.

7.75% Senior Notes Due 2022. In October 2012, we issued $500 million aggregate principal amount 7.75% senior notes due October 15, 2022 (the "2022 Senior Notes") in a private placement to qualified institutional buyers. 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 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 (including our Convertible Notes) 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), including borrowings under our revolving credit facility.

In connection with the issuance of the 2022 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 related to an offer to exchange the notes for substantially identical registered notes and to use commercially reasonable efforts to cause the exchange offer to be completed on or prior to September 28, 2013. The registration statement was declared effective by the SEC in July 2013 and the exchange offer was completed in August 2013.

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, and 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% 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% 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.

As of December 31, 2015, we were in compliance with all covenants related to the Convertible Notes and the 2022 Senior Notes, and expect to remain in compliance throughout the next 12-month period.

Credit Facility

Revolving Credit Facility. In September 2015, we entered into a Second Amendment to Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and other lenders party thereto. This agreement amends and restates the credit agreement dated November 2010 and extends the maturity of the revolving credit facility to May 2020. The revolving credit facility is available for working capital requirements, capital expenditures, 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. In September 2015, we completed the semi-annual redetermination of our revolving credit facility, which resulted in the reaffirmation of our borrowing base at $700 million; however, we have elected to maintain the aggregate commitment at $450 million. The borrowing base 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 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. We had an outstanding balance of $37.0 million on our revolving credit facility as of December 31, 2015 compared to $56.0 million outstanding as of December 31, 2014. 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 2.6% and 3.8% per annum as of December 31, 2015 and 2014, respectively.

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 a premium and 1-month LIBOR plus a premium), or at our election, a rate equal to the rate for dollar deposits in the London interbank market 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. No principal payments are 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 to 1.00 and (b) not exceed a maximum leverage ratio of 4.25 to 1.00. As of December 31, 2015, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period.

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 2022 Senior Notes or the Convertible Notes. Among other things, the restriction on redemption of the 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 the greater of $115 million or an amount equal to or greater than 30% of such aggregate commitment. The restriction on redemption of the 2022 Senior Notes permits redemption only with the proceeds of issuances of "Permitted Refinancing Indebtedness," which may not exceed $750 million.

As of December 31, 2015, RNG had 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 2016 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, 2015, the available funds under our revolving credit facility, including the reduction for the $11.7 million letter of credit, was $401.3 million. In addition to our currently elected commitment of $450 million, we have an additional $250 million of borrowing base availability under the revolving credit facility, subject to certain terms and conditions of the agreement.

NOTE 9 - CAPITAL LEASES

Beginning in the first quarter of 2015, we entered into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. Each lease agreement has a term of three years and is being accounted for as a capital lease, as the present value of minimum monthly lease payments, including the residual value guarantee, exceeds 90% 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, 2015:

	Amount
	(in thousands)
Vehicles	$ 1,601
Accumulated depreciation	(211)
	$ 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)
2016	$ 492
2017	492
2018	681
	1,665
Less executory cost	(70)
Less amount representing interest	(202)
Present value of minimum lease payments	$ 1,393
Short-term capital lease obligations	$ 357
Long-term capital lease obligations	1,036
	$ 1,393

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 10 - 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:

	2015	2014
	(in thousands)	
Balance at beginning of period, January 1, 2015	$ 73,855	$ 41,030
Revisions in estimated cash flows	11,658	31,945
Obligations incurred with development activities	2,373	1,170
Accretion expense	6,293	3,455
Obligations discharged with asset retirements	(4,687)	(3,745)
Balance end of period, December 31, 2015	89,492	73,855
Less current portion	(5,460)	(1,863)
Long-term portion	$ 84,032	$ 71,992

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 2015, the credit-adjusted risk-free rates used to discount our plugging and abandonment liabilities ranged from 7.6% to 8.0%. 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 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. The increase in the current portion of asset retirement obligations in 2015 is attributable to a decrease in the estimated useful life of certain vertical wells in the Wattenberg Field and 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 2014 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. The increase in estimated costs is primarily the result of various recent federal, state and local laws that regulate plugging operations and techniques. The revision in the asset retirement obligation did not have an immediate effect in the 2014 statement of operations as the increase in the revised obligation was offset by a capitalized amount, which will be depreciated over the useful lives of respective wells.

NOTE 11 - 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 $4.9 million, $3.9 million and $3.7 million for 2015, 2014 and 2013, respectively.

We provide a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain former executive officers. Expenses related to this plan are charged to general and administrative expenses and the related costs were immaterial in 2015, 2014 and 2013. As of December 31, 2015 and 2014, the liability related to this benefit was $1.3 million and $1.5 million, respectively, which was included in other liabilities on the consolidated balance sheets, with the exception of $0.3 million included in other accrued expenses as of December 31, 2015 and 2014.

We provide a supplemental health care benefit covering certain former executive officers and their spouses in accordance with each officer's employment agreement. Expenses incurred during 2015, 2014 and 2013 related to this plan were immaterial. As of December 31, 2015 and 2014, the related liability of $0.8 million and $0.7 million, respectively, is included in other liabilities on the consolidated balance sheets.

We maintain a non-qualified deferred compensation plan for our non-employee directors. The amount of compensation deferred by each participant is based on participant elections. The amounts deferred pursuant to the plan are invested in our common stock, maintained in a rabbi trust and are classified in the consolidated balance sheets as treasury shares as a component of shareholders' equity. The plan may be settled in either cash or shares as requested by the participant. The liability related to this plan, which was included in other liabilities on the consolidated balance sheets, was $0.6 million and $0.3 million as of December 31, 2015 and 2014, respectively.

NOTE 12 - 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 interest owners. We record in our financial statements only our share of costs based upon our working interest in the wells. These contracts require us to pay these transportation and processing charges, whether or not the required volumes are delivered. As natural gas prices continue to remain depressed, certain third-party producers under our Gas Marketing segment have begun and may continue to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. In 2015, we recorded an allowance for doubtful accounts of approximately \$0.5 million. We have initiated several legal actions for collection against some of the third-party producers, which have resulted in no collections and some of the third-party producers shutting-in wells.

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

	Year Ending December 31,						
Area	2016	2017	2018	2019	2020 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Gas Marketing segment	7,136	7,117	7,117	7,117	18,687	47,174	August 31, 2022
Utica Shale	2,745	2,737	2,737	2,737	9,811	20,767	July 22, 2023
Total	9,881	9,854	9,854	9,854	28,498	67,941	
Crude oil (MBbls)							
Wattenberg Field	2,420	2,413	2,413	2,413	1,205	10,864	June 30, 2020
Dollar commitment (in thousands)	\$ 17,622	\$ 17,156	\$ 16,324	\$ 16,324	\$ 17,193	\$ 84,619	

Litigation. The Company is involved in various legal proceedings that it considers normal to its business. 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. There is no assurance that settlements can be reached on acceptable terms or that adverse judgments, if any, in the remaining litigation will not exceed the amounts reserved. 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

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 principal, which was signed in December 2014 and 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 million. In March 2015, the class action was dismissed with prejudice and all class claims were released. As of December 31, 2014, the Company accrued a liability of \$37.5 million related to this litigation, which was included in other accrued expenses in the consolidated balance sheet.

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 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. As of December 31, 2015 and 2014, we had accrued environmental liabilities in the amount of \$4.1 million and \$0.8 million, respectively, included in other accrued expenses on the consolidated balance sheets. We are not aware of any environmental claims existing as of December 31, 2015 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.

In August 2015, we received a Clean Air Act Section 114 Information Request (the "Information Request") from the United States Environmental Protection Agency ("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.

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.

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.

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, 2015:

	Year Ending December 31,						
	2016	2017	2018	2019	2020	Thereafter	Total
				(in thousands)			
Minimum Lease Payments	$ 2,353	$ 2,166	$ 1,975	$ 1,937	$ 1,967	$ 124	$ 10,522

Operating lease expense for the years ended 2015, 2014 and 2013 was $9.8 million, $7.0 million and $7.0 million, respectively.

Employment Agreements with Executive Officers. Each of our senior executive officers may be entitled to a severance payment and certain other benefits upon the termination of the officer's employment pursuant to the officer's employment agreement and/or the Company's executive severance compensation plan. The nature and amount of such benefits would vary based upon, among other things, whether the termination followed a change of control of the Company.

NOTE 13 - COMMON STOCK

Sale of Equity Securities

In March 2015, we completed a public offering of 4,002,000 shares of our common stock, par value $0.01 per share, at a price to us of $50.73 per share. Net proceeds of the offering were $202.9 million, after deducting offering expenses and underwriting discounts, of which $40,020 is included in common shares-par value and $202.8 million is included in additional paid-in capital ("APIC") on the December 31, 2015 consolidated balance sheet. The shares were issued pursuant to an effective shelf registration statement on Form S-3 filed with the SEC in March 2015.

In August 2013, we completed a public offering of 5,175,000 shares of our common stock, par value $0.01 per share, at a price to us of $53.37 per share. Net proceeds of the offering were approximately $275.8 million, after deducting offering expenses and underwriting discounts, of which $51,750 is included in common shares-par value and approximately $275.8 million is included in APIC on the consolidated balance sheets. The shares were issued pursuant to an effective shelf registration statement on Form S-3 filed with the SEC in January 2012.

Stock-Based Compensation Plans

2010 Long-Term Equity Compensation Plan. In June 2010, our shareholders 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 incentive or non-qualified stock options, 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 incentive or non-qualified stock options and 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, 2015, 1,101,831 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, 2015	2014	2013
	(in thousands)		
Stock-based compensation expense	$ 20,068	$ 17,518	$ 12,880
Income tax benefit	(7,636)	(5,955)	(4,697)
Net stock-based compensation expense	$ 12,432	$ 11,563	$ 8,183

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.

In January 2015, the Compensation Committee awarded 68,274 SARs to our executive officers. 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, 2015	2014	2013
Expected term of award	5.2 years	6 years	6 years
Risk-free interest rate	1.4%	2.1%	1.0%
Expected volatility	58.0%	65.6%	65.5%
Weighted-average grant date fair value per share	$ 22.23	$ 29.96	$ 21.96

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, 2015				2014			2013		
	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,	279,011	$ 38.77	7.8	$ 1,472	190,763	$ 33.77	$ 3,711	118,832	$ 30.80	$ 486
Awarded	68,274	39.63	—	—	88,248	49.57	—	87,078	37.18	—
Exercised	(20,832)	38.05	—	473	—	—	—	(15,147)	30.06	425
Outstanding at December 31,	326,453	38.99	7.3	4,697	279,011	38.77	1,472	190,763	33.77	3,711
Exercisable at December 31,	222,489	37.70	6.8	3,489	139,334	36.27	982	51,922	29.97	1,207

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our consolidated statements of operations as of December 31, 2015, was $1.7 million. The cost is expected to be recognized over a weighted-average period of 1.4 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.

In January 2015, the Compensation Committee awarded to our executive officers a total of 80,707 time-based restricted shares that vest ratably over a three-year period ending on January 16, 2018.

The following table presents the changes in non-vested time-based awards during 2015:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2014	564,332	$ 46.02
Granted	313,639	48.88
Vested	(333,167)	41.59
Forfeited	(19,723)	54.29
Non-vested at December 31, 2015	525,081	50.23

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,		
	2015	2014	2013
	(in thousands, except per share data)		
Total intrinsic value of time-based awards vested	$ 17,077	$ 18,278	$ 13,640
Total intrinsic value of time-based awards non-vested	28,029	23,290	34,688
Market price per common share as of December 31,	53.38	41.27	53.22
Weighted-average grant date fair value per share	48.88	56.45	45.53

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our consolidated statements of operations as of December 31, 2015 was $16.4 million. This cost is expected to be recognized over a weighted-average period of 1.7 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 2015, the Compensation Committee awarded a total of 29,398 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 shareholder 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, 2017 and can result in a payout between 0% and 200% of the total shares awarded. 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,	
	2015	2014
Expected term of award	3 years	3 years
Risk-free interest rate	0.9%	0.8%
Expected volatility	53.0%	55.2%
Weighted-average grant date fair value per share	$ 66.16	$ 56.87

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.

The following table presents the change in non-vested market-based awards during 2015:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2014	83,721	$ 52.98
Granted	29,398	66.16
Vested	(41,570)	49.04
Non-vested at December 31, 2015	71,549	63.60

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,		
	2015	2014	2013
	(in thousands, except per share data)		
Total intrinsic value of market-based awards vested	$ 4,293	$ 1,260	$ 724
Total intrinsic value of market-based awards non-vested	3,819	3,455	3,838
Market price per common share as of December 31,	53.38	41.27	53.22
Weighted-average grant date fair value per share	66.16	56.87	49.04

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our consolidated statements of operations as of December 31, 2015 was $1.9 million. This cost is expected to be recognized over a weighted-average period of 1.4 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 to service awards. For shares reissued to service awards 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. During the year ended December 31, 2015, we acquired 136,168 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 127,159 shares were reissued and 9,009 shares are available for reissuance pursuant to our 2010 Plan.

Shareholders' Rights Agreement

In 2007, we entered into a rights agreement. The rights agreement is designed to improve the ability of our Board to protect the interest of our shareholders in the event of an unsolicited takeover attempt. Our Board declared a dividend of one right for each outstanding share of our common stock. The right dividend was paid to shareholders of record in September 2007. A "distribution date," as defined in the rights agreement, can occur after any individual shareholder exceeds 15% ownership of our outstanding common stock. In certain circumstances, the right entitles each holder, other than an "acquiring person" (as defined in the agreement), to purchase shares of our common stock (or, in certain circumstances, cash, property or other securities) having a then-current value equal to two times the exercise price of the right (i.e., for the $240 exercise price, the rights holder receives $480 worth of common stock). The exercise price is subject to adjustment for various corporate actions which affect all shareholders, such as a stock split. The rights agreement and all rights will expire in September 2017.

Preferred stock

We are authorized, pursuant to shareholder 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, 2015, no preferred shares had been issued.

NOTE 14 - 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,		
	2015	2014	2013
		(in thousands)	
Weighted-average common shares outstanding - basic	39,153	35,784	32,426
Dilutive effect of:			
Restricted stock	—	279	—
Convertible notes	—	564	—
Other equity-based awards	—	51	—
Weighted-average common shares and equivalents outstanding - diluted	39,153	36,678	32,426

For 2015 and 2013, 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,		
	2015	2014	2013
		(in thousands)	
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
Restricted stock	831	8	823
Convertible notes	562	—	518
Other equity-based awards	101	26	83
Total anti-dilutive common share equivalents	1,494	34	1,424

In November 2010, we issued our 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 Convertible Notes could be included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeds 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 years ended December 31, 2015 and 2013, respectively, as the effect would be anti-dilutive to our earnings per share. Shares issuable upon conversion of the 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 15 - ASSETS HELD FOR SALE, DIVESTITURES AND DISCONTINUED OPERATIONS

In October 2014, we completed the sale of our entire 50% 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. Proceeds from the divestiture were used to reduce outstanding borrowings on our revolving credit facility and to fund a portion of our 2014 capital budget. As the divestiture represents a strategic shift that will have a major effect on our operations as our organization structure will no longer have 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 all periods presented.

The tables below set forth selected financial information related to net assets divested and operating results related to discontinued operations. Net assets held for sale represents the assets that are expected to be sold. While the reclassification of revenues and expenses related to discontinued operations for prior periods had no impact upon previously reported net earnings, the consolidated statements of operations table presents the revenues and expenses that were reclassified from the specified consolidated statements of operations line items 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	2013
	(in thousands)	
Revenues		
Crude oil, natural gas and NGLs sales	$ 24,149	$ 39,001
Sales from natural gas marketing	—	2,825
Commodity price risk management income (loss), net	(1,085)	14
Well operations, pipeline income and other	48	922
Total revenues	23,112	42,762
Costs, expenses and other		
Lease operating expenses	1,280	6,522
Production taxes	1,579	3,716
Transportation, gathering and processing expenses	3,536	5,283
Cost of natural gas marketing	—	2,673
Impairment of crude oil and natural gas properties	433	954
Depreciation, depletion and amortization	9,128	13,894
Other	4,170	8,235
Gain on sale of properties and equipment	(76,479)	1,700
Total costs, expenses and other	(56,353)	42,977
Interest expense	(2,222)	(1,755)
Interest income	194	10
Income from discontinued operations	77,437	(1,960)
Provision for income taxes	(29,263)	770
Income (loss) from discontinued operations, net of tax	$ 48,174	$ (1,190)

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

Supplemental cash flows information - discontinued operations	Year Ended December 31, 2014	2013
	(in thousands)	
Cash flows from investing activities:		
Capital expenditures	$ (17,253)	$ (45,277)
Significant non-cash investing items:		
Change in accounts payable related to purchases of properties and equipment	(5,727)	(4,738)

Assets held for sale of $2.9 million as of December 31, 2015 and 2014 represents the carrying value of approximately 12 acres of land located adjacent to our Bridgeport, West Virginia, regional headquarters.

NOTE 16 - TRANSACTIONS WITH AFFILIATES

PDCM and Affiliated Partnerships. Our Gas Marketing segment marketed the natural gas produced by our affiliated partnerships and, until the fourth quarter of 2014, by PDCM. Our cost of natural gas marketing includes $1.3 million in 2013 related to the marketing of natural gas on behalf of our affiliated partnerships and $23.2 million and $18.1 million in 2014 and 2013, respectively, related to the marketing of natural gas on behalf of PDCM.

Prior to October 2014, amounts due from/to affiliates included amounts billed for certain well operating and administrative services provided to PDCM. Amounts billed to PDCM for these services were $5.7 million and $14.5 million in 2014 and 2013, respectively. Our consolidated statements of operations include only our proportionate share of these billings. All amounts billed to PDCM for operating and administrative services in 2014 have been collected. Accordingly, we had no amounts due from PDCM as of December 31, 2014.

NOTE 17 - 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 well operation and pipeline income. Segment income (loss) consists of segment revenue less production cost, exploration expense, impairment of crude oil and natural gas properties, direct general and administrative expense and DD&A expense. Segment DD&A expense was $298.8 million, $188.5 million and $111.6 million in 2015, 2014 and 2013, respectively.

Gas Marketing. Our Gas Marketing segment purchases, aggregates and resells natural gas produced by us and others. Segment income (loss) primarily represents sales from natural gas marketing and direct interest income less costs of natural 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:

	2015	2014	2013
		(in thousands)	
Year Ended December 31,			
Segment revenues:			
Oil and gas exploration and production	$ 584,406	$ 784,636	$ 322,878
Gas marketing	10,920	71,571	69,787
Total revenues	$ 595,326	$ 856,207	$ 392,665
Segment income (loss) before income taxes:			
Oil and gas exploration and production	$ 31,429	$ 344,149	$ 81,913
Gas marketing	(797)	(445)	(297)
Unallocated	(137,220)	(166,476)	(114,579)
Income (loss) before income taxes	$ (106,588)	$ 177,228	$ (32,963)
Expenditures for segment long-lived assets:			
Oil and gas exploration and production	$ 599,617	$ 623,912	$ 403,227
Unallocated	5,051	4,680	1,379
Total	$ 604,668	$ 628,592	$ 404,606
As of December 31,			
Segment assets:			
Oil and gas exploration and production	$ 2,294,288	$ 2,258,060	
Gas marketing	4,217	6,979	
Unallocated	69,164	63,227	
Assets held for sale	2,874	2,874	
Total assets	$ 2,370,543	$ 2,331,140	

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, 2015, 2014 and 2013, all of our estimates of proved reserves were based on reserve reports prepared by Ryder Scott Company, L.P. 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 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)*
2015	$ 42.10	$ 2.05	$ 12.23
2014	84.65	3.92	32.27
2013	82.18	3.22	29.92

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

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, 2013 (1)	59,310	604,038	32,827	192,810
Revisions of previous estimates	(18,420)	(117,068)	(8,549)	(46,480)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	55,759	365,563	25,249	141,935
Purchases of reserves	343	2,894	217	1,043
Dispositions	(252)	(94,927)	(30)	(16,104)
Production	(2,910)	(20,860)	(1,043)	(7,430)
Proved reserves, December 31, 2013 (2)	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
Purchases 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
Purchases 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
Proved Developed Reserves, as of:				
January 1, 2013 (1)	20,412	281,925	14,353	81,753
December 31, 2013 (2)	23,997	220,387	14,825	75,553
December 31, 2014	26,798	186,633	17,002	74,905
December 31, 2015	26,257	175,367	15,011	70,496
Proved Undeveloped Reserves, as of:				
January 1, 2013 (1)	38,898	322,113	18,474	111,058
December 31, 2013 (2)	69,833	519,253	33,846	190,221
December 31, 2014	73,717	350,339	43,117	175,224
December 31, 2015	72,718	485,370	48,716	202,329

(1) *Includes estimated reserve data related to our Piceance and NECO assets, which were divested in June 2013. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, for additional details related to the divestiture of our Piceance and NECO assets. Total proved reserves include 148 MBbls of crude oil and 83,656 MMcf of natural gas, for an aggregate of 14,091 MBoe of crude oil equivalent related to our Piceance and NECO assets. There were no proved undeveloped reserves attributable to the Piceance and NECO assets as of December 31, 2012.*

(2) *Includes estimated reserve data related to our Marcellus Shale assets, which were divested in October 2014. See Note 15, Assets Held for Sale, Divestitures and Discontinued Operations, for additional details related to the divestiture of our Marcellus Shale assets. Total proved reserves included 235,950 MMcf of natural gas, for an aggregate of 39,325 Mboe of crude oil equivalent, related to our Marcellus Shale assets. Total proved developed reserves related to those assets included 53,904 MMcf and 8,984 MBoe, respectively, and proved undeveloped reserves included 182,046 MMcf and 30,341 MBoe, respectively.*

	Developed	Undeveloped	Total
		(MBoe)	
Beginning proved reserves, January 1, 2013	81,753	111,057	192,810
Production	(7,430)	—	(7,430)
Undeveloped reserves converted to developed	3,212	(3,212)	—
Purchases of reserves	1,043	—	1,043
Dispositions	(16,104)	—	(16,104)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	19,830	122,105	141,935
Revisions of previous estimates	(6,751)	(39,729)	(46,480)
Ending proved reserves, December 31, 2013	75,553	190,221	265,774
Production	(9,294)	—	(9,294)
Undeveloped reserves converted to developed	12,730	(12,730)	—
Purchases of reserves	17	—	17
Dispositions	(9,231)	(30,341)	(39,572)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	27,957	70,072	98,029
Revisions of previous estimates	(22,827)	(41,998)	(64,825)
Ending proved reserves, December 31, 2014	74,905	175,224	250,129
Production	(15,369)	—	(15,369)
Undeveloped reserves converted to developed	29,090	(29,090)	—
Purchases of reserves	76	—	76
Dispositions	(34)	—	(34)
Extensions, discoveries and other additions, including infill reserves in an existing proved field	8,703	122,791	131,494
Revisions of previous estimates	(26,875)	(66,596)	(93,471)
Ending proved reserves, December 31, 2015	70,496	202,329	272,825

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 MMBoe. At December 31, 2014, we projected a PUD conversion rate of 16% for 2015. Our actual conversion rate was 17%, 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 proven 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%. 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 7% for 2014. Our actual conversion rate was 7%, 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.

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.

2013 Activity. Overall, our proved reserves increased by 73 MMBoe as of December 31, 2013 as compared to December 31, 2012. In 2013, we produced 7.4 MMBoe. At December 31, 2012, we projected a PUD conversion rate of 15% to 20% for 2013. Our actual conversion rate was 3%, resulting in 3 MMBoe of reserves booked as PUDs at December 31, 2012 being converted to proved developed reserves during 2013. As shown, we acquired 1 MMBoe of proved reserves in 2013. We divested a total of 16 MMBoe in 2013, primarily related to the sales of our Piceance Basin, NECO and shallow Upper Devonian (non-Marcellus Shale) assets.

Extensions, discoveries and other additions, including infill reserves, of approximately 142 MMBoe were added in 2013, approximately 110 MMBoe, 18 MMBoe and 14 MMBoe of which were added to the Wattenberg Field, Marcellus Shale and Utica Shale, respectively. Approximately 125 MMBoe of new proved undeveloped reserves were booked, including 32 MMBoe due to adjustments in well spacing in the Wattenberg Field and Marcellus Shale. In addition, approximately 17 MMBoe of previously unbooked locations were developed in the current year.

We recorded a downward revision of our previous estimate of proved reserves of approximately 46 MMBoe. The revision was primarily due to a decrease of approximately 55 MMBoe, of which approximately 32 MMBoe is due to increased well density plans in the Wattenberg Field, which delayed the expected development date for many existing PUD locations beyond the limits of the SEC five-year rule, approximately 9 MMBoe is due to expired leases, approximately 11 MMBoe is due to our shift from vertical to horizontal drilling in the Wattenberg Field and approximately 3 MMBoe is to remove Wattenberg Field PUDs that were no longer in our core drilling area. These decreases were partially offset by various factors, including but not limited to interest adjustments, well performance and changing economics.

Based on the economic conditions on December 31, 2013, 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 2013 drilling program focused on locations that were not included in proved undeveloped reserves in the December 31, 2012 reserve report due to increased well density testing in the Wattenberg Field. The success of this increased well density testing allowed us to add considerable PUD reserves in the 2013 reserve report.

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 natural gas marketing and well operations and pipeline services.

	Year Ended December 31, 2015	2014	2013
		(in thousands)	
Revenue:			
Crude oil, natural gas and NGLs sales	$ 378,713	$ 495,562	$ 379,796
Commodity price risk management gain (loss), net	203,183	309,219	(23,905)
	581,896	804,781	355,891
Expenses:			
Lease operating expenses	56,992	43,682	40,339
Production taxes	18,443	27,194	25,474
Transportation, gathering and processing expenses	10,151	8,128	10,435
Exploration expense	1,102	948	7,071
Impairment of proved crude oil and natural gas properties	161,620	167,280	53,827
Depreciation, depletion, and amortization	298,760	201,656	124,202
Accretion of asset retirement obligations	6,293	3,455	4,747
(Gain) loss on sale of properties and equipment	(385)	(75,972)	3,722
	552,976	376,371	269,817
Results of operations for crude oil and natural gas producing activities before provision for income taxes	28,920	428,410	86,074
Provision for income taxes	(10,394)	(166,930)	(31,109)
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$ 18,526	$ 261,480	$ 54,965

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.

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, 2015	2014	2013
		(in thousands)	
Acquisition of properties: (1)			
Proved properties	$ 3,561	$ 11,973	$ 28,698
Unproved properties	15	45,999	3,390
Development costs (2)	552,104	608,176	338,294
Exploration costs: (3)			
Exploratory drilling	—	—	58,988
Geological and geophysical	—	1	752
Total costs incurred	$ 555,680	$ 666,149	$ 430,122

(1) Property acquisition costs represent costs incurred to purchase, lease or otherwise acquire a property.
(2) 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, 2015, 2014 and 2013, $207.8 million, $125.2 million and $40.1 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end.
(3) 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,	
	2015	2014
	(in thousands)	
Proved crude oil and natural gas properties	$ 2,881,189	$ 2,267,165
Unproved crude oil and natural gas properties	60,498	188,206
Uncompleted wells, equipment and facilities	109,385	164,402
Capitalized costs	3,051,072	2,619,773
Less accumulated DD&A	(1,131,705)	(808,431)
Capitalized costs, net	$ 1,919,367	$ 1,811,342

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 obligation. 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.

	As of December 31,		
	2015	2014	2013
	(in thousands)		
Future estimated cash flows	$ 6,297,298	$ 12,550,515	$ 11,550,917
Future estimated production costs*	(1,577,393)	(2,816,776)	(2,329,836)
Future estimated development costs	(1,952,332)	(2,458,790)	(2,778,148)
Future estimated income tax expense	(508,332)	(2,336,510)	(2,119,615)
Future net cash flows	2,259,241	4,938,439	4,323,318
10% annual discount for estimated timing of cash flows	(1,162,377)	(2,631,974)	(2,541,155)
Standardized measure of discounted future estimated net cash flows	$ 1,096,864	$ 2,306,465	$ 1,782,163

* Represents future estimated lease operating expenses, production taxes, transportation, gathering and processing expenses and plugging and abandonment costs, net of salvage value.

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

	Year Ended December 31, 2015	2014	2013
		(in thousands)	
Sales of crude oil, natural gas and NGLs production, net of production costs	$ (293,127)	$ (387,789)	$ (286,021)
Net changes in prices and production costs (1)	(1,752,921)	129,213	89,527
Extensions, discoveries, and improved recovery, including infill reserves in an existing proved field, less related costs (2)	489,178	1,444,581	1,529,006
Sales of reserves (3)	(463)	(402,595)	(142,724)
Purchases of reserves (4)	374	238	10,610
Development costs incurred during the period	368,840	161,404	46,366
Revisions of previous quantity estimates (5)	(1,286,462)	(654,318)	(397,738)
Changes in estimated income taxes (6)	902,994	(221,874)	(381,369)
Net changes in future development costs	112,958	46,499	(40,707)
Accretion of discount	345,007	270,389	142,040
Timing and other	(95,979)	138,554	44,676
Total	$ (1,209,601)	$ 524,302	$ 613,666

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(1) Our weighted-average price, net of production costs per Boe, in our 2015 reserve report decreased to $17.30 as compared to $37.78 in our 2014 reserve report. This is due to the significant decrease in SEC commodity prices utilized in the 2015 reserve report. Our weighted-average price, net of production costs per Boe, in our 2014 reserve report increased to $37.78 from $30.82 in our 2013 reserve report. This is due to the divestiture of our Marcellus Shale reserves during 2014 which further increased our liquids as a percentage of proved reserves.

(2) The 66% decrease in 2015 indicates a significant decrease in the value of the extensions in 2015 as compared to the value of the extensions in 2014. This is primarily due to lower SEC commodity prices utilized in the 2015 reserve report. The 6% decrease in 2014 as compared to 2013 is primarily due to a scheduled maximum rig count of six rigs by 2016 as compared to a scheduled maximum rig count of seven in the 2013 year-end reserve report, partially offset by our increased PUD count in the Wattenberg Field resulting from successful downspacing tests in 2014.

(3) The decrease in sales of reserves in 2015 was due to the fact that no major divestitures were completed in 2015. The increase in sales of reserves in 2014 as compared to 2013 was due to the divestiture of our Marcellus shale assets in October 2014.

(4) The decrease in purchases of reserves in 2015 and 2014 as compared to the respective prior years was due to no material acquisitions having occurred.

(5) The change in revisions of our previous quantity estimates in 2015 as compared to 2014 was primarily due to adjustments due to our drilling schedule. The change in revisions of our previous quantity estimates in 2014 as compared to 2013 was primarily due to adjustments due to our drilling schedule.

(6) The change in estimated income taxes for each year as compared to the prior year is the direct result of the significant changes in discounted future net cash flows, as the projected deferred tax rate remained relatively unchanged at approximately 38% for each of the three years ended December 31, 2015, 2014 and 2013. In addition, the Company continued to capitalize and amortize the majority of its yearly capital expenditures and there were no changes in the assumptions as to the tax deductibility of beginning unamortized capital, additional current year capital or future development capital. Further, future tax deductions for capital expenditures were not affected by the impairment of crude oil and natural gas properties in 2014 and 2015 as such impairments are not tax deductible.

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, 2015 and 2014 is presented below. The quarterly consolidated statements of operations below reflect our revised presentation. See Note 1, *Nature of Operations and Basis of 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.

	2015				
	Quarter Ended				
	March 31	June 30	September 30	December 31	Year Ended
	(in thousands, except per share data)				
Revenues:					
Crude oil, natural gas and NGLs sales	$ 74,109	$ 96,928	$ 104,483	$ 103,193	$ 378,713
Sales from natural gas marketing	3,233	2,523	2,580	2,584	10,920
Commodity price risk management gain (loss), net	66,662	(49,041)	123,549	62,013	203,183
Well operations, pipeline income and other	628	550	488	844	2,510
Total revenues	144,632	50,960	231,100	168,634	595,326
Costs, expenses and other:					
Lease operating expenses	16,285	12,639	13,824	14,244	56,992
Production taxes	3,893	3,837	5,476	5,237	18,443
Transportation, gathering and processing expenses	1,338	1,308	3,938	3,567	10,151
Cost of natural gas marketing	3,258	2,836	2,781	2,842	11,717
Exploration expense	285	275	252	290	1,102
Impairment of crude oil and natural gas properties	2,772	4,404	154,031	413	161,620
General and administrative expense	21,045	20,728	20,278	27,908	89,959
Depreciation, depletion and amortization	55,820	70,106	80,947	96,385	303,258
Accretion of asset retirement obligations	1,560	1,588	1,594	1,551	6,293
(Gain) loss on sale of properties and equipment	(21)	(207)	(74)	(83)	(385)
Total costs, expenses and other	106,235	117,514	283,047	152,354	659,150
Income (loss) from operations	38,397	(66,554)	(51,947)	16,280	(63,824)
Interest expense	(11,725)	(11,567)	(12,092)	(12,187)	(47,571)
Interest income	1,113	1,135	1,378	1,181	4,807
Income (loss) from continuing operations before income taxes	27,785	(76,986)	(62,661)	5,274	(106,588)
Provision for income taxes	(10,723)	30,116	21,167	(2,252)	38,308
Income (loss) from continuing operations	17,062	(46,870)	(41,494)	3,022	(68,280)
Income (loss) from discontinued operations, net of tax	—	—	—	—	—
Net income (loss)	$ 17,062	$ (46,870)	$ (41,494)	$ 3,022	$ (68,280)
Earnings per share:					
Basic					
Income (loss) from continuing operations	$ 0.47	$ (1.17)	$ (1.04)	$ 0.08	$ (1.74)
Income (loss) from discontinued operations	—	—	—	—	—
Net income (loss)	$ 0.47	$ (1.17)	$ (1.04)	$ 0.08	$ (1.74)
Diluted					
Income (loss) from continuing operations	$ 0.46	$ (1.17)	$ (1.04)	$ 0.07	$ (1.74)
Income (loss) from discontinued operations	—	—	—	—	—
Net income (loss)	$ 0.46	$ (1.17)	$ (1.04)	$ 0.07	$ (1.74)
Weighted-average common shares outstanding:					
Basic	36,349	40,035	40,085	40,094	39,153
Diluted	36,981	40,035	40,085	41,264	39,153

	2014				
	Quarter Ended				
	March 31	June 30	September 30	December 31	Year Ended
	(in thousands, except per share data)				
Revenues:					
Crude oil, natural gas and NGLs sales	$ 120,013	$ 131,017	$ 120,526	$ 99,857	$ 471,413
Sales from natural gas marketing	26,937	22,415	13,297	8,922	71,571
Commodity price risk management gain (loss), net	(24,909)	(52,643)	90,213	297,643	310,304
Well operations, pipeline income and other	616	514	520	1,269	2,919
Total revenues	122,657	101,303	224,556	407,691	856,207
Costs, expenses and other:					
Lease operating expenses	8,371	11,961	11,020	11,050	42,402
Production taxes	6,390	7,551	8,724	2,950	25,615
Transportation, gathering and processing expenses	1,235	818	1,208	1,331	4,592
Cost of natural gas marketing	26,870	22,428	13,347	9,370	72,015
Exploration expense	307	276	190	174	947
Impairment of crude oil and natural gas properties	952	2,019	1,962	161,914	166,847
General and administrative expense	24,529	41,713	36,328	20,989	123,559
Depreciation, depletion and amortization	42,889	49,636	49,640	50,363	192,528
Accretion of asset retirement obligations	841	840	861	873	3,415
(Gain) loss on sale of properties and equipment	579	(23)	21	(70)	507
Total costs, expenses and other	112,963	137,219	123,301	258,944	632,427
Income (loss) from operations	9,694	(35,916)	101,255	148,747	223,780
Interest expense	(12,183)	(12,195)	(11,821)	(11,643)	(47,842)
Interest income	187	83	39	981	1,290
Income (loss) from continuing operations before income taxes	(2,302)	(48,028)	89,473	138,085	177,228
Provision for income taxes	894	18,650	(35,396)	(54,115)	(69,967)
Income (loss) from continuing operations	(1,408)	(29,378)	54,077	83,970	107,261
Income (loss) from discontinued operations, net of tax	(719)	1,191	(80)	47,782	48,174
Net income (loss)	$ (2,127)	$ (28,187)	$ 53,997	$ 131,752	$ 155,435
Earnings per share:					
Basic					
Income (loss) from continuing operations	$ (0.04)	$ (0.82)	$ 1.51	$ 2.34	$ 3.00
Income (loss) from discontinued operations	(0.02)	0.03	—	1.33	1.34
Net income (loss) attributable to shareholders	$ (0.06)	$ (0.79)	$ 1.51	$ 3.67	$ 4.34
Diluted					
Income (loss) from continuing operations	$ (0.04)	$ (0.82)	$ 1.47	$ 2.32	$ 2.93
Income (loss) from discontinued operations	(0.02)	0.03	—	1.32	1.31
Net income (loss) attributable to shareholders	$ (0.06)	$ (0.79)	$ 1.47	$ 3.64	$ 4.24
Weighted-average common shares outstanding					
Basic	35,690	35,762	35,834	35,847	35,784
Diluted	35,690	35,762	36,828	36,146	36,678

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)		
2015:				
Allowance for doubtful accounts	$ 486	$ 1,700	$ 177	$ 2,009
Valuation allowance for unproved crude oil and natural gas properties	9,293	7,012	16,161	144
2014:				
Allowance for doubtful accounts	896	78	488	486
Valuation allowance for unproved crude oil and natural gas properties	5,142	4,465	314	9,293
2013:				
Allowance for doubtful accounts	718	322	144	896
Valuation allowance for unproved crude oil and natural gas properties	5,690	3,038	3,586	5,142

(1) *For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For valuation allowance for 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, 2015, 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, 2015.

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.

Management has assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2015, 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, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, 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 2015, 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 2016 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 2016 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 2016 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 2016 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 2016 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.

Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
2.1	Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc. (the "Company").	8-K12B	001-37419	2.1	6/8/2015	
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	Rights Agreement by and between the Company and Transfer Online, Inc., as Rights Agent, dated as of September 11, 2007, including the forms of Rights Certificates and Summary of Stockholder Rights Plan attached thereto as Exhibits A and B.	8-K	000-07246	4.1	9/17/2007	
4.2	Indenture, dated November 23, 2010, between the Company and The Bank of New York Mellon, including the form of 3.25% Convertible Senior Note due 2016.	8-K	000-07246	4.1	11/24/2010	
4.3	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	
4.4	Form of Common Stock Certificate of the Company.	8-K12B	001-37419	4.1	6/8/2015	
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 1, 2015.	10-K	000-07246	10.2	2/19/2015	
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.					X
10.6*	Executive Severance Compensation Plan, as amended.					X
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	
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					X
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	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
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.					X
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	
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
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
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 22, 2016

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 22, 2016
/s/ Gysle R. Shellum Gysle R. Shellum	Chief Financial Officer (principal financial officer)	February 22, 2016
/s/ R. Scott Meyers R. Scott Meyers	Chief Accounting Officer (principal accounting officer)	February 22, 2016
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Chairman and Director	February 22, 2016
/s/ Joseph E. Casabona Joseph E. Casabona	Director	February 22, 2016
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 22, 2016
/s/ Larry F. Mazza Larry F. Mazza	Director	February 22, 2016
/s/ David C. Parke David C. Parke	Director	February 22, 2016
/s/ James M. Trimble James M. Trimble	Director	February 22, 2016
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	February 22, 2016

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.
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:

Behind-pipe reserves - Crude oil and natural gas reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production. Generally, these are reserves in reservoirs above currently producing zones.

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.

Crude oil well - A well whose reserves are expected to produce less than 15 Mcf of gas per barrel of crude oil.

Delineation - A drilling technique carried out to gain a better understanding of the structure and extent of a deposit in order to decide whether or not to conduct further drilling activities.

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% 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 wet 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. References to net production include our proportionate share of PDCM's and our affiliated partnerships' net production.

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%. 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.

Refracture - A refracture occurs when we stimulate a well by fracturing a producing zone to increase its production as well as its PDP reserves.

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%. 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.

Unconventional resource(s) - Crude oil and natural gas that cannot be produced at economic flow rates in economic volumes unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the resources to the wellbore.

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.

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.

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SENIOR MANAGEMENT TEAM

Barton R. Brookman
President and Chief Executive Officer

Gysle R. Shellum
Chief Financial Officer

Lance A. Lauck
Executive Vice President Corporate Development and Strategy

Daniel W. Amidon
Senior Vice President General Counsel and Secretary

Scott J. Reasoner
Senior Vice President Operations

BOARD OF DIRECTORS

Jeffrey C. Swoveland
Chairman of the Board

Barton R. Brookman

Joseph E. Casabona

Anthony J. Crisafio

Larry F. Mazza

David C. Parke

James M. Trimble

Kimberly Luff Wakim

CORPORATE HEADQUARTERS

PDC Energy, Inc.
1775 Sherman Street
Suite 3000
Denver, Colorado 80203-4341
303.860.5800
www.pdce.com

REGIONAL HEADQUARTERS

PDC Energy, Inc.
120 Genesis Boulevard
Bridgeport, West Virginia 26330-9665
304.842.3597

STOCK EXCHANGE LISTING

NASDAQ: PDCE

2016 ANNUAL MEETING OF STOCKHOLDERS

The Annual Meeting of Stockholders will be held June 9, 2016, beginning at 1:00 p.m. MT. The meeting will be held at Denver Financial Center at 1775 Sherman St., Denver, Colorado 80203.

INDEPENDENT RESERVE ENGINEERS

Ryder Scott Company, L.P. Houston, Texas

INDEPENDENT AUDITORS

PricewaterhouseCoopers LLP, Pittsburgh, Pennsylvania

FORM 10-K

Additional copies of the PDC Energy, Inc. ("the Company") Annual Report on Form 10-K for the year ended December 31, 2015, as filed with the U.S. Securities and Exchange Commission ("SEC"), may be obtained free of charge by writing to the Company's corporate headquarters, Attention: Corporate Secretary.

Copies are also available electronically on the Company's website, www.pdce.com. While we recommend you view our website, the information available on our website is not part of this report and is not incorporated by reference.

SHAREHOLDER SERVICES

Computershare Investor Services
P.O. Box 30170
College Station, Texas 77842-3170
800.736.3001
www.us.computershare.com/investor

Contact Computershare for information regarding change of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

CODE OF BUSINESS CONDUCT AND ETHICS

The Code of Business Conduct and Ethics of PDC Energy is available on its website at www.pdce.com, or a copy may be obtained by writing to the Company's corporate headquarters, Attention: Corporate Secretary.

FORWARD-LOOKING STATEMENTS

The information provided in this annual report contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements are based on management's current expectations and beliefs, as well as a number of assumptions concerning future events. These statements are based on certain assumptions and analyses made by management of the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with management's expectations and predictions is subject to a number of risks and uncertainties, general economic, market or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by the Company; changes in laws or regulations; and other factors, many of which are beyond the control of the Company. You are cautioned not to put undue reliance on such forward-looking statements because actual results may vary materially from those expressed or implied, as more fully discussed in the safe harbor statements found in the Company's SEC filings, including, without limitation, the discussion under the heading "Note Regarding Forward-Looking Statements" and "Risk Factors" and elsewhere in the Company's most recent annual report on Form 10-K and in subsequent Form 10-Qs. **All forward-looking statements are based on information available to management on this date and the Company assumes no obligation to, and expressly disclaims any obligation to, update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.**

The Company has a Code of Business Conduct and Ethics (the "Code of Conduct") that applies to all Directors, officers, employees, agents, consultants and representatives of the Company, which is reviewed at least annually by the Nominating and Governance Committee. The Company's principal executive officer, principal financial officer and principal accounting officer are subject to additional specific provisions under the Code of Conduct. The Code of Conduct can be viewed on the Company's website at www.pdce.com. In the event the Board approves an amendment to or a waiver of any provisions of the Code of Conduct, the Company will disclose the information on its website.

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PDC ENERGY

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