2014 ANNUAL REPORT

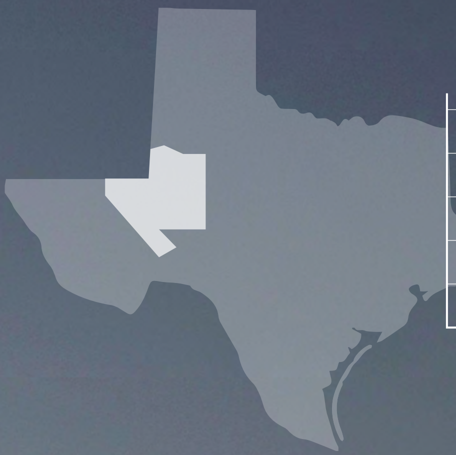
COMMITTED TO THE CORE

PARSLEY ENERGY

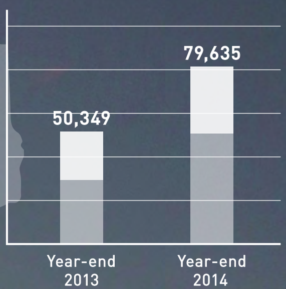
PARSLEY ENERGY

Founded in 2008, Parsley Energy is an independent oil and natural gas company with operations in the Permian Basin, where we develop unconventional oil and natural gas reserves. As we efficiently and responsibly grow reserves, production, and cash flow by developing our liquids-rich resource base, we seek to create value for shareholders, employees, energy consumers, and the communities in which we work.

Over the past several years we have demonstrated a peer-leading growth profile and have expanded from a two-person start-up to a large scale Permian Basin pure play operator with several hundred wells producing more than 18,000 barrels of oil equivalent per day (net) at year-end 2014. With a substantial inventory of horizontal and vertical drilling locations in the prolific core of the Midland Basin, we look forward to continued growth at superior rates of return.



CORE AND TIER 1 ACREAGE GROWTH

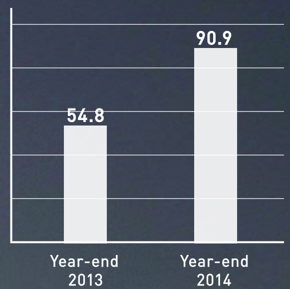


58% GROWTH

CORE TIER 1

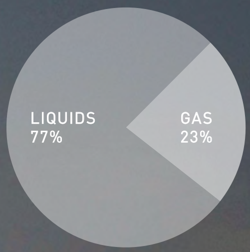
- Permian Basin pure play with a total of 136,347 net surface acres and 370,808 net effective acres, which include the Spraberry, Wolfcamp A, B, and C, Cline and Atoka intervals
- Of Parsley's 49,000+ net acres in the Core area, approximately 98% are located in our Focus Area
- Acquisitions completed in 2014 increased Parsley's Midland Basin Core and Tier 1 acreage by 58%
- Parsley now has 1,800+ horizontal drilling locations in the heart of the Midland Basin

PROVED RESERVES (MMBoe)



66% GROWTH

PROVED RESERVES ALLOCATION

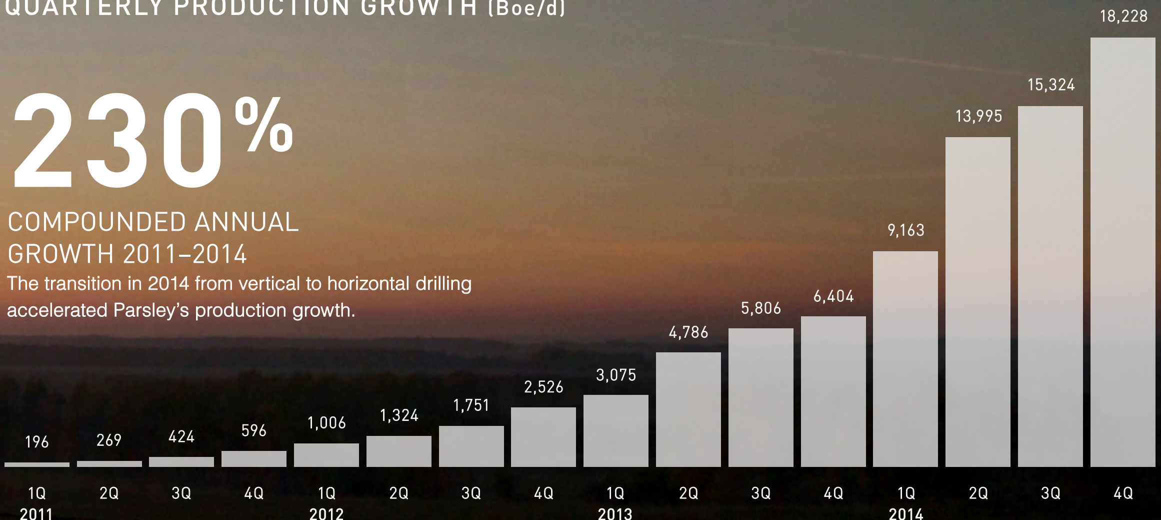


QUARTERLY PRODUCTION GROWTH (Boe/d)

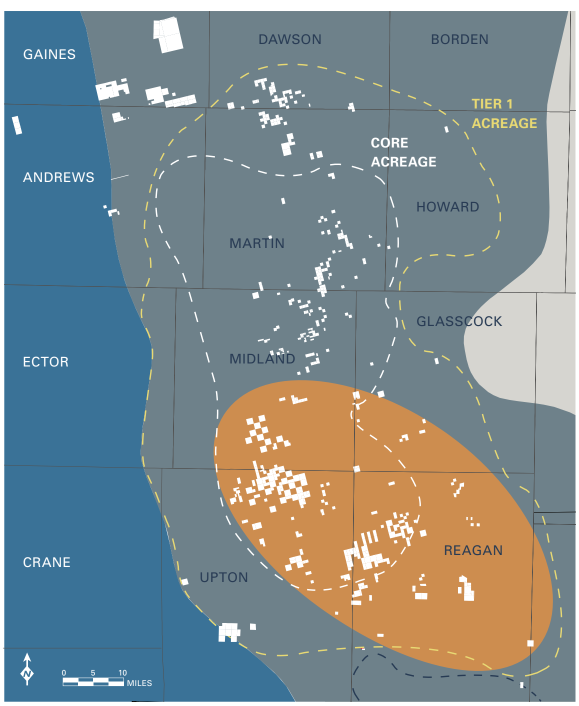
230%

COMPOUNDED ANNUAL GROWTH 2011–2014

The transition in 2014 from vertical to horizontal drilling accelerated Parsley's production growth.



PARSLEY RINGS THE CLOSING BELL AT THE NYSE ON DECEMBER 12, 2014 TO CELEBRATE THE COMPANY'S IPO.



MIDLAND BASIN ACREAGE

PARSLEY ACREAGE
CENTRAL BASIN PLATFORM
MIDLAND BASIN
FOCUS AREA

TO OUR STOCKHOLDERS:

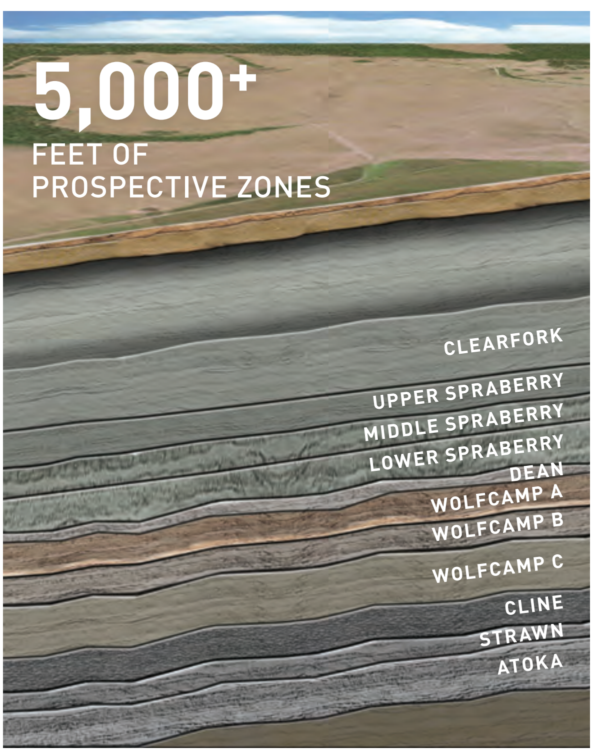
In 2014, Parsley Energy executed on our promise to deliver value from our first-class asset base in the core of the Midland Basin. We raised approximately $870 million of net proceeds in May through the second-largest IPO ever by an E&P company, and we put that capital to work for investors, nearly tripling our production, more than doubling our proved developed reserves, and adding meaningfully to our core acreage position and our inventory of future horizontal drilling locations.

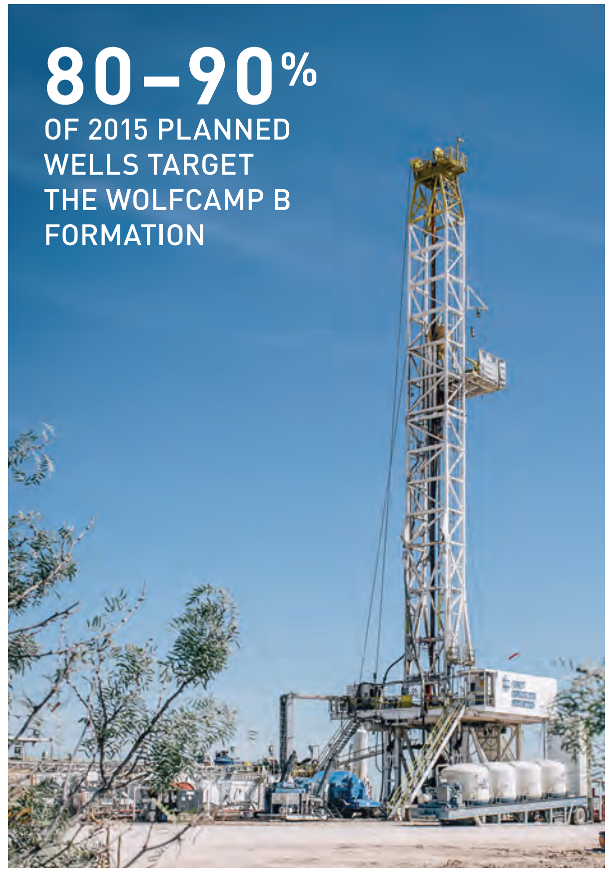
Over the course of 2014, we successfully transitioned from a vertical drilling company to one focused on horizontal drilling. The resulting increase in productivity—a function of basin-leading initial production rates from our horizontal wells—enabled us to grow net production by 184% year-over-year, averaging 14,200 barrels of oil equivalent per day (Boe/d) in 2014. More than 90% of that growth was achieved through the drill bit, and 77% of our 2014 production was oil and natural gas liquids.

Reserve growth was very strong in 2014, with proved reserves up 66% year-over-year to almost 91 million barrels of oil equivalent despite voluntarily writing off 14 MMBoe of vertical PUDs and associated recompletions. We replaced 694% of our 2014 oil and gas production volumes, and the PV-10 value of our proved reserves reached $1.3 billion at the end of the year, up 79% from the end of 2013. Organic growth accounted for the majority of our reserve additions. We also delivered solid financial results, increasing Adjusted EBITDA[1] by 168% from $77 million in 2013 to $206 million in 2014.

Taking into account political risk, repeatability, infrastructure, access to markets, and productivity, acreage in the Midland Basin constitutes one of the premier assets in the world, and we are fortunate to have accumulated a substantial acreage portfolio in the core of the play. Moreover, as a pure play E&P company, Parsley Energy offers greater dollar-for-dollar exposure to the core of the Midland Basin than essentially any other investment vehicle.

A series of bolt-on acquisitions executed throughout the year increased our Core and Tier 1 net acreage position by almost 60% during 2014, and we ended the year with more than 100,000 net acres in the Midland Basin. The majority of our acreage offers "stacked pay" potential to develop oil and gas from several prospective zones. We believe our acreage is in the deepest and thickest portion of the Midland Basin and that these characteristics, along with favorable thermal maturity, contribute to higher productivity, number of discrete target horizons, and resource potential.





Parsley Energy's exceptional horizontal well results are consistent with our superior asset quality. Each of the more than 20 horizontal wells we completed by the end of the year in the Wolfcamp A and B formations exceeded the 690 MBoe type curve we constructed from publicly available well data. In fact, after six months of production, cumulative production from our Wolfcamp wells has exceeded that associated with the type curve by 65%. The initial production rates associated with the Wolfcamp wells we have drilled and completed in our Core acreage are among the very best in the basin, averaging more than 200 Boe/d per 1,000 feet of stimulated lateral. Such prolific initial production rates translate into robust returns even in a depressed commodity price environment, with our Wolfcamp wells on track to pay out in less than two years on average. Our returns were also enhanced during 2014 by significant progress on the cost front, with both lease operating expense per BOE and general and administrative expense per BOE down almost 20%.

While 2014 was a year of accelerated growth, significant changes in the macroeconomic environment, including substantially lower commodity prices, have prompted a conservative capital program in 2015. We are pleased to be among the more nimble E&P companies, able to adapt quickly to changing conditions. As such, we intend to reduce our capital spending by half compared with

(1) EBITDA—earnings before interest, taxes, depreciation and amortization—is a non-GAAP measure. Please see a reconciliation to GAAP results in the accompanying 10-K.

2014 to a range of $225 million to $250 million. Despite the reduced capital program, we still expect to deliver annual production growth of approximately 30%—averaging 18,000-19,000 Boe/d—and to achieve attractive economics from each well we drill.

The shape of drilling activity in 2015 is intended to reflect an anticipated uplift in returns associated with declining costs for services and equipment, with two horizontal rigs running on average during the first half of the year and four horizontal rigs running on average during the second half of the year. Substantially all of Parsley's horizontal drilling activity will target zones from which the company has already generated strong well productivity, with 80-90% of horizontal wells targeting the Wolfcamp B zone. In order to hold acreage, the company intends to operate one vertical rig on an as-needed basis, representing approximately 10% of drilling and completion spending in 2015.

Looking ahead, we are confident that Parsley's asset base includes abundant value yet to be unlocked. We see substantial opportunity to de-risk additional formations, to reduce between-well spacing, and to develop our Southern Delaware acreage. Based on a six-rig run rate and using conservative 870-foot between-well spacing—or six wells per zone per section—we now have approximately 25 years of horizontal drilling inventory. Approximately one-third of this inventory consists of Wolfcamp A and B drilling locations, and having drilled highly productive Wolfcamp wells across the portion of our acreage in which our drilling locations are concentrated, we are confident in the repeatability of strong results across the entire location count.

WOLFCAMP WELLS OUTPERFORMING TYPE CURVE

At strip pricing[3], currently producing Wolfcamp wells on track to pay out in 2 years on average.

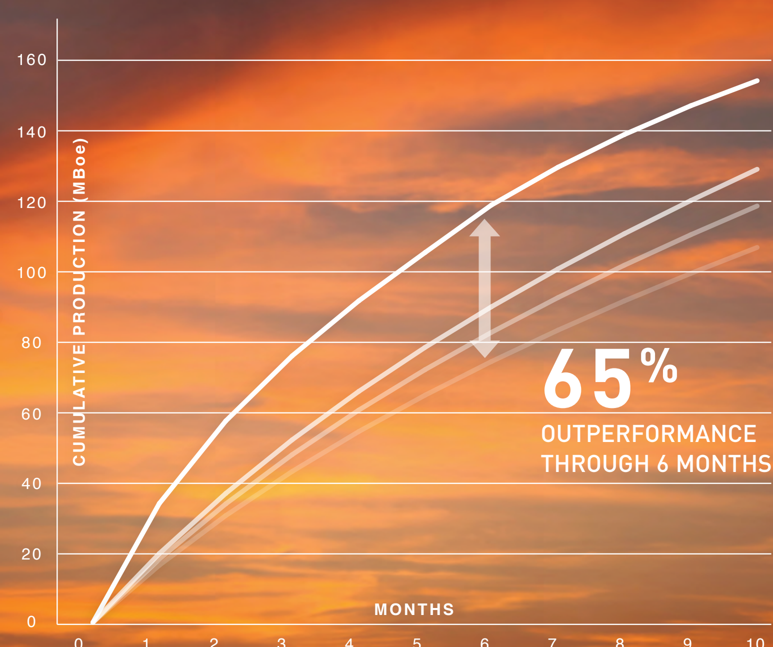
PE Average Horizontal Well Production[1]

20% EUR Increase: 830 MBoe

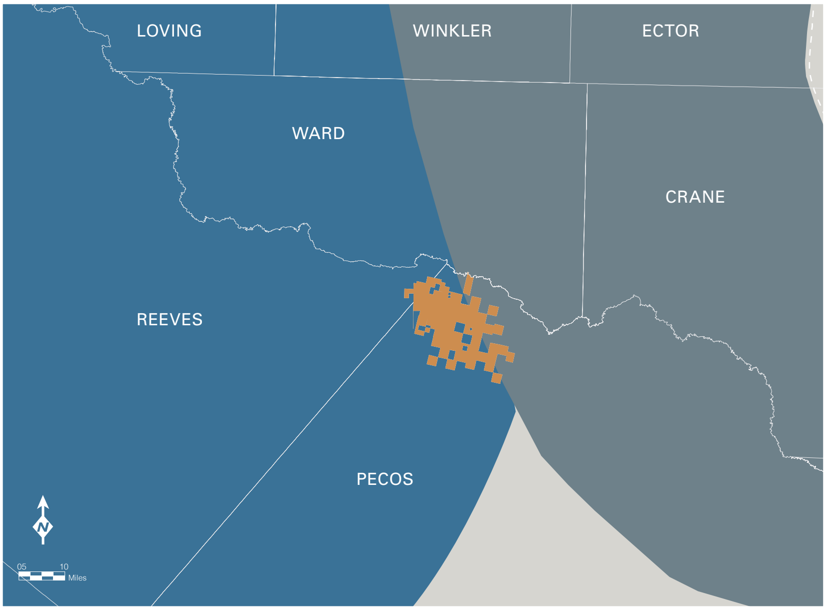
10% EUR Increase: 760 MBoe

690 MBoe EUR Type Curve[2]

(1) Normalized to 7,000 stimulated lateral and for downtime of 24 hours or more; includes all producing Wolfcamp A and B wells.
(2) Derived from public well data as of 10/14.
(3) Based on NYMEX strip pricing as of 3/18/2015.



SOUTHERN DELAWARE BASIN ACREAGE



Parsley's Southern Delaware acreage shows stacked pay potential, with particular promise in the Wolfcamp formation.

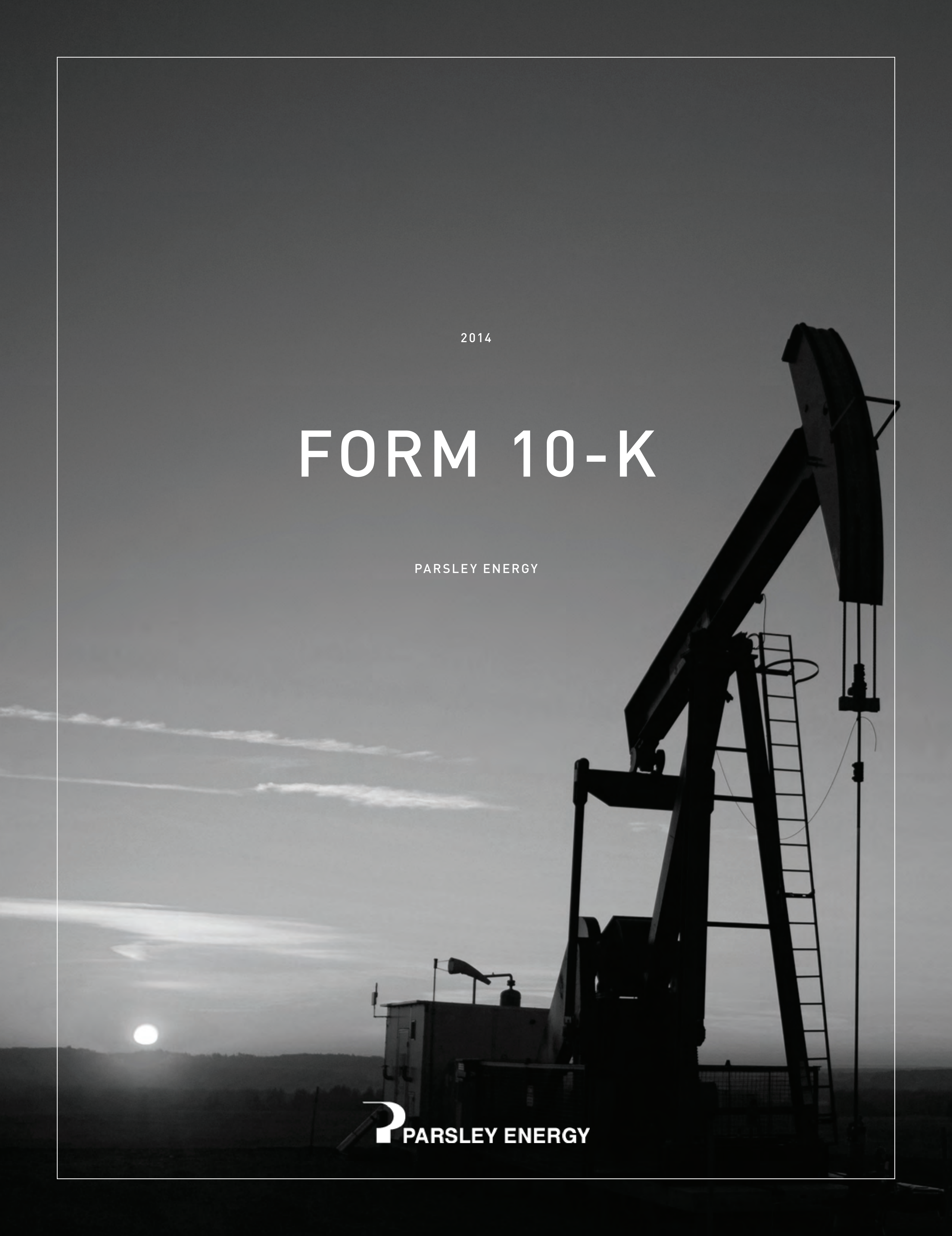
PARSLEY ACREAGE
CENTRAL BASIN PLATFORM
DELAWARE BASIN

We are very encouraged by the data we've gathered to date in the Southern Delaware Basin, where we hold approximately 30,000 net acres. Based on results from our vertical exploratory wells and offsetting well data from other producers in the area, we are excited about the potential for the horizontal development of the Wolfcamp formation on our Southern Delaware acreage.

Following a well-received private placement of common equity in February 2015 that raised $231 million of gross proceeds, we have a strong balance sheet and liquidity profile. With more than $500 million of liquidity, including a fully undrawn revolver, we are well-positioned to fund our growth plans. Our net debt to total capitalization at year end was less than 2.0, and we have no near-term maturities. In addition, almost all of our anticipated 2015 oil production is hedged, and we have more oil volumes hedged in 2016 than in 2015.

We are grateful for the confidence our investors have shown in our company as we've delivered on our promise to build a first-class asset base from which we're driving value in an efficient, disciplined manner. With our substantial drilling inventory in the "core of the core" of the Midland Basin and an enviable track record of highly productive horizontal wells, Parsley Energy is poised to deliver high-return growth across market cycles.

Bryan Sheffield
Chairman, President, and CEO
April 28, 2015



2014

FORM 10-K

PARSLEY ENERGY

PARSLEY ENERGY

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

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: 001-36463

PARSLEY ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**46-4314192**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
303 Colorado Street, Suite 3000 Austin, Texas	**78701**
(Address of principal executive offices)	(Zip Code)

(737) 704-2300
(Registrant's telephone number, including area code)

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

221 West 6th Street, Suite 750
Austin, Texas 78701
(Former address of principal executive offices)

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value	**New York Stock Exchange**

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

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

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

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

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

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2014 was approximately $1,795,805,293.

As of March 11, 2015, the registrant had 108,780,734 shares of Class A common stock and 32,145,296 shares of Class B common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2015 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of this fiscal year, are incorporated by reference into Part III of this Annual Report on Form 10-K.

PARSLEY ENERGY, INC.
FORM 10-K
ANNUAL PERIOD ENDED DECEMBER 31, 2014

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- ability to replace the reserves we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program;
- realized oil, natural gas and natural gas liquids ("NGLs") prices;
- timing and amount of future production of oil, natural gas and NGLs;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- ability to obtain permits and governmental approvals;
- pending legal or environmental matters;
- marketing of oil, natural gas and NGLs;
- leasehold or business acquisitions;
- costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this annual report that are not historical.

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

Should one or more of the risks or uncertainties described in this annual report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this annual report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10-K.

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The terms defined in this section are used throughout this Annual Report on Form 10-K:

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used in reference to crude oil, condensate or natural gas liquids.

"*Boe*." One barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"*Boe/d*." One barrel of oil equivalent per day.

"*British thermal unit*" or "*Btu*." The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"*completion*." The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*condensate*." A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"*development well*." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*dry hole*." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*economically producible*." A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC's Regulation S-X, Rule 4-10(a)(10).

"*exploitation*." A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

"*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 natural gas in another reservoir.

"*field*." An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

"*formation*." A layer of rock which has distinct characteristics that differ from nearby rock.

"*GAAP*." Accounting principles generally accepted in the United States.

"*gross acres*" or "*gross wells*." The total acres or wells, as the case may be, in which an entity owns a working interest.

"*horizontal drilling*." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*identified drilling locations*." Potential drilling locations specifically identified by our management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities.

"*lease operating expense*." All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

"*LIBOR*." London Interbank Offered Rate.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand barrels of oil equivalent.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBtu*." One million British thermal units.

"*MMcf*." One million cubic feet of natural gas.

"*natural gas liquids*" or " *NGLs*." The combination of ethane, propane, butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

"*net acres*" or "*net wells*." The percentage of total acres or wells, as the case may be, an owner has out of a particular number of gross acres or wells. For example, an owner who has 50% interest in 100 gross acres owns 50 net acres.

"*NYMEX*." The New York Mercantile Exchange.

"*operator*." The entity responsible for the exploration, development and production of a well or lease.

"*PE Units.*" The single class of units, in which all of the membership interests (including outstanding incentive units) in Parsley LLC were converted to in connection with the initial public offering.

"*proved developed reserves*." Proved reserves that can be expected to be recovered:

i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; or

ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"*proved reserves*." Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence, the project within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"*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.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"*reasonable certainty*." A high degree of confidence. For a complete definition, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

"*recompletion*." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"*reliable technology.*" A grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

"*reserves.*" Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development prospects 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 oil and natural gas or related substances to market and all permits and financing required to implement the project.

"*reservoir.*" A porous and permeable underground formation containing a natural accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"*SEC.*" The United States Securities and Exchange Commission.

"*spacing.*" The distance between wells producing from the same reservoir. Spacing is often established by regulatory agencies.

"*undeveloped acreage.*" Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

"*wellbore.*" The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

"*working interest.*" The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

"*workover*" Operations on a producing well to restore or increase production.

"*WTI.*" West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for other crude oils.

PART I

ITEM 1: BUSINESS

Overview

We are an independent oil and natural gas company focused on the acquisition, development and exploitation of unconventional oil and natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-areas: the Midland Basin, the Central Basin Platform and the Delaware Basin. These areas are characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. Our properties are primarily located in the Midland and Delaware Basins and our activities have historically been focused on the vertical development of the Spraberry, Wolfberry and Wolftoka Trends of the Midland Basin. Our vertical wells in the Permian Basin are drilled into stacked pay zones that include the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline), Strawn, Atoka and Mississippian formations. During the course of 2014 we transitioned from primarily vertical development drilling to predominantly horizontal development drilling activity.

On May 29, 2014, we completed our initial public offering (the "Offering") of 57.5 million shares of Parsley Energy, Inc.'s Class A Common Stock, par value $0.01 per share ("Class A Common Stock") at a price of $18.50 per share. Approximately 7.5 million of the shares were sold by selling stockholders and we did not receive any proceeds from the sale of those shares. The remaining approximately 50 million shares of Class A Common Stock that were sold resulted in gross proceeds of approximately $924.3 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $867.8 million. A portion of the proceeds from the Offering was used to repay all outstanding borrowings under the revolving credit agreement entered into on September 10, 2014 (the "Revolving Credit Agreement"), to make a cash payment in settlement of the Preferred Return (as defined herein), to fund the acquisition of certain oil and gas properties and to pay fees and expenses related to the Offering. The remaining proceeds were used to fund a portion of our exploration and development program and for general corporate purposes.

We began operations in August 2008 when we acquired operator rights to wells producing from the Spraberry Trend in the Midland Basin from Joe Parsley, a co-founder of Parker and Parsley Petroleum Company ("Parker and Parsley"). As of December 31, 2014, we continue to operate 87 gross (1.5 net) of these wells. Excluding those legacy 87 gross wells, as of December 31, 2014, we had an average working interest of 65% in 637 gross (414.9 net) producing wells. As of December 31, 2014, we have interests in 724 gross (416.4 net) producing wells, of which 722 gross (414.4 net) are in the Midland Basin and two gross (two net) are in the Delaware Basin. We operate 99% of the wells in which we have an interest. Since our inception, we have leased or acquired 133,274 net acres in the Permian Basin, approximately 103,036 of which is in the Midland Basin. Since we commenced our drilling program in November 2009, we have operated up to 12 rigs simultaneously and averaged 10 operated rigs for the year ended December 31, 2014. We are currently operating four horizontal rigs and one vertical drilling rig. We expect to average operating three horizontal rigs and one vertical rig for 2015.

We intend to grow our reserves and production through the development, exploitation and drilling of our multi-year inventory of identified drilling locations. As of December 31, 2014, we have identified 1,893 80- and 40-acre potential vertical drilling locations, 2,403 20-acre potential vertical drilling locations and 2,125 potential horizontal drilling locations on our existing acreage, which does not include any locations in Gaines County (Midland Basin) or in our Southern Delaware Basin acreage. We commenced our vertical appraisal drilling program in the Delaware Basin during the first quarter of 2014 and as of the date of this annual report, we have drilled and completed two vertical appraisal wells in that area. We believe our acreage in the Delaware Basin may also benefit from the application of horizontal drilling and completion techniques. We expect to supplement organic growth from our drilling program by proactively leasing additional acreage and selectively pursuing acquisitions that meet our strategic and financial objectives, with an emphasis on oil-weighted reserves in the Midland Basin.

Our 2015 capital budget for drilling and completion is approximately $225 million to $250 million. Our capital budget excludes any amounts that may be paid for acquisitions. For the year ended December 31, 2014, our capital expenditures for drilling and completions were $491.3 million, as compared to $268.4 million for all of fiscal year 2013, excluding in each period amounts paid for acquisitions. We expect the average working interest in wells we drill during 2015 will be approximately 90%.

The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

The following table summarizes our acreage and technically identified drilling locations in the Permian Basin as of December 31, 2014:

Area (2)	Net Acreage	Identified Drilling Locations(1) Horizontal (3)	Vertical(4) 80-and 40-acre	Vertical(4) 20-acre	Horizontal Drilling Inventory (Years (5))	Vertical Drilling Inventory (Years (6))
Midland Basin-Core..........	42,564	1,301	1,201	1,676	22	118
Midland Basin-Tier I..........	36,289	824	583	636	14	50
Midland Basin-Other..........	24,183	—	109	91	—	8
Southern Delaware Basin...	30,238	—	—	—	—	—
Total Permian Basin..........	133,274	2,125	1,893	2,403	36	176

(1) We have estimated our drilling locations based on well spacing assumptions for the areas in which we operate and other criteria. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in our adding additional proved reserves to our existing proved reserves. Also see ''Item 1A. Risk Factors."
(2) Please see "Item 2. Properties."
(3) Our target horizontal location count implies 660' to 870' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.
(4) Our total identified vertical drilling locations include 196 vertical locations on 80- and 40- acre spacing and no vertical locations on 20-acre spacing associated with proved undeveloped reserves as of December 31, 2014. Of these 196 vertical locations, 177 are in our Midland Basin-Core area, and 19 are in our Midland Basin-Tier I area.
(5) Based on a continuous five-rig program and an estimated spud to release time of 31.2 days.
(6) Based on a continuous one-rig vertical drilling program and spud to release time of 15 days.

As of December 31, 2014, our estimated proved oil and natural gas reserves at December 31, 2014, were 90.9 MMBoe based on a reserve report prepared by NSAI, our independent reserve engineers. Our proved reserves are approximately 52% oil, 25% NGLs, 23% natural gas and 51% proved developed.

Our Business Strategy

Our business strategy is to increase stockholder value through the following:

- ***Grow reserves, production and cash flow by exploiting our liquids rich resource base***. We intend to selectively develop our acreage base in an effort to maximize its value and resource potential. We intend to pursue drilling opportunities that offer competitive returns that we consider to be low risk based on production history and industry activity in the area, and repeatable as a result of well-defined geological properties over a large area. Through the conversion of our resource base to developed reserves, we will seek to increase our reserves, production and cash flow while generating favorable returns on invested capital.
- ***Improve operational and cost efficiency by maintaining control of our production***. We currently operate approximately 99% of the wells in which we have an interest and intend to maintain operational control of substantially all of our producing properties. We believe that retaining control of our production will enable us to increase recovery rates, lower well costs, improve drilling performance and increase ultimate hydrocarbon recovery through optimization of our drilling and completion techniques. Our management team regularly evaluates our operating results against those of other operators in the area in an effort to improve our performance and implement best practices. We have reduced the average time from spud to rig release for our vertical Spraberry and Wolfberry wells from approximately 18 days during 2011 to approximately 13 days in the fourth quarter of 2014. Our average total depth of wells drilled in 2014 was 11,411 feet. We have also reduced our total drilling, completion and facilities costs from a peak average of $2.4 million per well in the first quarter of 2012 to an average of $2.1 million per well in the fourth quarter of 2014. This decrease was driven primarily by a reduction in hydraulic fracturing costs and efficiencies gained through economies of scale over this time period. Additionally, we initiated cost reduction discussions with our suppliers beginning in November 2014. During the quarter ended December 31, 2014, we realized approximately 5-10% cost reductions on drilling and completion expenditures and further negotiations are ongoing.

- ***Pursue additional leasing and strategic acquisitions***. We regularly evaluate and complete acquisitions of undeveloped leasehold and producing properties that meet our strategic and financial objectives in the ordinary course of our business, with a focus primarily on our Midland Basin-Core area, while selectively pursuing other acquisition opportunities that meet our strategic and financial objectives. Our acreage position extends through what we believe are multiple oil and natural gas producing stratigraphic horizons in the Midland Basin, and we believe we can economically and efficiently add and integrate additional acreage into our current operations. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential and believe our management team's extensive experience operating in the Midland Basin provides us with a competitive advantage in identifying leasing opportunities and acquisition targets and evaluating resource potential.
- ***Maintain financial flexibility***. We intend to maintain a conservative financial position to allow us to develop our drilling, exploitation and exploration activities and maximize the present value of our oil-weighted resource potential. We intend to fund our growth with cash flow from operations, liquidity under our Revolving Credit Agreement and access to capital markets over time. As of December 31, 2014 pro forma for the Private Placement (as defined herein), we had approximately $519.2 million of liquidity, with $154.5 million of cash and cash equivalents and $364.7 million of available borrowing capacity under our Revolving Credit Agreement. Our borrowing base under the Revolving Credit Agreement currently stands at $560.8 million, although we have chosen to limit the aggregate commitment to $365.0 million. Consistent with our disciplined approach to financial management, we have an active commodity hedging program that seeks to hedge approximately 40% to 60% of our expected oil production on a rolling 24 to 36 month basis, reducing our exposure to downside commodity price fluctuations and enabling us to protect cash flows and maintain liquidity to fund our capital program and investment opportunities. In addition, we have hedged 3,300 MMBtu of our expected 2015 natural gas production. In periods of decreased drilling activity, our percentage of production hedged may increase above our stated goal. As a result of a reduction in our planned drilling activity, we have greater than 90% of expected oil production hedged in 2015, with more barrels hedged in 2016 than 2015.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- ***Extensive horizontal development potential***. We believe there are a significant number of horizontal locations on our acreage that will allow us to target the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline) and Atoka shales. In addition, based on our analysis of data acquired through our drilling program and the activities of offset operators, we believe that multiple benches contained within our acreage may have significant resource potential, which could substantially increase the ultimate hydrocarbon recovery of each surface acre we have under leasehold. Excluding our Gaines County (Midland Basin) and Southern Delaware Basin acreage, we had 2,125 identified horizontal drilling locations as of December 31, 2014. We initiated our horizontal development program with one rig during the fourth quarter of 2013 and have increased to five operated horizontal rigs as of December 31, 2014. Through December 31, 2014, we have drilled and placed on production 18 horizontal wells in the Midland Basin. As we continue to expand our vertical drilling program to our undeveloped acreage in Gaines County (Midland Basin) and the Southern Delaware Basin, we expect to identify additional horizontal drilling locations. The relatively low decline rate of our current production – a function of 694 vertical wells – enables us to grow production with lower capital investment.
- ***Incentivized management team with substantial technical and operational expertise***. Our management team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Spraberry, Wolfberry and Wolftoka Trends of the Permian Basin. Our chief executive officer, Bryan Sheffield, is a third generation oil and gas executive, and our management team has previous experience at Parker and Parsley, Concho Resources, Chesapeake Energy Corporation, Pioneer Natural Resources, and Whiting Petroleum Corporation. We have also assembled a technical team that includes twelve petroleum engineers and six geologists with an average of eleven years of experience, which we believe will be of strategic importance as we continue to expand our future exploration and development plans. Our management team holds approximately 34.0% of our ownership interest and is our largest stockholder group. We believe our management team's significant ownership interest provides meaningful incentive to increase the value of our business for the benefit of all stockholders.
- ***Operating control over approximately 99% of our production***. As of December 31, 2014, we operated approximately 99% of the wells in which we have an interest. We believe that maintaining control of our production enables us to dictate the pace of development and better manage the cost, type and timing of exploration, exploitation and development activities. Our leasehold position is comprised primarily of properties that we operate and, excluding our Gaines County (Midland Basin) and Southern Delaware Basin acreage, includes an estimated 1,893 80- and 40-acre potential vertical drilling locations, 2,403 20-acre potential vertical drilling locations and 2,125 potential horizontal drilling locations.

- ***Conservative balance sheet***. We expect to maintain financial flexibility that will allow us to develop our drilling activities and selectively pursue acquisitions. As of December 31, 2014 pro forma for the Private Placement (as defined herein), we do not have any debt outstanding under our Revolving Credit Agreement and $364.7 million of available borrowing capacity. We believe this borrowing capacity, along with our cash flow from operations, will provide us with sufficient liquidity to execute on our current capital program.

Recent Events

Recent Horizontal Well Results

The following table provides a summary of all wells completed during the fourth quarter of 2014 that have sufficient production data:

Area	Well Count	30-Day Average IP Rate (Boe/d)		90-Day Average Cumulative Production (Boe)	Average Total Depth (feet)
Midland Basin – Core	13	396	(1)	26,212	15,431
Midland Basin – Tier I	5	544	(2)	33,743	13,281

(1) Consisting of 333 Bbls/d of oil and 380 Mcf/d of natural gas. NGLs production and sales are included in our natural gas production and sales.

(2) Consisting of 443 Bbls/d of oil and 604 Mcf/d of natural gas. NGLs production and sales are included in our natural gas production and sales.

Recent Acquisition Activity

During the fourth quarter of 2014, we acquired a total of 8,450 net acres in the Permian Basin for approximately $139 million. The acreage, primarily in northwest Reagan County, Texas, is undeveloped, 100% operated, and adjacent to our horizontal development operations. The acquisitions add 199 net horizontal drilling locations and 410 net vertical drilling locations.

Private Placement of Common Stock

On February 5, 2014, we entered into an agreement to sell 14,885,797 shares of our Class A Common Stock in a private placement at a price of $15.50 per share (the "Private Placement") to selected institutional investors. The Private Placement closed on February 11, 2015 and resulted in approximately $231 million of gross proceeds and approximately $224 million of net proceeds (after deducting placement agent commissions and our expenses). We used the net proceeds of the Private Placement to repay a portion of outstanding borrowings under our Revolving Credit Agreement and for general corporate purposes.

Organizational Structure

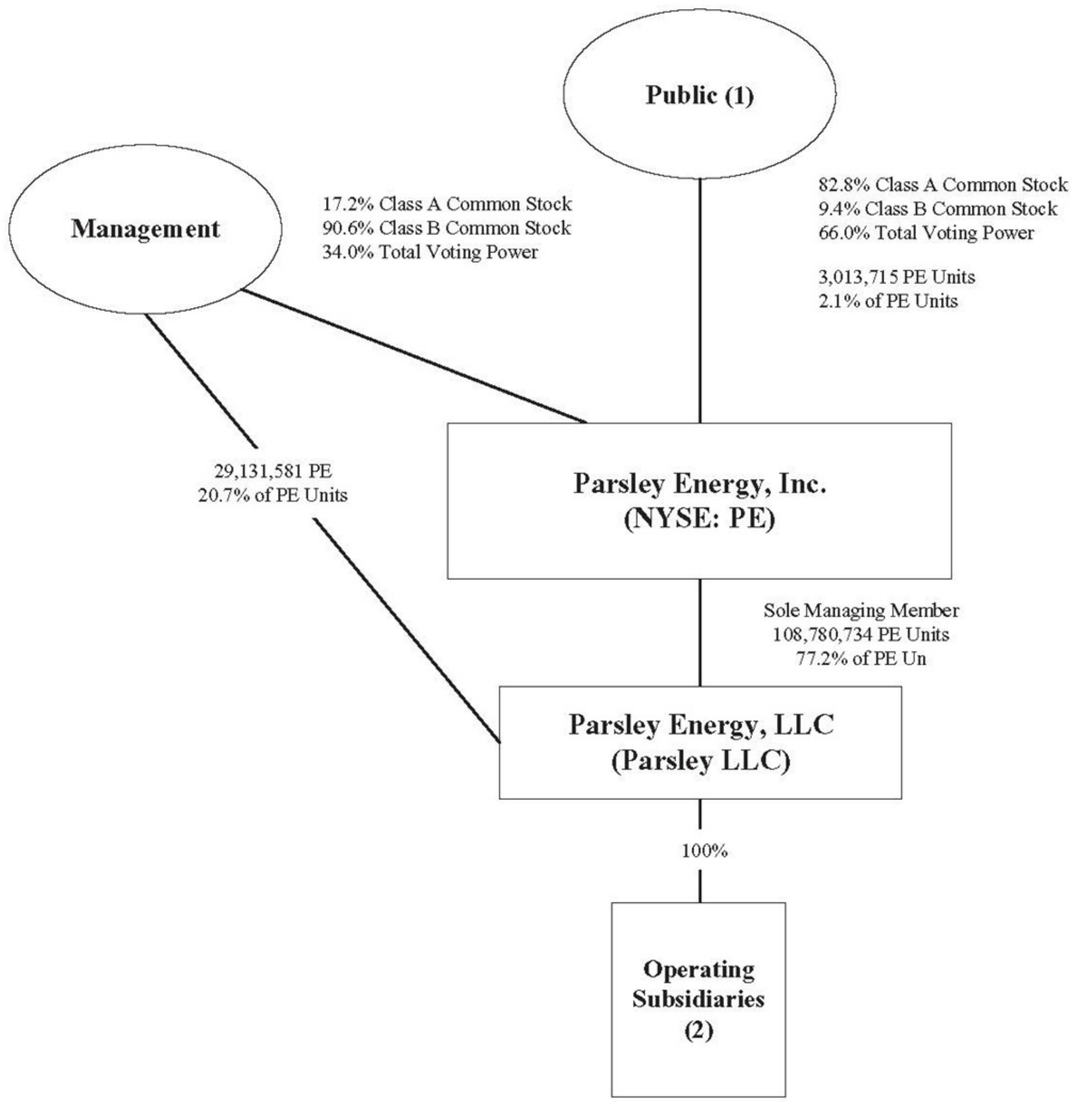
We are a holding company that was incorporated as a Delaware corporation on December 11, 2013 for the purpose of facilitating an initial public offering ("IPO") of common equity and to become the sole managing member of Parsley Energy, LLC, which we refer to as "Parsley LLC". Our principal asset is a controlling equity interest in Parsley LLC. On May 22, 2014, a registration statement filed on Form S-1 with the SEC related to shares of Class A Common Stock was declared effective. The IPO closed on May 29, 2014. Prior to the IPO, we had not engaged in any business or other activities except in connection with its formation and the IPO.

After the effective date of the registration statement but prior to the completion of the IPO, the limited liability company agreement of Parsley LLC was amended and restated to modify its capital structure by replacing the different classes of interests previously held by Parsley LLC owners with a single new class of units called "PE Units." In addition, each PE Unit holder received one share of our Class B Common Stock ("Class B Common Stock"). Pursuant to such amended and restated limited liability company agreement (the "Parsley Energy LLC Agreement"), each PE Unit holder has the right to exchange their PE Units together with an equal number of shares of our Class B Common Stock, for shares of our Class A Common Stock (or cash at our or Parsley LLC's election (the "Cash Option")) on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications (the "Exchange Right"). In addition, in connection with the IPO, we entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC, the PE Unit holders and certain of our other equity owners (each such person, a "TRA Holder"). This agreement generally provides for the payment by Parsley Energy, Inc. to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state or local income tax that Parsley Energy, Inc. actually realizes (or is deemed to realize in certain circumstances) in periods after the IPO as a result of (i) any tax basis increases resulting from the contribution in connection with the IPO by such TRA Holder of all or a portion of its PE Units to Parsley Energy, Inc. in exchange for shares of Class A Common Stock,

(ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A Common Stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. We will retain the benefit of the remaining 15% of these cash savings. See "Certain Relationships and Related Transactions, and Director Independence" and "Management's Discussion and Analysis of Financial Conditions and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Corporate Reorganization." These transactions are collectively referred to as the "Reorganization Transactions."

As a result of the IPO and the related Reorganization Transactions, we became the sole managing member of, and has a controlling equity interest in, Parsley LLC. As the sole managing member of Parsley LLC, we operate and control all of the business and affairs of Parsley LLC and, through Parsley LLC and its subsidiaries, conduct our business. We consolidate the financial results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interest in Parsley LLC held by the Parsley LLC Unit holders.

The following diagram indicates our organizational structure as of March 11, 2015. This chart is provided for illustrative purposes only and does not represent all legal entities affiliated with us.



(1) Includes shares of our Class A Common Stock held by Natural Gas Partners, through NGP X US Holdings, L.P. (collectively, "NGP") and shares of our Class A Common Stock held by legacy owners.

(2) Includes Parsley Finance Corp.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and NGLs, and certain price and cost information for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
Revenues (in thousands, except percentages):			
Oil sales	$ 232,554	$ 97,839	$ 30,443
Natural gas and natural gas liquid sales	69,203	23,179	7,236
Total revenues	$ 301,757	$ 121,018	$ 37,679
Average realized prices(1):			
Oil sales, without realized derivatives (per Bbls)	$ 81.91	$ 93.28	$ 85.60
Oil sales, with realized derivatives (per Bbls)	$ 81.33	$ 87.91	$ 83.08
Natural gas and NGLs, without realized derivatives (per Mcf)	$ 4.92	$ 4.95	$ 4.85
Natural gas and NGLs, with realized derivatives (per Mcf)	$ 4.96	$ 4.95	$ 4.85
Average price per BOE, without realized derivatives	$ 58.19	$ 66.17	$ 62.33
Average price per BOE, with realized derivatives	$ 58.00	$ 63.09	$ 60.85
Production:			
Oil (MBbls)	2,839	1,049	356
Natural gas and natural gas liquid (MMcf)	14,074	4,680	1,493
Total (MBoe)(2)	5,186	1,829	604
Average daily production volume:			
Oil (Bbls/d)	7,778	2,874	972
Natural gas and natural gas liquids (Mcf/d)	38,559	12,823	4,079
Total (Boe/d)	14,207	5,011	1,652

(1) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

Productive Wells

As of December 31, 2014 we owned an average 65% working interest in 724 gross (416.4 net) productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

General

As of December 31, 2014, we operated approximately 99% of the wells in which we have an interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2014, five purchasers each accounted for more than 10% of our revenue during the period: Atlas Pipeline Mid – Continent WestTex, LLC ("Atlas"), Plains Marketing, LP ("Plains"), BML, Inc., Permian Transport & Trading ("PTT") and Enterprise Crude Oil, LLC ("Enterprise"). For the year ended December 31, 2013, four purchasers, PTT, Plains, Enterprise and Atlas, each accounted for more than 10% of our revenue. For the year ended December 31, 2012, five purchasers each accounted for more than 10% of our revenues: Enterprise, Plains, Shell Trading (US) Company, Atlas and PTT. No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a materially adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The purchaser then transports the oil by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering system.

In addition, we move the majority of our produced water by pipeline connected to commercial salt water disposal wells rather than by truck. However, due to the inaccessibility of certain of our wells, some produced water will likely always be required to be taken away by truck. We believe that the completion of gathering systems, the connection to salt water disposal wells and other actions will help us to reduce our lease operating expense in future periods.

In the third quarter of 2014, we entered into an agreement with a private midstream services company for firm pipeline capacity from our North Upton County and South Midland County acreage to Colorado City, Texas, which will enable us to bypass the Midland pricing market for a substantial portion of our crude oil production when pipeline deliveries commence.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and 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 oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. 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, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Segment Information and Geographic Areas

We operate in one industry segment, which is the exploration, development and production of oil and natural gas, and all of our operations are conducted in one geographic area of the United States.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced, if any, will depend on numerous factors beyond our control, the effect of which factors cannot be accurately predicted or anticipated. Some of these factors include, without limitation, the availability of other domestic and foreign production, the marketing of competitive fuels, the proximity and capacity of pipelines, fluctuations in supply and demand, the availability of a ready market, the effect of United States federal and state regulation of production, refining, transportation and sales and general national and worldwide economic conditions. Additionally, we may experience delays in marketing natural gas production and fluctuations in natural gas prices, and our marketing professionals may experience short-term delays in marketing oil due to trucking and refining constraints. There is no assurance that we will be able to market any oil or natural gas produced, or, if such oil or natural gas is marketed, that favorable prices can be obtained.

The United States natural gas market has undergone several significant changes over the past few decades. The majority of federal price ceilings were removed in 1985 and the remainder were lifted by the Natural Gas Wellhead Decontrol Act of 1989. Thus, currently, the United States natural gas market is operating in a free market environment in which the price of gas is determined by market forces rather than by regulations. At the same time, the domestic natural gas industry has also seen a dramatic change in the manner in which gas is bought, sold and transported. In most cases, natural gas is no longer sold to a pipeline company. Instead, the pipeline company now serves the role of transporter primarily, and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

Recently, natural gas prices have been under considerable pressure due to supply excesses. Specifically, increased efficiencies in horizontal drilling combined with exploration of newly developed shale fields in North America have dramatically increased annual domestic natural gas production, which has led to significantly lower market prices for natural gas. However, some produced natural gas contains within its stream NGLs, which can be processed and stripped from the produced gas and marketed separately. These NGLs, such as propane, butane and ethane, generally bring a price premium over dry natural gas. As a result, the drilling program will be favorably affected if the production includes a significant amount of NGLs. There is no guarantee that we, through our drilling program, will be successful at drilling wells that produce NGLs. It is particularly difficult to estimate accurately future prices of gas, and any assumptions concerning future prices may prove incorrect.

The United States average daily production of crude oil declined from 9.6 million barrels in 1970 to approximately 4.95 million barrels in 2008 as a result of decreased drilling activity in the United States, the plugging and abandoning of wells and restrictions on access to potential drilling sites by governmental agencies. Over the last seven years, however, as a result of new technology, such as hydraulic fracturing, and rising oil prices, the United States average daily production of crude oil has risen, and the U.S. Energy Department projects that daily output will continue to increase.

The United States import levels for oil have decreased since reaching a peak, when imports averaged approximately 60% in 2005.

In view of the many uncertainties affecting the supply and demand for oil, gas and refined petroleum products, we are unable to predict future oil and natural gas prices or the overall effect, if any, that the decline in demand for and the oversupply of such products will have on the partnership

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (the "FERC") and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

Natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGLs and gas within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices of gas, oil, condensate and NGLs are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state, and potentially federal, reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced by the partnership, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the Energy Policy Act of 2005 ("EPAct 2005"). Under the EPAct 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the Natural Gas Act of 1938 ("NGA") to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to $1.0 million per day per violation. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, any market participant, including a producer such as us that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and service conditions for interstate transportation of oil, including NGLs, under the Interstate Commerce Act ("ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows for the partnership.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity or for new shippers. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly-situated competitors.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly-situated competitors.

In addition to FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this current level of regulation will continue in the future.

The following is a summary of the more significant existing and proposed environmental, health and safety laws and regulations to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

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

We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses natural gas, we may nonetheless 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 released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

The Oil Pollution Act of 1990 ("OPA"), amends the Clean Water Act and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, OPA requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures ("SPCC") plans. We continue to review our properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

Safe Drinking Water Act

In the course of our operations, we produce water in addition to oil and gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act ("SDWA") and permitting and enforcement authority may be delegated to the states. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. In response to these concerns, regulators in some states are considering additional requirements related to seismic safety. For example, the RRC recently adopted new permit rules for injection wells to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. These new rules could impact the availability of injections wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may our reduce profitability; however, these costs are commonly incurred by all oil and gas producers and we do not believe that the costs associated with the disposal of produced water will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, the EPA has promulgated rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Standards for Emission of Hazardous Air Pollutants ("NESHAPS") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound ("VOC") emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells must use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. The rule is designed to limit emissions of VOC, sulfur dioxide, and hazardous air pollutants from a variety of sources within natural gas processing plants, oil and natural gas production facilities, and natural gas transmission compressor stations. This rule could require a number of modifications to our operations including the installation of new equipment. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain Prevention of Significant Deterioration ("PSD") permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. More recently, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Also, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Further, the EPA has announced its intention to propose regulations under the CWA by sometime in 2015 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the EPA is conducting a study of the potential impacts of hydraulic fracturing activities on water resources and a draft final report is anticipated sometime in 2015 for peer review and public comment. The results of this study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Also, the U.S. Department of the Interior issued proposed rules in May 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. A final version of these rules may be adopted in 2015.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal Endangered Species Act ("ESA"), and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. For example, in March 2013, the U.S Fish and Wildlife Service ("FWS") listed the lesser prairie chicken as a threatened species under the ESA. Although the lesser prairie chicken's habitat includes areas of the Permian Basin, where we operate, we do not believe that this listing will have a significant impact on our operations. Moreover, as a result of a 2011 settlement agreement, the FWS is required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency's 2017 fiscal year. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the OSHA and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations. Further, we have no coverage for gradual, long-term pollution events.

In summary, we believe we are in substantial compliance with currently applicable environmental, occupational health and safety laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, nor do we anticipate that such expenditures will be material in 2015.

Employees

As of December 31, 2014, we employed 174 people. Our future success will depend in part on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly, and current reports, proxy statements, and other documents with the SEC under the Exchange Act. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549, on official business days during the hours of 10 a.m. to 3 p.m. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet website at *ww.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC.

Our Class A Common Stock is listed and traded on the New York Stock Exchange under the symbol "PE." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available free of charge through our website, *www.parsleyenergy.com*, electronic copies of certain documents that we file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

You should carefully consider the following risks and all of the information contained in this Annual Report on Form 10-K. Our business, financial condition, and results of operations could be materially and adversely affected by any of these risks. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we consider immaterial also may adversely affect us.

Risks Related to the Oil and Natural Gas Industry and Our Business

Oil and natural gas prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Prices for oil and natural gas can fluctuate widely. For example, during 2014, NYMEX West Texas Intermediate crude oil prices ranged from a high of $107.26 per barrel to a low of $53.61 per barrel at the end of 2014. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 MMBtu to a low of $3.01 per MMBtu during 2014. The duration and magnitude of the recent decline in crude oil prices cannot be predicted. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;
- the price and quantity of foreign imports;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

In recent months, prices for U.S. crude oil have weakened in response to a buildup in inventories and lower global demand. An announcement by the Organization of the Petroleum Exporting Countries in November 2014, in which the organization indicated it would not cut its oil production, further depressed crude prices.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease, a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our exploitation, development and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of oil and natural gas reserves. We expect to fund 2015 capital expenditures with cash generated by operations, borrowings under our Revolving Credit Agreement and possibly through additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our Revolving Credit Agreement. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity.”

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

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Revolving Credit Agreement.

If our revenues or the borrowing base under our Revolving Credit Agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our Revolving Credit Agreement are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations.

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

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards, tornados and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems or legal disputes regarding leasehold rights; and
- limitations in the market for oil and natural gas.

Our identified drilling locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain 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 natural gas or oil from these or any other potential locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our $750 million Revolving Credit Agreement and our senior unsecured notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Revolving Credit Agreement and the indenture governing our senior unsecured notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Revolving Credit Agreement and the indenture governing our senior unsecured notes contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production or interest rates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our Revolving Credit Agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our Revolving Credit Agreement impose on us.

Our Revolving Credit Agreement limits the amount we can borrow up to the lower of our aggregate lender commitments and a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Agreement. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid.

A breach of any covenant in our Revolving Credit Agreement would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the relevant facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

If we are unable to comply with the restrictions and covenants in our Revolving Credit Agreement, there could be an event of default under the terms of our Revolving Credit Agreement, which could results in an acceleration of repayment.

If we are unable to comply with the restrictions and covenants in our Revolving Credit Agreement, there could be an event of default under the terms of this facility. Our ability to comply with these restrictions and covenants, including meeting the financial ratios and tests under our Revolving Credit Agreement, may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or continue to decline, our ability to comply with these covenants may be impaired. We cannot assure that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. In the event of a default under our Revolving Credit Agreement, the lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend our Revolving Credit Agreement or obtain needed waivers on satisfactory terms.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts for a significant portion of our production, primarily consisting of put spreads and three way collars. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Our Properties—Sources of Our Revenues" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Our Properties—Realized Prices on the Sale of Oil, Natural Gas and NGLs." Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have an adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Approximately 78% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2014, approximately 78% of our net leasehold acreage was undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. At December 31, 2014, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. As an example, since all of our production originates in Midland, Texas, our realizations on sales of our oil production may be affected by the Midland-Cushing price differential, which reflects the difference between the price of crude at Midland, Texas, versus the price of crude at Cushing, Oklahoma, a major hub where production from Midland is often transported via pipeline. The price we currently realize on barrels of oil we sell is reduced by the value of the Midland-Cushing differential, which reached as high as $21 per barrel in August 2014. If the Midland-Cushing differential, or other price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

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

The marketing of oil, NGLs and natural gas production depends in large part on the availability, proximity and capacity of pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. If there is insufficient capacity available on these systems, or if these systems are unavailable to us, the price offered for our production could be significantly depressed, or we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while we construct our own facility. We also rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transport and sell our oil, NGLs and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing facilities to us, especially in areas of planned expansion where such facilities do not currently exist.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production.

The marketing of oil and gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities were unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as winter storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. For example, severe winter weather and the resulting extensive power outages caused our production in the fourth quarter of 2014 to decline significantly. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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 natural 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 lease brokers or land men who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. 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 do 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.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2014, 49% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 44.9 MMBoe of estimated proved undeveloped reserves will require an estimated $627 million of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources, such as capital markets, our Revolving Credit Agreement and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

SEC rules and reserves auditing guidelines could limit our ability to book additional proved undeveloped reserves (PUDs) in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they related to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

In addition, the methodology used by our independent reserves engineers, NSAI, may limit our ability to book additional horizontal proved undeveloped reserves. NSAI currently permits operators to book proved undeveloped reserves only for the slots immediately adjacent to the East and West of producing horizontal wells, but not North and South of such producing wells. This methodology has limited and may continue to limit our ability to book additional proved undeveloped reserves relating to horizontal production as we pursue our drilling program.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may incur impairment charges in 2015, which may have a material adverse effect on our results of operations.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. Further, the horizontal decline curve we use to project our future production is subject to numerous limitations. The type curve was prepared by our internal reserve engineers and is based on publicly-available third party production data rather than our own production data, due to our limited horizontal production history. Such public data is not extensive and the production results from the wells comprising the data set may differ from our own wells due to geographic location, completion techniques, and a variety of other well characteristics. As a result, our projected production results and EURs may differ substantially from our actual production results and ultimate recoveries.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See “Business—Oil and Natural Gas Production Prices and Production Costs— Marketing and Customers.” We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas. Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;

- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

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

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our Revolving Credit Agreement and the indenture governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions. Our Revolving Credit Agreement and the indenture governing our senior unsecured notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We are subject to complex U.S. federal, state, local and other laws and regulations related to environmental, health, and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, the occupational health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, and results of operations.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. See "Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the Federal Trade Commission has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1 million per day, and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to crude oil swaps and futures contracts as that granted to the CFTC with respect to crude oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Business—Regulation of the Oil and Natural Gas Industry."

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential 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 response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. More recently, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels, and published permitting guidance in February 2014 addressing the performance of such activities. Also, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Further, the EPA has announced its intention to propose regulations under the CWA by sometime in 2015 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the EPA is conducting a study of the potential impacts of hydraulic fracturing activities on water resources and a draft final report is anticipated sometime in 2015 for peer review and public comment. The results of this study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise Also, the U.S. Department of the Interior published a revised proposed rule on May 16, 2013, that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Further regulation of hydraulic fracturing at the federal, state, and local level could subject our operations to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. Please read "Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, and raising additional capital, which could have a material adverse effect on our business.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Our operations and drilling activity are concentrated in the Permian Basin of West Texas, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could result in oil and gas production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our results of operations, liquidity and financial condition.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile commodity prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. With the exception of Bryan Sheffield, our President and Chief Executive Officer, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations. For example, in the event that Mr. Sheffield no longer controls the entity that is the sub-operator of the 98 legacy wells we assumed from Parker and Parsley, the sub-operating agreement governing the terms of our arrangement could terminate and we would no longer be the operator of record on these wells. If the sub-operating agreement were to terminate, we would be unable to dictate the pace of development and manage the cost, type, and timing of the drilling program on these identified drilling locations, which could impact our ability to recognize the proved undeveloped reserves associated with these properties.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly over the last several years. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. As of December 31, 2014, we had spud 24 gross (19 net) horizontal wells and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Potential disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

The Fiscal Year 2016 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. However, Texas has endured severe drought conditions over the past several years. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations from local sources, we may be unable to produce oil and natural gas economically, which could have an adverse effect on our financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

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

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide derivative transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Columbia in September of 2012 although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap," "security-based swap," "swap dealer" and "major swap participant." The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

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

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or 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, our business, financial condition or results of operations could be materially and adversely affected.

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

As an oil and gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability.

Risks Related to our Class A Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we are required to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are required to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NYSE;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ended December 31, 2014, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an “emerging growth company” within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, while we anticipate that we will cease to be an “emerging growth company” at the end of 2015, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2019. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Compliance with these requirements may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

We are a holding company. Our sole material asset is our equity interest in Parsley LLC and we are accordingly dependent upon distributions from Parsley LLC to pay taxes, make payments under the TRA and cover our corporate and other overhead expenses.

We are a holding company and have no material assets other than our equity interest in Parsley LLC. We have no independent means of generating revenue. To the extent Parsley LLC has available cash, we intend to cause Parsley LLC to make distributions to its unitholders, including us, in an amount sufficient to cover all applicable taxes at assumed tax rates and payments under the TRA, and to reimburse us for our corporate and other overhead expenses. We are limited, however, in our ability to cause Parsley LLC and its subsidiaries to make these and other distributions to us due to the restrictions under our credit facilities. To the extent that we need funds and Parsley LLC or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Our principal stockholders will collectively hold a substantial majority of the voting power of our common stock.

Holders of Class A common stock and Class B common stock will vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our certificate of incorporation. Our management team holds approximately 34.0% of our ownership interest and is our largest stockholder group. The existence of significant stockholders may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as our management team continues to control a significant amount of our common stock, they will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of our management team may differ or conflict with the interests of our other stockholders. In addition, NGP and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. NGP and its affiliates may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Moreover, this concentration of stock ownership may also adversely affect the trading price of our Class A common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption "Certain Relationships and Related Transactions, and Director Independence."

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

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

- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

In addition, certain change of control events have the effect of accelerating the payment due under our TRA, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company. Please see "—In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA."

Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any director or officer or other employee of ours arising pursuant to any provision of the Delaware General Corporation Law (the "DGCL"), our amended and restated certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us or any director or officer or other employee of ours that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our amended and restated certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay dividends on our Class A common stock, and our credit facilities place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Class A common stock appreciates.

We do not plan to declare dividends on shares of our Class A common stock in the foreseeable future. Additionally, our credit facilities place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your Class A common stock at a price greater than you paid for it. There is no guarantee that the price of our Class A common stock that will prevail in the market will ever exceed the price at which you purchased your shares of Class A common stock.

We will be required to make payments under the TRA for certain tax benefits we may claim, and the amounts of such payments could be significant.

The TRA generally provides for the payment by us to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state or local income tax that we actually realize (or are deemed to realize in certain circumstances as a result of (i) any tax basis increases resulting from the contribution in connection with the IPO by such TRA Holder of all or a portion of its PE Units to Parsley Inc. in exchange for shares of Class A common stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A common stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. In addition, payments we make under the TRA will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The payment obligations under the TRA are our obligations and not obligations of Parsley LLC. For purposes of the TRA, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the TRA. The term of the TRA will continue until all such tax benefits have been utilized or expired, unless we exercise our right to terminate the TRA by making the termination payment specified in the agreement.

The actual increase in tax basis, as well as the amount and timing of any payments under the TRA, will vary depending upon a number of factors, including the timing of the exchanges of PE Units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the TRA constituting imputed interest or depletable, depreciable or amortizable basis. We expect that the payments that we will be required to make under the TRA could be substantial.

The payments under the TRA will not be conditioned upon a holder of rights under the TRA having a continued ownership interest in us. See “Certain Relationships and Related Transactions, and Director Independence.”

In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA.

If we elect to terminate the TRA early or it is terminated early due to certain mergers or other changes of control we would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the TRA, which calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the TRA, including the assumption that we have sufficient taxable income to fully utilize such benefits and that any PE Units that the PE Unit Holders or their permitted transferees own on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of such future benefits.

In these situations, our obligations under the TRA could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction cost a potential acquirer may attribute to satisfying such obligations.

Payments under the TRA will be based on the tax reporting positions that we will determine. The holders of rights under the TRA will not reimburse us for any payments previously made under the TRA if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any such holder will be netted against payments otherwise to be made, if any, to such holder after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity.

We may issue preferred stock whose terms could adversely affect the voting power or value of our Class A common stock.

Our amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our Class A common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our Class A common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the Class A common stock.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A common stock.

For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements that apply to other public companies.

In April 2012, President Obama signed into law the Jumpstart Our Business Startups Act (the "JOBS Act"). For as long as we remain an "emerging growth company" as defined in the JOBS Act, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act and reduced disclosure obligations regarding executive compensation in our periodic reports. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, the date on which we become a “large accelerated filer” (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter), or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies.

The corporate opportunity provisions in our amended and restated certificate of incorporation could enable NGP to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our amended and restated certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (1) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (2) acted in bad faith or in a manner inconsistent with our best interests.

As a result, NGP or their affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to NGP and their affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties are located in the West Texas portion of the Permian Basin. As of December 31, 2014, our acreage position consisted of 133,274 net acres, 103,036 of which are in the Midland Basin and 30,238 of which are in the Delaware Basin, approximately 34% of which is held by production. As of December 31, 2014, we have interests in 724 gross (416.4 net) producing wells, of which we operate 99%. Of these wells, 542 were drilled by us since initiating our drilling program in November 2009. The table below sets forth our identified drilling locations in the Midland Basin as of December 31, 2014.

	Target Horizontal Locations					
	Short Laterals(1)		Long Laterals(1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Horizontal Zone						
Spraberry	164	131	27	22	191	153
Wolfcamp A	258	219	88	77	346	296
Wolfcamp B	247	212	100	88	347	300
Wolfcamp C	265	224	110	97	375	321
Upper Pennsylvanian (Cline)	285	246	112	100	397	346
Atoka	356	308	113	101	469	409
Total Target Horizontal Location	1,575	1,340	550	485	2,125	1,825

	Target Vertical Locations(2)					
	80-and 40-Acre		20-Acre		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Vertical Locations	1,893	1,351	2,403	1,743	4,296	3,094
Total Target Horizontal and Vertical Locations					6,421	4,919

(1) Our target horizontal location count implies 660' to 870' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

(2) Ascribes no vertical locations to our Gaines County (Midland Basin) acreage.

The Permian Basin is an area that extends through multiple counties in Southeast New Mexico and West Texas and covers an area some 250 miles wide and 300 miles long. It is comprised of three main sub-areas, the Delaware Basin, the Central Basin Platform and the Midland Basin. The Permian Basin is characterized by oil and liquids rich gas production. According to the RRC, over 29 billion barrels of oil and 75 trillion cubic feet of gas have been produced in the Permian Basin since the first producing well was drilled in 1921 in Mitchell County. Historically, conventional reservoirs have been targeted and successfully produced in all three sub-areas. Over the past 30 years, there has been an increase in multi-stage fracturing treatments targeting and commingling production from multiple tight, stacked pay, unconventional formations. With the advent of horizontal drilling and the application of multi-stage fracture treatments within one horizontal well bore, activity has increased drastically targeting one unconventional formation at a time for production.

Midland Basin

Throughout the middle and late Pennsylvanian period, the Midland Basin was a very shallow and generally poorly defined area dominated by marine shale and limestone deposition. Organic content of the marine shale increased as the basin slowly subsided. Tectonic uplift of the Central Basin Platform and coincident emergence of the Eastern Shelf during the early Permian period brought greater definition to the Midland Basin as a distinct physiographic feature. Slow subsidence and basin filling with organic shale and limestone continued to dominate deposition. During middle Permian period more emergent surrounding shelf areas to the northwest and south-southwest contributed thick volumes of clastic sand that molded with the shale and limestone and formed the widespread Spraberry formation throughout the Permian Basin. In the later Permian time period, there was basin-wide infilling and subsequent burial with massive evaporate deposition.

The Midland Basin has historically been characterized by production from its most prolific field, the Spraberry Trend Area. The Spraberry Trend Area has been heavily drilled since the discovery of the Seaboard No. 2-D Lee well in Dawson County in 1949. The field stretches over 150 miles North to South and over 75 miles East to West. According to RRC, over 1.2 billion barrels of oil have been produced in this field alone as of April 2013. Additionally, activity targeting the deeper Wolfcamp formation increased dramatically after Henry Petroleum started drilling fully through the Wolfcamp formation in the early 2000s. In the late 2000s and early 2010s, many operators, including us, had success commingling still deeper production from the Upper Pennsylvanian (Cline), Strawn, and Atoka formations. Concurrently, operators started testing zones singularly with horizontal wells and multi-stage treatments. To date, the majority of these wells in the Midland Basin target the Upper Pennsylvanian and Wolfcamp formations. There have also been successful horizontal tests in the Clearfork, Spraberry, and Atoka formations.

Core Area Descriptions

We group our assets by area based on similar geologic, economic and technical requirements. We split our assets into four areas, the Midland Basin-Core, Midland Basin-Tier 1, Midland Basin-Other and Southern Delaware Basin.

Midland Basin-Core

Our Midland Basin-Core assets are characterized by being in the modern day sedimentary deep portion of the Midland Basin resulting in multiple stacked pay benches ranging from the Clearfork to the Atoka formations. Generally, well drilling and completion costs are slightly higher in the Midland Basin-Core area due to design for deeper depths and higher pressures. Our Midland Basin-Core contains the areas of Andrews, Glasscock, Howard, Martin, Midland, Reagan and Upton Counties.

As of December 31, 2014, we have 65,716 gross (42,564 net) acres in our Midland Basin-Core area. Approximately 73% of our acreage in this area is held by production. We have interests in 503 gross (288.8 net) producing wells in our Midland Basin-Core area as of December 31, 2014 and we operate 99% of the wells in which we have an interest. Since initiating our drilling program, we have drilled 362 wells in this area. The table below sets forth our identified drilling locations in the Midland Basin-Core as of December 31, 2014.

	Target Horizontal Locations					
	Short Laterals(1)		Long Laterals(1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Horizontal Zone						
Spraberry	68	52	14	11	82	63
Wolfcamp A	142	125	56	49	198	174
Wolfcamp B	133	120	70	63	203	183
Wolfcamp C	145	129	77	68	222	197
Upper Pennsylvanian (Cline)	176	157	80	71	256	228
Atoka	260	229	80	71	340	300
Total Target Horizontal Location	924	812	377	333	1,301	1,145

	Target Vertical Locations					
	80-and 40-Acre		20-Acre		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Vertical Locations	1,201	914	1,676	1,266	2,877	2,180
Total Target Horizontal and Vertical Locations					4,178	3,325

(1) Our target horizontal location count implies 660’ to 870’ between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

Midland Basin-Tier I

Our Midland Basin-Tier 1 assets are characterized by being in a shallower modern day sedimentary portion of the Midland Basin than our Midland Basin-Core. The southern boundary is the Big Lake Fault, the western boundary is the Central Basin Platform, the northern boundary is the Horseshoe Atoll and the Eastern boundary is the transition to the Eastern Shelf. Due to lower pressures and shallower depths, well drilling and completion costs tend to be slightly lower than the Midland Basin-Core. Our Midland Basin-Tier 1 includes areas of Andrews, Borden, Crane, Dawson, Ector, Glasscock, Howard, Irion, Martin, Midland, Reagan and Upton Counties.

As of December 31, 2014, we have 47,154 gross (36,289 net) acres in our Midland Basin-Tier I area. Approximately 68% of our acreage in this area is held by production. We have interests in 215 gross (125.4 net) producing wells in our Midland Basin-Tier I area as of December 31, 2014 and operate 99%, of the wells in which we have an interest. Since initiating our drilling program, we have drilled 160 wells in this area. The table below sets forth our identified drilling locations in the Midland Basin-Tier I as of December 31, 2014.

Midland Basin-Tier I (continued)

	Target Horizontal Locations					
	Short Laterals(1)		Long Laterals(1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Horizontal Zone						
Spraberry	96	79	13	11	109	90
Wolfcamp A	116	94	32	28	148	122
Wolfcamp B	114	92	30	26	144	118
Wolfcamp C	120	95	33	28	153	123
Upper Pennsylvanian (Cline)	109	89	32	29	141	118
Atoka	96	78	33	30	129	108
Total Target Horizontal Location	651	527	173	152	824	679

	Target Vertical Locations					
	80-and 40-Acre		20-Acre		Total	
	Gross	Net	Gross	Net	Gross	Net
Target Vertical Locations	583	437	636	477	1,219	914
Total Target Horizontal and Vertical Locations					2,043	1,593

(1) Our target horizontal location count implies 660’ to 870’ between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The ultimate spacing may be less than these amounts, which would result in a higher location count, or greater than these amounts, which would result in a lower location count.

Midland Basin-Other

Our Midland Basin-Other assets are characterized as assets that we have limited operating activity in which still fall within the Midland Basin. Over time, as our operating results dictate, we may reclassify these areas based on geologic, economic and technical results. Our Midland Basin-Other includes portions of Andrews, Dawson and Gaines Counties.

As of December 31, 2014, we have 31,832 gross (24,183 net) acres in our Midland Basin-Other area. None of our acreage in this area is held by production. We have interest in four gross (0.3 net) producing wells in our Midland Basin-Other area as of December 31, 2014. As of December 31, 2014, we have identified 109 gross 80- and 40- acre potential vertical locations and 91 gross 20- acre potential vertical drilling location on our properties in the Midland Basin-Other area. We have attributed no horizontal drilling locations at this time and no vertical locations to our leasehold position in Gaines County due to our limited operating history in the area. As our operating history and industry activity increases in the area, we expect to identify additional locations.

Delaware Basin

From the mid-Pennsylvanian period to the early Permian period, the Delaware Basin was a slowly subsiding area that was characterized by shallow marine shales and limestone. Influxes of clastic sands generally occurred as turbidite deposits formed during periodic sea-level changes. Records indicate a rapid deepening of the Delaware Basin relative to the emergent Central Basin Platform, during the early Permian period. Marine shale deposition continued to dominate the basin during this period. Episodic pulses of carbonate and clastic debris and density flows punctuated the shale deposition and eventually became significant reservoirs. Through the late Permian period, the basin became increasingly more clastic dominated as emergent shelf areas to the north shed sands into the basin.

As of December 31, 2014, our Delaware Basin acreage includes 83,109 Boe of proved developed reserves and two gross (two net) producing wells. We hold a leasehold position in 38,525 gross (30,238 net) acres in the Delaware Basin which we call our Trees Ranch Prospect. We believe our leasehold is prospective for Pennsylvanian aged production, based on historical shows and well tests in the Pennsylvanian and Permian (Wolfcamp) aged rocks on our leasehold. We commenced a three-well vertical appraisal program and completed two wells as of December 31, 2014. Upon further evaluating results, we will make a determination as to future development plans. Our Southern Delaware Basin assets are an area bounded on the East and Northeast by the Central Basin Platform, on the West by the Waha field and to the south by the Gomez field. This area is locally known as the Coyanosa Basin. Our Southern Delaware Basin includes portions of Pecos and Reeves Counties.

Production Status

For the year ended December 31, 2014, our average daily net production from our Midland Basin acreage, was 14,144 Boe/d, of which 49% was from oil and 51% was from natural gas and NGLs. Our average daily net production from our Delaware Basin acreage, was 63 Boe/d, of which 93% was from oil and 7% was from natural gas and NGLs. We had no production from the Central Basin Platform.

Facilities

Our land-based oil and gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations or centralized lease locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

During the year ended December 31, 2014, 149 gross (126 net) vertical wells were spud on our Midland Basin acreage for an aggregate estimated net cost of $284 million and 24 gross (19 net) horizontal wells were spud for aggregate estimated net cost of $140 million. Our capital budget for 2015 is approximately $225 million to $250 million. Our capital budget excludes any amounts that may be paid for acquisitions.

As of December 31, 2014, we have identified 1,893 80- and 40-acre potential vertical drilling locations, 2,403 20-acre potential vertical drilling locations and 2,125 potential horizontal drilling locations on our existing acreage, which does not include any vertical locations in our Gaines County (Midland Basin). Our target horizontal location count implies 660' to 870' between well spacing which is equivalent to five to eight wells per 640-acre section per prospective interval. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

Production and Price History

The following table sets forth information regarding our production of oil, natural gas and NGLs, and certain price and cost information, for the periods indicated:

	Year ended December 31,		
	2014	2013	2012
	(in thousands, except per share unit data)		
Average daily production volume:			
Oil (Bbls/d)	7,778	2,874	972
Natural gas and natural gas liquids (Mcf/d)	38,559	12,823	4,079
Total (Boe/d)	14,207	5,011	1,652
Average realized prices(1):			
Oil sales, without realized derivatives (per Bbls)	$ 81.91	$ 93.28	$ 85.60
Oil sales, with realized derivatives (per Bbls)	$ 81.33	$ 87.91	$ 83.08
Natural gas and NGLs, without realized derivatives (per Mcf)	$ 4.92	$ 4.95	$ 4.85
Natural gas and NGLs, with realized derivatives (per Mcf)	$ 4.96	$ 4.95	$ 4.85
Average price per BOE, without realized derivatives	$ 58.19	$ 66.17	$ 62.33
Average price per BOE, with realized derivatives	$ 58.00	$ 63.09	$ 60.85
Expense per Boe:			
Lease operating expenses	$ 7.34	$ 9.06	$ 7.69
Production and ad valorem taxes	$ 3.65	$ 3.87	$ 3.99
Depreciation, depletion and amortization	$ 18.18	$ 15.39	$ 10.60
General and administrative expenses	$ 6.75	$ 8.34	$ 6.00
Exploration costs	$ 0.60	$ —	$ —
Acquisition costs	$ 0.49	$ —	$ —
Incentive unit compensation	$ 9.85	$ 0.67	$ —
Stock based compensation	$ 0.43	$ —	$ —
Accretion of asset retirement obligations	$ 0.10	$ 0.10	$ 0.11
Total operating expenses per Boe	$ 47.39	$ 37.43	$ 28.39

Proved Reserves

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates as of December 31, 2014 and 2013 were prepared based on reports by NSAI, our independent petroleum engineers. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Matthew Gallagher, our Vice President—Chief Operating Officer, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Gallagher is a petroleum engineer with approximately ten years of reservoir and operations experience, and our engineering and geoscience staff have an average of approximately 11 years of industry experience per person.

The preparation of our historical proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by Mr. Gallagher or under his direct supervision;
- verification of property ownership by our land department.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2014 and December 31, 2013 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. The current pricing environment could impact future economics.

Under SEC rules, reasonable certainty can be established using techniques that have been proven 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. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Summary of Oil, NGLs, and Natural Gas Reserves. The following table presents our estimated net proved oil, NGLs, and natural gas reserves as of the periods indicated:

	December 31,	
	2014	2013
Proved developed reserves:		
Oil (MBbls)	23,547	13,560
NGLs (MBbls)	11,491	4,762
Natural gas (MMcf)	65,484	31,301
Combined (MBoe)(1)	45,952	23,539
Proved undeveloped reserves:		
Oil (MBbls)	24,070	15,947
NGLs (MBbls)	11,175	7,595
Natural gas (MMcf)	58,161	46,517
Combined (MBoe)(1)	44,939	31,295
Proved reserves:		
Oil (MBbls)	47,617	29,507
NGLs (MBbls)	22,667	12,357
Natural gas (MMcf)	123,645	77,818
Combined (MBoe)(1)	90,891	54,834

(1) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Item 1A. Risk Factors."

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this annual report and the proved reserve report as of December 31, 2014, which is included in this annual report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2014, our proved undeveloped reserves were composed of 24,070 MBbls of oil, 11,175 MBbls of NGLs, and 58,161 MMcf of natural gas for a total of 44,939 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during the year ended December 31, 2014 (in MBoe):

Balance, December 31, 2013	31,295
Purchases of reserves	10,677
Extensions and discoveries	19,256
Revisions of previous estimates	(9,439)
Transfers to proved developed	(6,850)
Balance, December 31, 2014	44,939

Extensions and discoveries of 19,256 MBoe during the year ended December 31, 2014, resulted primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year.

Costs incurred relating to the development of locations that were classified as PUDs at December 31, 2013 were $292.8 million during the year ended December 31, 2014. Additionally, during 2014 we spent approximately $189.0 million drilling and completing other in-field wells which were not classified as PUDs as of December 31, 2013. Estimated future development costs relating to the development of PUDs at December 31, 2014 were projected to be approximately $34.0 million in the year ended December 31, 2015, $325.9 million in 2016, $100.5 million in 2017, $90.7 million in 2018 and $76.3 million in 2019. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking.

As of December 31, 2014, less than 1% of our total proved reserves were classified as proved developed non-producing.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2014 relating to our leasehold acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

As of December 31, 2014

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
Area	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
Midland Basin	61,964	36,817	82,738	66,219	144,702	103,036
Delaware Basin	240	240	38,285	29,998	38,525	30,238
Total	62,204	37,057	121,023	96,217	183,227	133,274

(1) Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.

(2) Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. All of the leases governing our acreage have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 60 to 180 days of the expiration date, without the requirement of a lease extension payment. Thereafter, the lease is held with additional development every 60 to 180 days until the entire lease is held by production. None of our vertical drilling locations associated with proved undeveloped reserves are scheduled for drilling outside of a lease term that is not accounted for with a continuous development schedule. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2014, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2015		2016		2017		2018		2019	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	12,922	9,230	26,612	19,859	9,698	8,588	13,413	13,413	1,944	963
Delaware Basin	33,672	27,819	4,613	2,179	—	—	—	—	—	—
Total	46,594	37,049	31,225	22,038	9,698	8,588	13,413	13,413	1,944	963

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Horizontal:						
Development Wells:						
Productive(1)	18	13	—	—	—	—
Dry holes	—	—	—	—	—	—
Vertical:						
Development Wells:						
Productive(1)	168	137	170	100	89	34
Dry holes	—	—	1	1	1	1
Exploratory Wells:						
Productive(1)	2	2	—	—	—	—
Dry holes	—	—	—	—	—	—
Total:						
Productive(1)	188	152	170	100	89	34
Dry holes	—	—	1	1	1	1
	188	152	171	101	90	35

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

As of December 31, 2014 we had one gross (0.8 net) vertical wells in the process of drilling, one gross (0.8 net) vertical wells awaiting hydraulic fracturing procedures, and two gross (1.8 net) vertical wells in the process of being completed that are not reflected in the above table. In addition, we had four gross (3.5 net) horizontal wells in the process of drilling, two gross (1.2 net) horizontal wells awaiting hydraulic fracturing procedures, and two gross (1.6 net) horizontal wells in the process of being completed that are not reflected in the above table.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this annual report.

Facilities

Our corporate headquarters is located in Austin, Texas with field operation facilities in Midland, Texas. We believe that our facilities are adequate for our current operations.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment-related disputes. We do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common stock began trading on the NYSE under the symbol "PE" on May 29, 2014. Prior to that, there was no public market for our common stock. The following table sets forth high and low sales prices of our common stock for the periods indicated:

	High	Low
2014		
Quarter ended December 31	$ 21.03	$ 11.26
Quarter ended September 30	$ 23.95	$ 19.89
Quarter ended June 30(a)	$ 25.16	$ 22.11

(a) Represents the period from May 29, 2014, the date on which our common stock began trading on the NYSE, through June 30, 2014.

On March 10, 2015, the closing sales price of our common stock as reported by the NYSE was $14.31 per share and we had approximately 77 stockholders of record. This number does not include owners for whom shares of common stock may be held in "street" name.

Dividends

We have never declared or paid any cash dividends to holders of our common stock. We currently intend to retain all available funds, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our results of operations, financial condition, capital requirements, and investment opportunities. In addition, our debt agreements restrict our ability to pay cash dividends to holders of our common stock.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

We did not purchase any shares of our Class A Common Stock or Class B Common Stock during the quarter or fiscal year ended December 31, 2014.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the quarter or fiscal year ended December 31, 2014.

Subscription Agreement

On February 5, 2015, we entered into a subscription agreement with certain institutional investors pursuant to which the purchasers agreed to purchase 14,885,797 shares of our Class A Common Stock in a private placement at a price of $15.50 per share. The issuance of the shares pursuant to the subscription agreement was made in reliance upon an exemption from registration provided under Section 4(2) of the Securities Act.

The Private Placement closed on February 11, 2015. The Private Placement resulted in approximately $231 million of gross proceeds and approximately $224 million of net proceeds (after deducting placement agent commissions and the Company's expenses). We used the net proceeds of the Private Placement to repay a portion of outstanding borrowings under our Revolving Credit Agreement and for general corporate purposes.

The foregoing is qualified in its entirety by reference to the Subscription Agreement, a copy of which is herein incorporated by reference as Exhibit 10.37.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected historical financial data for the periods and as of the periods indicated. The following selected consolidated and combined financial and operating data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data":

	Year ended December 31,		
	2014	2013	2012
	(in thousands, except per share unit data)		
REVENUES (1)			
Oil	$ 232,554	$ 97,839	$ 30,443
Natural gas and natural gas liquids sales	69,203	23,179	7,236
Total revenues	301,757	121,018	37,679
OPERATING EXPENSES			
Lease operating expenses	38,071	16,572	4,646
Production and ad valorem taxes	18,941	7,081	2,412
Depreciation, depletion and amortization	94,297	28,152	6,406
General and administrative expenses	34,997	15,248	3,629
Exploration costs	3,136	—	—
Acquisition costs	2,527	—	—
Incentive unit compensation	51,088	1,233	—
Stock based compensation	2,209	—	—
Accretion of asset retirement obligations	512	181	66
Total operating expenses	245,778	68,467	17,159
(Loss) gain on sale of property	(2,097)	36	7,819
OPERATING INCOME	53,882	52,587	28,339
OTHER INCOME (EXPENSE)			
Interest expense, net	(38,607)	(13,714)	(6,285)
Rig termination	(765)	—	—
Prepayment premium on extinguishment of debt	(5,107)	—	(6,597)
Income from equity investment	348	184	267
Derivative income (loss)	83,858	(9,800)	(2,190)
Other income (expense)	(419)	159	(81)
Total other income (expense), net	39,308	(23,171)	(14,886)
INCOME BEFORE INCOME TAXES	93,190	29,416	13,453
INCOME TAX EXPENSE (2)	(36,468)	(1,906)	(554)
NET INCOME	56,722	27,510	12,899
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(33,293)	—	—
NET INCOME ATTRIBUTABLE TO PARSLEY ENERGY INC. STOCKHOLDERS	$ 23,429	$ 27,510	$ 12,899
Net income per common share:			
Basic	$ 0.42		
Diluted	$ 0.42		
Weighted average common shares outstanding:			
Basic	55,136		
Diluted	55,239		
Total Production Volumes			
Oil (MBbls)	2,839	1,049	356
Natural Gas and NGLs (MMcf)	14,074	4,680	1,493
Combined (MBoe)	5,186	1,829	604

(1) There were multiple significant acquisitions during 2014 and 2013 which affect the comparability of the oil and natural gas revenues.

(2) Parsley Energy, Inc. is a subchapter C corporation ("C-Corp") under the Internal Revenue Code of 1986, as amended, and is subject to federal and State of Texas income taxes. Our predecessor, Parsley LLC was not subject to U.S. federal income taxes. As a result, the consolidated and combined net income in our historical financial statements for periods prior to our May 29, 2014 IPO does not reflect the tax expense we would have incurred as a C-Corp during such periods.

	Year ended December 31,		
	2014	2013	2012
	(in thousands, except per share unit data)		
Average daily production volume:			
Oil (Bbls/d)	7,778	2,874	972
Natural gas and natural gas liquids (Mcf/d)	38,559	12,823	4,079
Total (Boe/d)	14,207	5,011	1,652
Average realized prices:			
Oil sales, without realized derivatives (per Bbls)	$ 81.91	$ 93.28	$ 85.60
Oil sales, with realized derivatives (per Bbls)	$ 81.33	$ 87.91	$ 83.08
Natural gas and NGLs, without realized derivatives (per Mcf)	$ 4.92	$ 4.95	$ 4.85
Natural gas and NGLs, with realized derivatives (per Mcf)	$ 4.96	$ 4.95	$ 4.85
Average price per BOE, without realized derivatives	$ 58.19	$ 66.17	$ 62.33
Average price per BOE, with realized derivatives	$ 58.00	$ 63.09	$ 60.85
Expense per Boe:			
Lease operating expenses	$ 7.34	$ 9.06	$ 7.69
Production and ad valorem taxes	$ 3.65	$ 3.87	$ 3.99
Depreciation, depletion and amortization	$ 18.18	$ 15.39	$ 10.60
General and administrative expenses	$ 6.75	$ 8.34	$ 6.00
Exploration costs	$ 0.60	$ —	$ —
Acquisition costs	$ 0.49	$ —	$ —
Incentive unit compensation	$ 9.85	$ 0.67	$ —
Stock based compensation	$ 0.43	$ —	$ —
Accretion of asset retirement obligations	$ 0.10	$ 0.10	$ 0.11
Total operating expenses per Boe	$ 47.39	$ 37.43	$ 28.39
Consolidated Statements of Cash Flows Data:			
Net cash provided by (used in):			
Operating activities	$ 184,983	$ 53,235	$ 5,025
Investing activities	(1,247,677)	(425,611)	(89,539)
Financing activities	1,093,851	378,096	74,245
Proved reserves:			
Oil (MBbls)	47,617	29,507	12,987
Natural gas (MMcf)	22,667	12,357	4,732
NGLs (MBbls)	123,645	77,818	30,214
Combined (MBoe)	90,891	54,834	22,755
Consolidated Balance Sheet Data:			
Cash and cash equivalents	$ 50,550	$ 19,393	$ 13,673
Total assets	2,051,079	742,556	181,239
Long-term debt	676,845	429,970	112,913
Total equity	992,489	108,032	6,017
Other Financial Data:			
Adjusted EBITDA (1)	206,060	76,828	26,281

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation to our most directly comparable financial measures calculated and presented in accordance with GAAP, please read "— Non-GAAP Financial Measures."

Non-GAAP Financial Measures

Adjusted EBITDA

Adjusted EBITDA is not a measure of net income as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated and combined financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income before depreciation, depletion and amortization, exploration costs, acquisition costs, gain (loss) on sales of oil and natural gas properties, asset retirement obligation accretion expense, non-cash stock based compensation, incentive unit expense, interest expense, income tax, rig termination, prepayment premium on extinguishment of debt, gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments and premiums (paid) received on options that settled during the period.

Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following table presents a reconciliation of Adjusted EBITDA to the GAAP financial measure of net income for each of the periods indicated.

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Adjusted EBITDA reconciliation to net income:			
Net income attributable to Parsley Energy, Inc. stockholders'	$ 23,429	$ 27,510	$ 12,899
Net income attributable to noncontrolling interests	33,293	—	—
Depreciation, depletion and amortization	94,297	28,152	6,406
Exploration costs	3,136	—	—
Acquisition costs	2,527	—	—
Loss (gain) on sales of oil and natural gas properties	2,097	(36)	(7,819)
Asset retirement obligation accretion expense	512	181	66
Non-cash stock based compensation	2,209	—	—
Incentive unit compensation	51,088	1,233	—
Interest expense, net	38,607	13,714	6,285
Income tax	36,468	1,906	554
Rig termination	765	—	—
Prepayment premium on extinguishment of debt	5,107	—	6,597
Derivative (income) loss	(83,858)	9,800	2,190
Net cash receipts (payments) on settled derivative instruments	3,311	(198)	179
Premiums (paid) received on options that settled during the period	(6,928)	(5,434)	(1,076)
Adjusted EBITDA	$ 206,060	$ 76,828	$ 26,281

PV-10

The following table provides a reconciliation of PV-10 to the GAAP financial measure of Standardized Measure as of December 31, 2014:

	As of December 31, 2014
	(in millions)
PV-10 of proved reserves	$ 1,314.0
Present value of future income tax discounted at 10%	(359.0)
Standardized Measure	$ 955.0

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this annual report, particularly in "Item 1A. Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Our Predecessor and Parsley Energy, Inc.

We were formed in December 2013 and do not have historical financial operating results. For purposes of this annual report, our accounting predecessors are Parsley LLC and its predecessors. Parsley LLC was formed in June 2013 to engage in the acquisition, development, exploration and exploitation of oil and natural gas reserves in the Permian Basin. Concurrent with the formation of Parsley LLC, all of the interest holders in Parsley Energy, L.P., Parsley Energy Management, LLC, and Parsley Energy Operations, LLC exchanged their interests in each such entity for interests in Parsley LLC (the "Exchange"). The Exchange was treated as a reorganization of entities under common control.

We are a holding company whose sole material asset consists of 32,145,296 units in Parsley LLC. We are the managing member of Parsley LLC and are responsible for all operational, management and administrative decisions of Parsley LLC, and we consolidate the financial results of Parsley LLC and its subsidiaries.

Basis of Presentation

We consider and report all of our operations as one segment.

Overview

We are an independent oil and natural gas company focused on the acquisition, development and exploitation of unconventional oil and natural gas reserves in the Permian Basin. Our properties are located in the Midland and Delaware Basins and our activities have historically been focused on the vertical development of the Spraberry, Wolfberry and Wolftoka Trends of the Midland Basin. Our vertical wells in the area are drilled into stacked pay zones that include the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline), Strawn, Atoka and Mississippian formations. During the course of 2014 we transitioned from primarily vertical development drilling to predominantly horizontal drilling development activity.

Our Properties

At December 31, 2014, our acreage position was 133,274 net acres. The vast majority of our acreage is located in the Midland Basin, and the majority of our identified vertical and horizontal drilling locations are located in our Midland Basin-Core area. Our Midland Basin-Core area contains areas of Andrews, Glasscock, Howard, Martin, Midland, Reagan, and Upton Counties. From the time we began drilling operations in November 2009 through December 31, 2014, we have drilled and placed on production approximately 524 vertical wells across our acreage in the Midland Basin. In addition to our vertical drilling program in the Midland Basin, we initiated our horizontal development program with one rig during the fourth quarter of 2013 and have increased to five operated horizontal rigs as of December 31, 2014. Through December 31, 2014, we have drilled and placed on production 18 horizontal wells in the Midland Basin. Additionally, we commenced our vertical appraisal drilling program in the Delaware Basin during the first quarter of 2014. At December 31, 2014, we had drilled and completed two vertical appraisal wells. As of December 31, 2014, we have identified 2,125 potential horizontal drilling locations, 1,893 80- and 40-acre potential vertical drilling locations and 2,403 20-acre potential vertical drilling locations on our existing acreage, which does not include any locations in Gaines County (Midland Basin) or in our Southern Delaware Basin acreage. As of December 31, 2014, we had interests in 724 gross (416.4 net) producing wells across our properties and operated 99% of the wells in which we had an interest.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures; and
- Adjusted EBITDA.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the year ended December 31, 2014 and 2013, our revenues were derived 77% and 81%, respectively, from oil sales and 23% and 19%, respectively, from natural gas and NGLs sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. NGLs production and sales are included in our natural gas production and sales.

Production Volumes

The following table presents historical production volumes for our properties for the years ended December 31, 2014, 2013, and 2012.

	Year Ended December 31,		
	2014	**2013**	**2012**
Oil (MBbls)	2,839	1,049	356
Natural gas and natural gas liquid (MMcf)	14,074	4,680	1,493
Total (MBoe)	5,186	1,829	604
Average net production (Boe/d)	14,207	5,011	1,652

Production volumes directly impact our results of operations.

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic drill-bit growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry and Our Business” for a discussion of these and other risks affecting our proved reserves and production.

Realized Prices on the Sale of Oil, Natural Gas and NGLs

The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the Cushing, Oklahoma transport hub and the Gulf Coast refineries. Periodically, logistical and infrastructure constraints at the Cushing, Oklahoma transport hub have resulted in an oversupply of crude oil at Midland, Texas and thus lower prices for Midland WTI. These lower prices have adversely affected the prices we realize on oil sales and increased our differential to NYMEX WTI.

The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas’ proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil and natural gas normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, respectively.

	Year Ended December 31,		
	2014	2013	2012
Oil			
NYMEX WTI High	$ 107.26	$ 110.53	$ 109.77
NYMEX WTI Low	$ 53.61	$ 86.68	$ 77.69
Differential to Average NYMEX WTI	$ 1.47	$ (5.33)	$ (8.13)
Natural Gas			
NYMEX Henry Hub High	$ 6.15	$ 4.46	$ 3.90
NYMEX Henry Hub Low	$ 3.01	$ 3.11	$ 1.91
Differential to Average NYMEX Henry Hub	$ 0.34	$ 1.16	$ (2.81)

Because our NGLs are reported in our natural gas revenue, our differential to NYMEX Henry Hub is positive.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2014, the NYMEX-WTI oil price ranged from a high of $107.26 per Bbl to a low of $53.61 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.15 per MMBtu to a low of $3.01 per MMBtu. Further, during the three years ended December 31, 2014, 2013, and 2012, the NYMEX-WTI oil price ranged from a high of $110.53 per Bbl to a low of $53.61 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.15 per MMBtu to a low of $1.91 per MMBtu.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil production. By removing a significant portion of price volatility associated with our oil production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will sustain gains to the extent our derivatives contract prices are higher than market prices. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk” for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis including hedging our natural gas production. We are not under an obligation to hedge a specific portion of our oil or natural gas production.

Our positions hedging production as of December 31, 2014 were as follows:

Description and Production Period	VOLUME (Bbls)	SHORT PUT PRICE ($/Bbl)	LONG PUT PRICE ($/Bbl)	SHORT CALL PRICE ($/Bbl)
Crude Oil Put Spreads:				
January 2015 - June 2015	120,000	$ 60.00	$ 85.00	
January 2015 - September 2015	630,000	$ 55.00	$ 72.50	
February 2015 - June 2015	500,000	$ 60.00	$ 80.00	
July 2015 - September 2015	75,000	$ 70.00	$ 85.00	
July 2015 - September 2015	75,000	$ 65.00	$ 85.00	
July 2015 - February 2016	960,000	$ 40.00	$ 55.00	
October 2015 - June 2016	540,000	$ 60.00	$ 80.00	
October 2015 - December 2016	2,325,000	$ 40.00	$ 55.00	
March 2016 - December 2016	1,150,000	$ 40.00	$ 55.00	
July 2016 - December 2016	450,000	$ 40.00	$ 55.00	
July 2016 - December 2016	450,000	$ 70.00	$ 85.00	
Crude Oil Three Way Collars:				
January 2015	100,000	$ 55.00	$ 87.50	$ 120.00
January 2015 - September 2015	360,000	$ 65.00	$ 80.00	$ 110.00
January 2015 - February 2016	490,000	$ 65.00	$ 85.00	$ 110.00
March 2015 - June 2016	600,000	$ 65.00	$ 85.00	$ 120.00
July 2016 - December 2016	255,000	$ 60.00	$ 80.00	$ 115.00
January 2017 - June 2017	600,000	$ 60.00	$ 80.00	$ 115.00

Description and Production Period	VOLUME (MBtu)	SHORT PUT PRICE ($/MMBtu)	LONG PUT PRICE ($/MMBtu)	SHORT CALL PRICE ($/MMBtu)
Natural Gas Three Way Collars:				
February 2015 - December 2015	3,300,000	$ 3.75	$ 4.50	$ 5.25

During the fourth quarter 2014, Parsley elected to lower certain strike prices for both long and short put positions. The Company primarily focused on positions in late 2015 and 2016. In lowering the strike prices for the put spreads, the Company collected approximately $45.5 million of cash which is reflected in our year-end cash balance.

The Company excluded from the table above 6,700 notional MBbls with a fair value of $144.9 million relating to amounts recognized under the master netting agreement with the derivative counterparty.

Principal Components of Our Cost Structure

Lease Operating Expenses. Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water injection and disposal, utilities, materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative expenses or production or ad valorem taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased lease operating expenses in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production.

We monitor our operations to ensure that we are incurring lease operating expenses at an acceptable level. For example, we monitor our lease operating expenses per Boe to determine if any wells or properties should be shut in, recompleted or sold. This unit rate also allows us to monitor these costs in certain fields and geographic areas to identify trends and to assess our lease operating expenses in comparison to other producers. Although we strive to reduce our lease operating expenses, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or make acquisitions and dispositions of properties. For example, we may increase field level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another or we may acquire or dispose of properties that have different lease operating expenses per Boe. These initiatives would influence our overall operating cost and could cause fluctuations when comparing lease operating expenses on a period to period basis. In addition, since most of our wells were completed relatively recently, they are currently producing at high rates. As with all wells, however, over time production will decrease, which will result in an increase in our lease operating expenses on a per barrel basis. We also expect an increase in our lease operating expenses as we increase the number of wells drilled and operated.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

Depletion, Depreciation and Amortization. Depreciation, depletion and amortization ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, which are then allocated to each unit of production using the unit of production method. Please read "—Critical Accounting Policies and Estimates—Successful Efforts Method of Accounting for Oil and Natural Gas Activities" for further discussion.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, amortization and impairment of unproved leasehold costs, and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete.

General and Administrative Expenses. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations including numerous software applications, audit and other fees for professional services and legal compliance. Also included as compensation expense are amounts required to be recognized attributable to issued and outstanding incentive units. See "—Factors Affecting the Comparability of Our Financial Condition and Results of Operations."

Derivative Gain (Loss). We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of oil. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future oil prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Interest Expense. We finance a portion of our working capital requirements and capital expenditures with borrowings under our Revolving Credit Agreement and second lien credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our Revolving Credit Agreement and second lien credit facility in interest expense. Interest expense also includes the PIK interest on the second lien credit facility and our prior mezzanine debt facility.

Adjusted EBITDA

We define Adjusted EBITDA as net income before depreciation, depletion and amortization, exploration costs, acquisition costs, gain (loss) on sales of oil and natural gas properties, asset retirement obligation accretion expense, non-cash stock based compensation, incentive unit expense, interest expense, income tax, rig termination, prepayment premium on extinguishment of debt, gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments and premiums (paid) received on options that settled during the period.

Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements. For further discussion, please read "Selected Financial Data—Non-GAAP Financial Measures."

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Incentive Unit Compensation. For the year ended December 31, 2014 and the year ended December 31, 2013, within Incentive unit compensation, are amounts attributable to incentive units that, pursuant to the terms of the Parsley LLC limited liability company agreement at that date, were only entitled to a payout after a specified level of cumulative cash distributions had been received by Natural Gas Partners, through NGP and other investors, including all of our executive officers. At December 31, 2013 and December 31, 2014, the incentive units were being accounted for as liability-classified awards pursuant to ASC Topic 718, "Compensation—Stock Compensation", as achievement of the payout conditions required settlement of such awards by transferring cash to the incentive unit holder.

As part of the transactions described below under "—Corporate Reorganization," the Parsley LLC limited liability company agreement was amended. Such amendments, among other things, converted all outstanding incentive units in Parsley LLC into PE Units. A portion of such PE Units were exchanged on a one for one basis for shares of Class A Common Stock, instead of in cash. As a result, on May 29, 2014, we accounted for the incentive unit awards as equity-classified awards pursuant to ASC Topic 718. This resulted in the recognition of $50.6 million of stock based compensation equal to the excess of the modified awards' fair value (based on the initial offering price of $18.50) over the amount of cumulative compensation cost recognized prior to that date.

Stock Based Compensation. Restricted stock awards are awards of Class A Common Stock that are subject to restrictions on transfer and to a risk of forfeiture if the award recipient is no longer an employee or director of the Company for any reason prior to the lapse of the restrictions. Restricted stock unit awards are awards of restricted stock units that are subject to restrictions on transfer and to a risk of forfeiture if the award recipient is no longer an employee or director of the Company for any reason prior to the lapse of the restriction. Each restricted stock unit represents the right to receive one share of Class A Common Stock. The fair value of such awards was determined using the weighted average closing price on the grant date and compensation expense is recorded over the applicable vesting periods. During the year ended December 31, 2014, 769,694 shares of restricted stock and 23,649 restricted stock units were granted to our directors, management, and employees. During the year ended December 31, 2014, 36,739 shares were forfeited. Stock based compensation expense related to restricted stock and restricted stock units was $2.2 million for year ended December 31, 2014. There was approximately $11.8 million of unamortized stock compensation expense relating to outstanding restricted stock and restricted stock units at December 31, 2014.

Public Company Expenses. We expect to incur direct, incremental general and administrative expenses as a result of being a publicly traded company, including, but not limited to, increased scope of our operations as a result of recent activities and costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental general and administrative expenses are not included in our historical results of operations.

Corporate Reorganization. The historical consolidated and combined financial statements included in this annual report are based on the financial statements of our accounting predecessors, Parsley LLC and its predecessors, prior to the reorganization that occurred in connection with our IPO as described in *Note 1—Organization and Nature of Operations – Corporate Reorganization* of our consolidated and combined financial statements for the year ended December 31, 2014 included elsewhere in this annual report. As a result, the historical consolidated and combined financial data may not give you an accurate indication of what our actual results would have been if the transactions described in *Note 1—Organization and Nature of Operations – Corporate Reorganization* of our consolidated and combined financial statements for the year ended December 31, 2014 included elsewhere in this annual report had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. In addition, we have entered into the TRA with the TRA Holders in connection with our IPO. This agreement generally provides for the payment by us to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of (i) any tax basis increases resulting from the contribution in connection with our IPO by such TRA Holder of all or a portion of its PE Units to the Company in exchange for shares of Class A Common Stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A Common Stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash at our or Parsley LLC's election) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. We will retain the benefit of the remaining 15% of these cash savings.

Income Taxes. Our accounting predecessors are limited liability companies or limited partnerships and therefore not subject to U.S. federal income taxes. Accordingly, no provision for U.S. federal income tax has been provided for in our historical results of operations. We are taxed as a corporation under the Internal Revenue Code and subject to U.S. federal income tax at a statutory rate of 35% of pretax earnings, and, as such, the amount of our future U.S. federal income tax will be dependent upon our future taxable income.

Our operations located in Texas are subject to an entity-level tax, the Texas margin tax, at a statutory rate of up to 1.0% of Texas income.

Increased Drilling Activity. We began drilling operations in November 2009. As of December 31, 2014, we operated five horizontal drilling rigs and one vertical drilling rig on our properties. For the year ended December 31, 2014, our capital expenditures for drilling and completions were $491.3 million, as compared to $268.4 million for all of fiscal year 2013.

The amount and timing of our future capital expenditures is largely discretionary and within our control. We could choose to defer a portion of planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Results of Operations

Year ended December 31, 2014 Compared to Year ended December 31, 2013

Oil and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Year Ended December 31, 2014	Year Ended December 31, 2013	$ Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$ 232,554	$ 97,839	$ 134,715	138%
Natural gas and natural gas liquid sales	69,203	23,179	46,024	199%
Total revenues	$ 301,757	$ 121,018	$ 180,739	149%
Average realized prices(1):				
Oil sales, without realized derivatives (per Bbls)	$ 81.91	$ 93.28	$ (11.37)	(12)%
Oil sales, with realized derivatives (per Bbls)	$ 81.33	$ 87.91	$ (6.58)	(7)%
Natural gas and NGLs, without realized derivatives (per Mcf)	$ 4.92	$ 4.95	$ (0.03)	(1)%
Natural gas and NGLs, with realized derivatives (per Mcf)	$ 4.96	$ 4.95	$ 0.01	0%
Average price per BOE, without realized derivatives	$ 58.19	$ 66.17	$ (7.98)	(12)%
Average price per BOE, with realized derivatives	$ 58.00	$ 63.09	$ (5.09)	(8)%
Production:				
Oil (MBbls)	2,839	1,049	1,790	171%
Natural gas and natural gas liquid (MMcf)	14,074	4,680	9,394	201%
Total (MBoe)(2)	5,186	1,829	3,357	184%
Average daily production volume:				
Oil (Bbls/d)	7,778	2,874	4,904	171%
Natural gas and natural gas liquids (Mcf/d)	38,559	12,823	25,736	201%
Total (Boe/d)	14,207	5,011	9,196	184%

(1) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

(2) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the years indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2014	2013
Average realized oil price ($/Bbl)	$ 81.91	$ 93.28
Average NYMEX ($/Bbl)	$ 80.44	$ 98.61
Differential to NYMEX	$ 1.47	$ (5.33)
Average realized oil price to NYMEX percentage	102%	95%
Average realized natural gas price ($/Mcf)	$ 4.92	$ 4.95
Average NYMEX ($/Mcf)	$ 4.58	$ 3.79
Differential to NYMEX	$ 0.34	$ 1.16
Average realized natural gas to NYMEX percentage	107%	131%

Oil revenues increased 138% to $232.6 million during the year ended December 31, 2014 from $97.8 million during the year ended December 31, 2013. The increase is attributable to an increase in oil production volumes of 1,790 MBbls offset by a decrease in average oil prices to $81.91 per barrel from $93.28 per barrel. Of the overall changes in oil sales, increases in oil production volumes accounted for a positive change of $167.0 million, offset by the decrease in oil prices, which accounted for a negative change of $32.3 million.

Natural gas and NGLs revenues increased 199% to $69.2 million during the year ended December 31, 2014 from $23.2 million during the year ended December 31, 2013. The increase is attributable to an increase in volumes sold of 9,394 MMcf offset by a decrease in average natural gas prices to $4.92 per Mcf from $4.95 per Mcf. Of the overall changes in natural gas and NGLs, increases in natural gas and NGLs production volumes accounted for a positive change of $46.5 million while decreases in prices accounted for a negative change of $0.5 million. Natural gas revenue includes revenue from the sale of NGLs volumes.

Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Year ended December 31,			
	2014	2013	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$ 38,071	$ 16,572	$ 21,499	130%
Production and ad valorem taxes	18,941	7,081	11,860	167%
Depreciation, depletion and amortization	94,297	28,152	66,145	235%
General and administrative expenses	34,997	15,248	19,749	130%
Exploration costs	3,136	—	3,136	100%
Acquisition costs	2,527	—	2,527	100%
Incentive unit compensation	51,088	1,233	49,855	4,043%
Stock based compensation	2,209	—	2,209	100%
Accretion of asset retirement obligations	512	181	331	183%
Total operating expenses	$ 245,778	$ 68,467	$ 177,311	259%
Expense per Boe:				
Lease operating expenses	$ 7.34	$ 9.06	$ (1.72)	(19)%
Production and ad valorem taxes	3.65	3.87	(0.22)	(6)%
Depreciation, depletion and amortization	18.18	15.39	2.79	18%
General and administrative expenses	6.75	8.34	(1.59)	(19)%
Exploration costs	0.60	—	0.60	100%
Acquisition costs	0.49	—	0.49	100%
Incentive unit compensation	9.85	0.67	9.18	1,370%
Stock based compensation	0.43	—	0.43	100%
Accretion of asset retirement obligations	0.10	0.10	—	—%
Total operating expenses per Boe	$ 47.39	$ 37.43	$ 9.96	27%

Lease Operating Expenses. Lease operating expenses increased 130% to $38.1 million during the year ended December 31, 2014 from $16.6 million during the year ended December 31, 2013. The increase is primarily due to the higher operated well count during the year ended December 31, 2014 as compared to the prior year period. On a per Boe basis, lease operating expenses decreased to $7.34 per Boe from $9.06 per Boe. This decrease was attributable to higher initial production from new wells which lower our average price, partially offset by an increase in costs for workovers, repairs and maintenance, and additional lease operators.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 167% to $18.9 million during the year ended December 31, 2014 from $7.1 million during the year ended December 31, 2013 due to increased wellhead revenue resulting from higher production. Our increased drilling activity led to a higher number of wells brought on production during the year ended December 31, 2014 compared to the year ended December 31, 2013.

Depreciation, Depletion and Amortization. DD&A expense increased by 235% to $94.3 million for the year ended December 31, 2014 from $28.2 million during the year ended December 31, 2013 due to an increase in capitalized costs and production volumes. DD&A expense per BOE for the year ended December 31, 2014 increased by $2.79 from the year ended December 31, 2013 primarily due to the multiple oil and gas acquisitions and the increase in developmental costs.

General and Administrative Expenses. General and administrative expenses increased 130% to $35.0 million during the year ended December 31, 2014 from $15.2 million during the year ended December 31, 2013 primarily due to higher payroll and payroll-related costs as we added additional employees to manage our growing asset base, higher rig count, and increased production.

Exploration Costs. Exploration costs incurred during the year ended December 31, 2014 are comprised of $2.4 million of geological and geophysical expenses, which primarily consist of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to our Delaware Basin area. Exploration costs also include $0.7 million of non-cash leasehold impairment expense, of which $0.3 million is related to the amortization of unproved properties and $0.4 million is related to future leasehold expirations. No exploration costs were incurred during the year ended December 31, 2013.

Acquisition Costs. Acquisition costs during the year ended December 31, 2014 are due to a one time advisory and valuation fee related to the Cimarex Acquisition, as described in *Note 6—Acquisitions of Oil and Gas Properties* of our consolidated and combined financial statements for the year ended December 31, 2014 included elsewhere in this annual report. No acquisition costs were incurred during the year ended December 31, 2013.

Incentive Unit Compensation. Incentive unit compensation increased $49.9 million to $51.1 million during the year ended December 31, 2014 from $1.2 million during the year ended December 31, 2013 due to the one time incentive unit compensation expense recognized upon the corporate reorganization. No incentive unit compensation expenses were incurred during the year ended December 31, 2013.

Stock Based Compensation. Stock based compensation increased $2.2 million for the year ended December 31, 2014 due to the issuance and amortization of the restricted stock and restricted stock units issued during the year ended December 31, 2014. No stock based compensation expenses were incurred during the year ended December 31, 2013.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Year ended December 31,			
	2014	2013	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Interest expense, net	$ (38,607)	$ (13,714)	$ (24,893)	182%
Rig termination	(765)	—	(765)	(100)%
Prepayment premium paid on extinguishment of debt	(5,107)	—	(5,107)	(100)%
Income from equity investment	348	184	164	89%
Derivative income (loss)	83,858	(9,800)	93,658	956%
Other income (expense)	(419)	159	(578)	(364)%
Total other expense, net	$ 39,308	$ (23,171)	$ 62,479	(270)%

Interest Expense. Interest expense increased 182% to $38.6 million in the year ended December 31, 2014 from $13.7 million during the year ended December 31, 2013 primarily due to higher weighted-average outstanding borrowings under our credit facilities and accrued interest under our Senior Notes due 2022 (the "Notes").

Rig Termination. During the fourth quarter of 2014, we paid a total of $0.4 million in rig termination expenses in connection with the early termination of one drilling rig contract entered into in 2014 and $0.4 million in rig termination expenses for stacking fees associated with three drilling rig contracts. No rig termination expenses were incurred during the year ended December 31, 2013.

Prepayment Premium on Extinguishment of Debt. During the first quarter of 2014, we incurred a $5.1 million charge related to a prepayment penalty on our then outstanding second lien term loan. No similar expenses were incurred during the year ended December 31, 2013.

Derivative Income (Loss). Income from derivative instruments increased $93.7 million during the year ended December 31, 2014 to $83.9 million during the year ended December 31, 2014 from a loss of $9.8 million during the year ended December 31, 2013, primarily as a result of the impact of unfavorable commodity price changes on increased hedging activities.

Gain on Sales of Oil and Natural Gas Properties

In August of 2014, we sold our interest in one operated well and 38 net acres for total proceeds of $0.2 million and realized a $2.1 million loss on the sale.

In August 2013, we sold our interest in seven non-operated wells and 190 net acres for total proceeds of $0.8 million and realized a $36,000 gain on the sale.

Income Tax Expense

From the date of the corporate reorganization, our operations have been taxed at a combined U.S. federal and state effective tax rate of 35.7%. As a pass-through entity, our predecessor was subject only to the Texas margin tax at a statutory rate of 1.0% and was not subject to U.S. federal income tax. During the year ended December 31, 2014, we recognized $36.5 million of expense, an increase of $34.6 million, or 1821%, as compared to the $1.9 million we recognized during the year ended December 31, 2013. This increase was attributable to our status as a corporation subject to U.S. federal income tax as well as a net increase in operating income, the components of which are discussed above.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Year Ended December 31, 2013	Year Ended December 31, 2012	$ Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$ 97,839	$ 30,443	$ 67,396	221%
Natural gas and natural gas liquid sales	23,179	7,236	15,943	220%
Total revenues	$ 121,018	$ 37,679	$ 83,339	221%
Average realized prices(1):				
Oil sales, without realized derivatives (per Bbls)	$ 93.28	$ 85.60	$ 7.68	9%
Oil sales, with realized derivatives (per Bbls)	$ 87.91	$ 83.08	$ 4.83	6%
Natural gas and NGLs, without realized derivatives (per Mcf)	$ 4.95	$ 4.85	$ 0.10	2%
Natural gas and NGLs, with realized derivatives (per Mcf)	$ 4.95	$ 4.85	$ 0.10	2%
Average price per BOE, without realized derivatives	$ 66.17	$ 62.33	$ 3.84	6%
Average price per BOE, with realized derivatives	$ 63.09	$ 60.85	$ 2.24	4%
Production:				
Oil (MBbls)	1,049	356	693	195%
Natural gas and natural gas liquid (MMcf)	4,680	1,493	3,187	213%
Total (MBoe)(2)	1,829	604	1,225	203%
Average daily production volume:				
Oil (Bbls/d)	2,874	972	1,902	196%
Natural gas and natural gas liquids (Mcf/d)	12,823	4,079	8,744	214%
Total (Boe/d)	5,011	1,652	3,359	203%

(1) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

(2) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the years indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2013	2012
Average realized oil price ($/Bbl)	$ 93.28	$ 85.60
Average NYMEX ($/Bbl)	$ 98.61	$ 93.73
Differential to NYMEX	$ (5.33)	$ (8.13)
Average realized oil price to NYMEX percentage	95%	91%
Average realized natural gas price ($/Mcf)	$ 4.95	$ 0.10
Average NYMEX ($/Mcf)	$ 3.79	$ 2.91
Differential to NYMEX	$ 1.16	$ (2.81)
Average realized natural gas to NYMEX percentage	131%	3%

Oil revenues increased 221% to $97.8 million during year ended December 31, 2013 from $30.4 million during the year ended December 31, 2012. The increase is attributable to higher oil production volumes of 693 MBbls in conjunction with an increase in average oil prices of $7.68 per barrel. Of the overall changes in oil sales, increases in oil production volumes accounted for a positive change of $59.3 million while increases in oil prices accounted for a positive change of $8.1 million.

Natural gas and natural gas liquid revenues increased 220% to $23.2 million during the year ended December 31, 2013 from $7.2 million during the year ended December 31, 2012. The revenue increase is primarily a result of an increase in volumes sold of 3,187 MMcf. Natural gas revenue includes revenue from the sale of NGLs volumes.

Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Year ended December 31,			
	2013	2012	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$ 16,572	$ 4,646	$ 11,926	257%
Production and ad valorem taxes	7,081	2,412	4,669	194%
Depreciation, depletion and amortization	28,152	6,406	21,746	339%
General and administrative expenses	15,248	3,629	11,619	320%
Incentive unit compensation	1,233	—	1,233	100%
Accretion of asset retirement obligations	181	66	115	174%
Total operating expenses	$ 68,467	$ 17,159	$ 51,308	299%
Expense per Boe:				
Lease operating expenses	$ 9.06	$ 7.69	$ 1.37	18%
Production and ad valorem taxes	3.87	3.99	(0.12)	(3)%
Depreciation, depletion and amortization	15.39	10.60	4.79	45%
General and administrative expenses	8.34	6.00	2.34	39%
Incentive unit compensation	0.67	—	0.67	100%
Accretion of asset retirement obligations	0.10	0.11	(0.01)	(9)%
Total operating expenses per Boe	$ 37.43	$ 28.39	$ 9.04	32%

Lease Operating Expenses. Lease operating expenses increased 257% to $16.6 million during the year ended December 31, 2013 from $4.6 million during the year ended December 31, 2012. The increase is primarily due to the higher operated well count in the year ended December 31, 2013 as compared to the prior year period. On a per Boe basis, lease operating expenses increased to $9.06 per Boe from $7.69 per Boe. This increase was attributable to increases in costs for repair and maintenance for 170 new wells added, additional lease operators and increased water disposal activity.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased $4.7 million to $7.1 million during the year ended December 31, 2013 from $2.4 million during the year ended December 31, 2012 due to increased wellhead revenue resulting from higher production. Our increased drilling activity led to a higher number of wells brought on production during the year ended December 31, 2013 compared to the year ended December 31, 2012.

Depreciation, Depletion and Amortization. DD&A expense increased by $21.8 million to $28.2 million for the year ended December 31, 2013 from $6.4 million during the year ended December 31, 2012 due to an increase in capitalized costs and production volumes.

General and Administrative Expenses. General and administrative expenses increased $11.6 million to $15.2 million during the year ended December 31, 2013 from $3.6 million during the year ended December 31, 2012 primarily due to higher payroll and payroll-related costs as we added additional employees to manage our growing asset base, higher rig count and increased production.

Incentive Unit Compensation. Incentive unit compensation was incurred during the year ended December 31, 2013 due to the incentive unit compensation expense recognized in conjunction with the LLC interest issuance as described in *Note 10—Equity* in the notes to the consolidated and combined financial statements. No incentive unit compensation expenses were incurred during the year ended December 31, 2012.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Year ended December 31,			
	2013	2012	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Interest expense, net	$ (13,714)	$ (6,285)	$ (7,429)	118%
Prepayment premium paid on extinguishment of debt	—	(6,597)	6,597	(100)%
Income from equity investment	184	267	(83)	(31)%
Derivative loss	(9,800)	(2,190)	(7,610)	347%
Other income (expense)	159	(81)	240	(296)%
Total other expense, net	$ (23,171)	$ (14,886)	$ (8,285)	56%

Interest Expense. Interest expense increased $7.4 million to $13.7 million in the year ended December 31, 2013 from $6.3 million during the year ended December 31, 2012 primarily due to higher weighted-average outstanding borrowings under our credit facilities.

Prepayment Premium on Extinguishment of Debt. In 2012, we incurred a $6.6 million cash charge related to a call premium on our then outstanding debt facility. In 2013, there were no such prepayment charges related to debt extinguishment.

Derivative Loss. Loss on derivative instruments grew $7.6 million to $9.8 million during the year ended December 31, 2013 from $2.2 million during the year ended December 31, 2012 primarily as a result of the impact of changing commodity prices on increased hedging activities.

Gain on Sales of Oil and Natural Gas Properties

In August 2013, we sold our interest in seven non-operated wells and 190 net acres for total proceeds of $0.8 million and realized a $36,000 gain on the sale.

In April 2012, we sold 2,652 net unevaluated acres for $8.6 million and realized a $7.5 million gain on the sale.

Income Tax Expense

Although Parsley LLC's operations have not been subject to federal income tax in the past, our operations located in Texas are subject to an entity-level tax, the Texas margin tax, at a statutory rate of up to 1.0% of our Texas sourced operating income. During the year ended December 31, 2013, we recognized $1.9 million of expense associated with our Texas margin tax obligation, an increase of $1.3 million, or 217%, as compared to the $0.6 million we recognized during the year ended December 31, 2012. This increase was attributable to our net increase in operating income, the components of which are discussed above.

Capital Requirements and Sources of Liquidity

For the year ended December 31, 2014, our aggregate drilling and completion capital expenditures were $491.3 million. During the year ended December 31, 2013, our aggregate drilling and completion capital expenditures were $268.4 million. These capital expenditure totals exclude acquisitions.

Our 2015 capital budget for drilling and completion is approximately $225 million to $250 million. The amount and timing of 2015 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2015 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Based upon current oil and natural gas price expectations for the fiscal year 2015, we believe that our cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement will be sufficient to fund our operations through 2015. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. For example we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled in drilling locations not associated with proved reserves on our December 31, 2014 reserve report. The failure to achieve anticipated production and cash flows from operations from such wells could result in a reduction in future capital spending. Further, our capital expenditure budget for 2015 does not allocate any amounts for acquisitions of leasehold interests and proved properties. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot assure you that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
Net cash provided by operating activities	$ 184,983	$ 53,235	$ 5,025
Net cash used in investing activities	(1,247,677)	(425,611)	(89,539)
Net cash provided by financing activities	1,093,851	378,096	74,245

Cash Flow Provided by Operating Activities. Net cash provided by operating activities was approximately $185.0 million, $53.2 million, and $5.0 million for the years ended December 31, 2014, 2013, and 2012, respectively. The $131.8 million increase in operating cash flows was due to a $134.7 million increase in oil revenues for the year ended December 31, 2014 as compared to the year ended December 31, 2013, which is attributable to a 171% increase in crude oil production volumes, and a larger positive variance in working capital changes, which adjusts for the timing of receipts and payments of actual cash. The increase in cash flow was offset by increased capital spending resulting from an increase in drilling activity. Revenues, net of operating expenses, increased for the year ended December 31, 2013 as compared to the year ended December 31, 2012, and therefore our net cash provided by operating activities were consistent with the increase during that same period.

Cash Flow Used in Investing Activities. Net cash used in investing activities was approximately $1.2 billion, $425.6 million, and $89.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. The increased amount of cash used in investing activities in the year ended December 31, 2014 as compared to the year ended December 31, 2013 and the year ended December 31, 2013 as compared to the year ended December 31, 2012 was due primarily to the $553.9 million and 176.4 million, respective, increase in acquisition activity as discussed in *Note 6—Acquisition of Oil and Gas Properties*. The increases during 2014 over 2013 and 2013 over 2012 are also due to additional rigs operating, our horizontal drilling plan, and drilling higher working interest wells.

Cash Flow Provided by Financing Activities. Net cash provided by financing activities was approximately $1.1 billion, $378.1 million, and $74.2 million for the years ended December 31, 2014, 2013, and 2012, respectively. Net cash provided by financing activities increased during the year ended December 31, 2014 primarily due to the issuance of Class A Common Stock in conjunction with our IPO and corporate reorganization and the increase in long-term borrowings. For 2013, the cash provided by financing activities was primarily related to new borrowings under our credit facilities in addition to the $73.5 million equity investment that was closed in June 2013.

Capital Sources

Revolving Credit Agreement. The borrowing base will be redetermined by the lenders at least semi-annually on each April 1 and October 1, with the most recent redetermination on October 1, 2014. As of December 31, 2014, the borrowing base was $562.0 million, with a commitment level of $365.0 million. In February 2015, the borrowing base was decreased to $560.8, with a commitment level of $365.0 also resulting from restructuring of commodity price hedges. As of December 31, 2014, pro forma for the Private Placement, there were no outstanding borrowings under our Revolving Credit Agreement and $0.3 million in letters of credit outstanding as of December 31, 2014, resulting in availability of $364.7 million.

Our Revolving Credit Agreement is secured by liens on substantially all of our properties and guarantees from our subsidiaries. The Revolving Credit Agreement contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make or declare dividends;
- hedge future production or interest rates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Revolving Credit Agreement requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of consolidated current assets (including unused availability under our Revolving Credit Agreement) to consolidated current liabilities of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of EBITDAX to interest expense, of not less than 2.5 to 1.0 as of the last day of any fiscal quarter for the four fiscal quarters ending on such date.

The Revolving Credit Agreement also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

From time to time, the agents, arrangers, book runners and lenders under the Revolving Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to us and our affiliates in the ordinary course of business, for which they have received, or may in the future receive, customary fees and commissions for these transactions.

At December 31, 2014, we were in compliance with all required covenants.

7.500 % Senior Unsecured Notes due 2022. See *Note 9*—Debt to our consolidated and combined financial statements for the year ended December 31, 2014 included elsewhere in this annual report for a description of the Notes.

Derivative Activity. We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to continue our historical practice of entering into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil production over a two-to-three year period at a given point in time.

Working Capital

Our working capital totaled ($16.7) million, ($54.2) million, and ($10.0) at December 31, 2014, 2013 and 2012, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $50.6 million, $19.4 million, and $13.7 million at December 31, 2014, 2013, and 2012, respectively. The $31.2 million increase in cash is primarily attributable to the receipt of proceeds for the sale of Class A Common Stock in conjunction with our IPO and proceeds from additional borrowing on our Revolving Credit Agreement and Senior Unsecured Notes offset by acquisitions of oil and gas properties, as described in *Note 6—Acquisitions of Oil and Gas Properties* and debt repayments. Due to the amounts that we accrue related to our drilling program, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our credit agreement will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, derivative liabilities and other obligations.

We had the following contractual obligations at December 31, 2014:

	Payments Due by Period For the Year Ended December 31,						
	2015	2016	2017	2018	2019	Thereafter	Total
	(in thousands)						
Revolving Credit Agreement(1)	$ —	$ —	$ —	$ 120,000	$ —	$ —	$120,000
7.50% Senior Unsecured Notes due 2022 (1)(2)	—	—	—	—	—	550,000	550,000
Capital lease obligations (3)	650	688	705	26	—	—	2,069
Operating lease obligations (4)	3,029	3,025	4,481	4,866	4,977	21,005	41,383
Drilling commitments (5)	39,466	27,911	10,039	—	—	—	77,416
Asset retirement obligations(6)	1,069	1,094	646	973	43	12,380	16,205
Total	$ 44,214	$ 32,718	$ 15,871	$ 125,865	$ 5,020	$ 583,385	$807,073

(1) This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on Parsley's second lien credit facility because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) On February 5, 2014, Parsley LLC and Parsley Finance Corp. issued $400 million of the Notes. We repaid all outstanding borrowings under our second lien credit facility and $174.8 million of principal amounts outstanding under our Revolving Credit Agreement with the net proceeds from this offering. On April 14, 2014, Parsley LLC and Parsley Finance Corp. issued an additional $150 million of the Notes. We used approximately $145 million of the net proceeds to repay outstanding borrowings under our Revolving Credit Agreement.

(3) During 2014, we entered into capital lease agreements payable in connection with the lease of vehicles for operations and field personnel.

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

(5) We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital is incurred or rig services are provided.

(6) Amounts represent estimates of our predecessor's future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated and combined financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated and combined financial statements. See below for an expanded discussion of our significant accounting policies and estimates made by management.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized.

The provision for DD&A of oil and natural gas properties is calculated on a reservoir basis using the unit-of-production method. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and total proved reserves, respectively. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil. The calculation for the unit-of-production DD&A method takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values.

We capitalize interest on expenditures made in connection with long term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent we have incurred interest expense.

On the sale of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, amortization and impairment of unproved leasehold costs, and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete.

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as exploration costs in our Consolidated and Combined Statement of Operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

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

This report presents estimates of our proved reserves as of December 31, 2014, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2014 was based on an unweighted average twelve month WTI posted price of $85.99 per Bbl for oil and $35.27 per Bbl for NGLs, and a Henry Hub spot natural gas price of $4.28 per MMBtu for natural gas.

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

It should not be assumed that the Standardized Measure included in this report as of December 31, 2014 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2014 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 1A. Risk Factors" and "Item 2. Properties" for additional information regarding estimates of proved reserves.

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

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development costs on an annual basis.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and natural gas wells and our gathering systems, and to restore land at the end of oil and gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells and our gathering systems. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Equity Investments

Equity investments in which we exercise significant influence but do not control are accounted for using the equity method. Under the equity method, generally our share of investees' earnings or loss, after elimination of intra-company profit or loss, is recognized in the consolidated and combined statement of operations. We reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we would recognize an impairment provision. There was no impairment for our equity investments for the years ended December 31, 2014, 2013, or 2012.

Derivatives

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our oil production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter commodity derivative contracts with large financial institutions.

We apply the provisions of the "Derivatives and Hedging" topic of the ASC, which requires each derivative instrument to be recorded at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. We elected not to designate our current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings.

We enter into commodity derivative contracts for the purpose of economically hedging the price of our anticipated oil production even though we do not designate the derivatives as hedges for accounting purposes. We classify cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of our oil and natural gas operations, they are classified as cash flows from operating activities in the consolidated statements of cash flows. All commodity derivative contracts we have entered into are for the purpose of economically hedging our anticipated oil production.

As required by GAAP, we utilize the most observable inputs available for the valuation technique used. The financial assets and liabilities are classified in their entirety based on the lowest level of input that is of significance to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the financial assets and liabilities. Fair values of swaps are estimated using a combined income-based and market-based valuation methodology based upon forward commodity price curves obtained from independent pricing services. Settlement is determined by the average underlying price over a predetermined period of time. We use observable inputs in an option pricing valuation model to determine fair value such as: (i) current market and contractual prices for the underlying instruments; (ii) quoted forward prices for oil; (iii) interest rates, such as a LIBOR curve for a term similar to the commodity derivative contract; and (iv) appropriate volatilities.

Please read "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our commodity derivative contracts.

Income Taxes

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax laws and rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

We periodically assess whether it is more likely than not that we will generate sufficient taxable income to realize our deferred income tax assets, including net operating losses. In making this determination, we consider all available positive and negative evidence and make certain assumptions. We consider, among other things, our deferred tax liabilities, the overall business environment, our historical earnings and losses, current industry trends, and our outlook for future years. We believe it is more likely than not that certain net operating losses can be carried forward and utilized.

Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities, which are based on numerous judgments and assumptions inherent in the determination of future taxable income, at the end of each period as well as the effects of tax rate changes and tax credits. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Material changes to our tax accruals may occur in the future based on audits, changes in legislation or resolution of pending matters.

Off-Balance Sheet Arrangements

As of December 31, 2014, we had no material off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGLs production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGLs production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

We do not require collateral from our counterparties for entering into derivative instruments, so in order to mitigate the credit risk associated with such derivative instruments, we enter into an International Swap Dealers Association Master Agreement (“ISDA Agreement”) with each of our counterparties. The ISDA Agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each derivative transaction between the counterparty and us separately, the ISDA Agreement enables the counterparty and us to aggregate all trades under such agreement and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under a single trade can trigger rights to terminate all trades with such counterparty that are subject to the ISDA Agreement; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

As of December 31, 2014, the fair market value of our oil derivative contracts was a net asset of $88.9 million. Based on our open oil derivative positions at December 31, 2014, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $14.5 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $13.7 million. As of December 31, 2014, the fair market value of our natural gas derivative contracts was a net asset of $2.3 million. Based upon our open commodity derivative positions at December 31, 2014, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $0.2 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivate asset by approximately $0.2 million. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs.”

Counterparty Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as it deems appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. We plan to continue to evaluate the credit standings of our counterparties in a similar manner. A portion of our derivative contracts currently in place are with lenders under our Revolving Credit Agreement, who have investment grade ratings.

Interest Rate Risk

Our market risk exposure related to changes in interest rates relates primarily to debt obligations. We are exposed to changes in interest rates as a result of our Revolving Credit Agreement, and the terms of our Revolving Credit Agreement require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments.

At December 31, 2014, we had $120 million of variable-rate debt outstanding, with an interest rate of LIBOR plus 1.50%, or 1.67%. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $1.2 million per year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2014. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014 at the reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the fourth quarter of 2014 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

The information required in response to this item will be set forth in our definitive proxy statement for the 2015 annual meeting of stockholders and is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive proxy statement for the 2015 Annual Meeting of Stockholders which is incorporated herein by reference. Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the Commission initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, officers and 10% holders are required by Commission regulations to send us copies of all of the Section 16(a) reports they file.

Based solely on a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, other than as described below, during the fiscal year ended December 31, 2014, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act, with the following exceptions. Mssrs. Alameddine, Carter, Newcomer and Smith each had a delinquent Form 4 filing on June 2, 2014 for a transaction occurring on May 29, 2014.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2015 annual meeting of stockholders and is incorporated herein by reference.

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

The following table sets forth information about our common stock that may be issued under equity compensation plans as of December 31, 2014:

	(a)	(b)	(c)
	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (1)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (2)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))(3)
Equity compensation plans approved by security holders(a)	—	$ —	—
Equity compensation plans not approved by security holders	23,649	$ —	11,957,579
Total	23,649	$ —	11,957,579

(1) This column reflects all restricted stock units granted under the Parsley Energy, Inc. 2014 Long Term Incentive Plan (the "LTIP") outstanding and unvested as of December 31, 2014. No stock options or warrants have been granted under the LTIP.

(2) No stock options have been granted under the LTIP and restricted stock units reflected in column (a) are not reflected in this column as they do not have an exercise price.

(3) This column reflects the total number of shares remaining available for issuance under the LTIP.

Our only equity compensation plan is the LTIP. The LTIP was approved by our stockholders prior to our initial public offering but has not been approved by our public stockholders. Please read Note 10 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of our equity compensation plans. In addition, a detailed description of the terms of the LTIP is available in our registration statement on Form S-1, last filed on May 22, 2014 under the heading "Executive Compensation—2014 Long Term Incentive Plan."

Additional information required in response to this item will be set forth in our definitive proxy statement for the 2015 annual meeting of stockholders and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2015 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2015 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1. The following documents are filed as part of this report or incorporated by reference:

   a. Financial Statements:

      Our consolidated and combined financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated and Combined Financial Statements" on page F-1 of this annual report.

   b. Financial Statement Schedules:

      All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements and related notes

2. Exhibits

   The exhibits required to be filed by Item 15 are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K.

EXHIBIT INDEX

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of May 29, 2014, by and between Parsley Energy Employee Holdings, LLC and Parsley Energy, Inc. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
2.2	Purchase and Sale Agreement, dated as of June 4, 2014, by and among OGX Production, LP, OGX Operating, LLC and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
2.3	Purchase and Sale Agreement, dated as of March 27, 2014, by and between Pacer Energy, Ltd and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 14, 2014).
2.4	First Amendment to Purchase and Sale Agreement and Waiver of Conditions Precedent, dated as of May 1, 2014, by and between Pacer Energy, Ltd. and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.4 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 14, 2014).
2.5	Purchase and Sale Agreement, dated as of August 19, 2014, by and between Cimarex Energy Co. and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 25, 2014).
3.1	Amended and Restated Certificate of Incorporation of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
3.2	Amended and Restated Bylaws of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
4.1	Indenture, dated as of February 5, 2014, by and among Parsley Energy, LLC, Parsley Finance Corp., each of the guarantors party thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
4.2	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
4.3	Amended and Restated Registration Rights Agreement, dated as of May 29, 2014, by and among Parsley Energy, LLC, Parsley Energy, Inc. and each of the parties listed as Owners on the signature pages thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.1	Amended and Restated Credit Agreement, dated as of October 21, 2013, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Amendment No. 1 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 5, 2014).
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of December 20, 2013, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated as of February 5, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).

Exhibit No.	Description
10.4	Fifth Amendment to Amended and Restated Credit Agreement, dated as of May 9, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.19 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.5*	Sixth Amendment to Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto.
10.6	Seventh Amendment to Amended and Restated Credit Agreement, dated as of November 10, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 14, 2014).
10.7	Amended and Restated Credit Agreement, dated October 21, 2013, by and among Parsley Energy, L.P., as borrower, Chambers Energy Management, LP, as agent and the several lenders party thereto (incorporated by reference to Exhibit 10.2 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.8†	Employment Agreement, dated as of January 23, 2014, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.9†	Employment Agreement, dated as of January 24, 2014, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.10†	Amended and Restated Employment Agreement, dated as of December 8, 2014, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 9, 2014).
10.11†	Employment Agreement, dated as of February 13, 2014, by and between Parsley Energy Operations, LLC and Matthew Gallagher (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.12†*	Employment Agreement, dated as of December 8, 2014, by and between Parsley Energy Operations, LLC and Thomas Layman.
10.13	Amended and Restated Limited Liability Company Agreement of Parsley Energy Employee Holdings, LLC (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.14	Master Reorganization Agreement, dated as of May 2, 2014, by and among Parsley Energy, Inc., NGP X US Holdings, L.P., Parsley Energy, LLC, the persons identified on the signature page thereto as Existing Members and Parsley Energy Employee Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 28, 2014).
10.15	First Amended and Restated Limited Liability Company Agreement of Parsley Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.16	Tax Receivable Agreement, dated as of May 29, 2014, by and among Parsley Energy, Inc., certain members of Parsley Energy, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.17†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Bryan Sheffield (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).

Exhibit No.	Description
10.18†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Ryan Dalton (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.19†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Michael Hinson (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.20†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Matt Gallagher (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.21†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Paul Treadwell (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.22†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Thomas Layman (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.23†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Colin Roberts (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.24†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Chris Carter (incorporated by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.25†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and David Smith (incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.26†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and A.R. Alameddine (incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.27†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Randy Newcomer (incorporated by reference to Exhibit 10.13 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.28†	Indemnification Agreement, dated as of July 23, 2014, by and between Parsley Energy, Inc. and Hemang Desai (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on July 24, 2014).
10.29†	Indemnification Agreement, dated as of August 19, 2014, by and between Parsley Energy, Inc. and William Browning (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 25, 2014).
10.30†*	Amended and Restated Parsley Energy, Inc. 2014 Long Term Incentive Plan.
10.31†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.32†	Form of Notice of Grant of Restricted Stock (Time-Based) (incorporated by reference to Exhibit 10.17 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.33†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.34†*	Form of Restricted Stock Unit Agreement.

Exhibit No.	Description
10.35†*	Form of Notice of Grant of Restricted Stock Units (Time-Based).
10.36†*	Form of Notice of Grant of Restricted Stock Units (Performance-Based).
10.37	Common Stock Subscription Agreement, dated as of February 5, 2015, by and among Parsley Energy, Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 11, 2015).
10.38	Registration Rights Agreement, dated as of February 11, 2015, by and among Parsley Energy, Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 11, 2015).
21.1*	List of Subsidiaries of Parsley Energy, Inc.
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. Reserve Report.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

† Management contract or compensatory plan or agreement

* Filed herewith. Schedules and similar attachments to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant will furnish a supplemental copy of any omitted schedule or similar attachment to the Commission upon request.

** Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this Annual Report on Form 10-K and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

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.

March 11, 2015	By: /s/ Bryan Sheffield Bryan Sheffield Chairman, President and Chief Executive Officer

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

March 11, 2015	By: /s/ Bryan Sheffield Bryan Sheffield Chairman, President and Chief Executive Officer (Principal Executive Officer)
March 11, 2015	By: /s/ Ryan Dalton Ryan Dalton Vice President—Chief Financial Officer (Principal Accounting and Financial Officer)
March 11, 2015	By: /s/ A.R. Alameddine A.R. Alameddine Director
March 11, 2015	By: /s/ William Browning William Browning Director
March 11, 2015	By: /s/ Chris Carter Chris Carter Director
March 11, 2015	By: /s/ Hemang Desai Hemang Desai Director
March 11, 2015	By: /s/ Randolph Newcomer, Jr. Randolph Newcomer, Jr. Director
March 11, 2015	By: /s/ David H. Smith David H. Smith Director

Index to Consolidated and Combined Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Parsley Energy, Inc.:

We have audited the accompanying consolidated and combined balance sheets of Parsley Energy, Inc. and subsidiaries (the Company) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

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

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Parsley Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

(signed) KPMG LLP

Dallas, Texas
March 11, 2015

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED AND COMBINED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 50,550	$ 19,393
Accounts receivable:		
Joint interest owners and other	37,620	90,490
Oil and gas	22,700	15,202
Related parties	4,065	1,041
Short-term derivative instruments	80,911	6,999
Materials and supplies	3,767	3,078
Other current assets	4,548	1,123
Total current assets	204,161	137,326
PROPERTY, PLANT AND EQUIPMENT, AT COST		
Oil and natural gas properties, successful efforts method	1,872,616	614,315
Accumulated depreciation, depletion and amortization	(128,044)	(34,957)
Total oil and natural gas properties, net	1,744,572	579,358
Other property, plant and equipment, net	16,290	7,525
Total property, plant and equipment, net	1,760,862	586,883
NONCURRENT ASSETS		
Long-term derivative instruments	70,805	13,850
Equity investment	2,121	1,774
Deferred loan costs, net	12,943	2,723
Other noncurrent assets	187	—
Total noncurrent assets	86,056	18,347
TOTAL ASSETS	$ 2,051,079	$ 742,556
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 139,922	$ 158,385
Revenue and severance taxes payable	38,366	28,419
Current portion of long-term debt	650	227
Short-term derivative instruments	29,326	4,435
Current deferred tax liability	12,601	—
Amounts due related parties	—	31
Total current liabilities	220,865	191,497
NONCURRENT LIABILITIES		
Long-term debt	676,845	429,970
Asset retirement obligations	16,207	8,277
Deferred tax liability	62,334	2,572
Payable pursuant to tax receivable agreement	50,689	—
Long-term derivative instruments	31,275	2,208
Other noncurrent liabilities	375	—
Total noncurrent liabilities	837,725	443,027
COMMITMENTS AND CONTINGENCIES		
MEMBERS' EQUITY	—	30,874
MEZZANINE EQUITY	—	77,158
STOCKHOLDERS' EQUITY		
Preferred Stock, $.01 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common Stock		
Class A, $.01 par value, 600,000,000 shares authorized, 93,937,947 issued and 93,901,208 outstanding at December 31, 2014 and 1,000 issued and outstanding at December 31, 2013	932	—
Class B, $.01 par value, 125,000,000 shares authorized, 32,145,296 issued and outstanding at December 31, 2014 and none issued and outstanding at December 31, 2013	321	—
Additional paid in capital	644,636	—
Retained earnings	61,352	—
Treasury Stock, at cost, 36,739 shares and none at December 31, 2014 and December 31, 2013	—	—
Total stockholders' equity	707,241	—
Noncontrolling interest	285,248	—
Total equity	992,489	108,032
TOTAL LIABILITIES AND EQUITY	$ 2,051,079	$ 742,556

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS

	Year ended December 31, 2014	2013	2012
	(in thousands, except per share data)		
REVENUES			
Oil sales	$ 232,554	$ 97,839	$ 30,443
Natural gas and natural gas liquids sales	69,203	23,179	7,236
Total revenues	301,757	121,018	37,679
OPERATING EXPENSES			
Lease operating expenses	38,071	16,572	4,646
Production and ad valorem taxes	18,941	7,081	2,412
Depreciation, depletion and amortization	94,297	28,152	6,406
General and administrative expenses	34,997	15,248	3,629
Exploration costs	3,136	—	—
Acquisition costs	2,527	—	—
Incentive unit compensation	51,088	1,233	—
Stock based compensation	2,209	—	—
Accretion of asset retirement obligations	512	181	66
Total operating expenses	245,778	68,467	17,159
(Loss) gain on sale of property	(2,097)	36	7,819
OPERATING INCOME	53,882	52,587	28,339
OTHER INCOME (EXPENSE)			
Interest expense, net	(38,607)	(13,714)	(6,285)
Rig termination costs	(765)	—	—
Prepayment premium on extinguishment of debt	(5,107)	—	(6,597)
Income from equity investment	348	184	267
Derivative income (loss)	83,858	(9,800)	(2,190)
Other income (expense)	(419)	159	(81)
Total other income (expense), net	39,308	(23,171)	(14,886)
INCOME BEFORE INCOME TAXES	93,190	29,416	13,453
INCOME TAX EXPENSE	(36,468)	(1,906)	(554)
NET INCOME	56,722	27,510	12,899
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(33,293)	—	—
NET INCOME ATTRIBUTABLE TO PARSLEY ENERGY INC. STOCKHOLDERS	$ 23,429	$ 27,510	$ 12,899
Net income per common share:			
Basic	$ 0.42		
Diluted	$ 0.42		
Weighted average common shares outstanding:			
Basic	55,136		
Diluted	55,239		

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED AND COMBINED STATEMENT OF CHANGES IN EQUITY

			Issued Shares						Shares				
	Members' Equity	Mezzanine equity	Class A common stock	Class B common Stock	Class A common stock	Class B common Stock	Additional paid in capital	Retained Earnings	Treasury stock	Treasury stock	Total Stockholders' equity	Noncontrolling interest	Total Equity
							(In thousands)						
Balance at 12/31/2011	$ 9,053	$ —	—	—	$ —	$ —	$ —	$ —	—	$ —	$ —	$ —	$ 9,053
Distributions	(15,935)	—	—	—	—	—	—	—	—	—	—	—	(15,935)
Net income	12,899	—	—	—	—	—	—	—	—	—	—	—	12,899
Balance at 12/31/2012	6,017	—	—	—	—	—	—	—	—	—	—	—	6,017
LLC interest issuance	—	77,158											77,158
Preferred return on redeemable LLC interests	(3,886)	—	—	—	—	—	—	—	—	—	—	—	(3,886)
Deemed contribution - incentive unit compensation	1,233	—	—	—	—	—	—	—	—	—	—	—	1,233
Net income	27,510	—	—	—	—	—	—	—	—	—	—	—	27,510
Balance at 12/31/2013	30,874	77,158	—	—	—	—	—	—	—	—	—	—	108,032
Preferred return on redeemable LLC interests	(1,723)	1,723	—	—	—	—	—	—	—	—	—	—	—
Net loss prior to corporate reorganization	(37,923)	—	—	—	—	—	—	—	—	—	—	—	(37,923)
Balance prior to Corporate Reorganization and Offering	(8,772)	78,881	—	—	—	—	—	—	—	—	—	—	70,109
Reorganization Transactions:													
Payment of Preferred Return	—	(6,726)	—	—	—	—	—	—	—	—	—	—	(6,726)
Conversion of PE Units for Class A Common Stock and Class B Common Stock	(42,316)	(72,155)	43,204	32,145	432	321	113,718	—	—	—	114,471	—	—
Net deferred tax liability due to corporate reorganization	—	—	—	—	—	—	(95,530)	—	—	—	(95,530)	—	(95,530)
Deemed contribution - incentive unit compensation	51,088	—	—	—	—	—	—	—	—	—	—	—	51,088
Offering Transactions:													
Issuance of Class A Common Stock, net of underwriters discount and expenses	—	—	49,963	—	500	—	867,250	—	—	—	867,750	—	867,750
Initial allocation of noncontrolling interest of Parsley LLC effective on the date of the Offering	—	—	—	—	—	—	(251,955)	—	—	—	(251,955)	251,955	—
Tax benefit from tax receivable agreement	—	—	—	—	—	—	59,633	—	—	—	59,633	—	59,633
Liability due to tax receivable agreement	—	—	—	—	—	—	(50,689)	—	—	—	(50,689)	—	(50,689)

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED AND COMBINED STATEMENT OF CHANGES IN EQUITY
(continued)

	Members' Equity	Mezzanine equity	Issued Shares: Class A common stock	Issued Shares: Class B common Stock	Class A common stock	Class B common Stock	Additional paid in capital	Retained Earnings	Shares: Treasury stock	Treasury stock	Total Stockholders' equity	Noncontrolling interest	Total Equity
	(In thousands)												
Issuance of restricted stock and restricted stock units	—	—	770	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	(41)	—	37	—	(41)	—	(41)
Stock based compensation	—	—	—	—	—	—	2,250	—	—	—	2,250	—	2,250
Consolidated net income subsequent to the Corporate Reorganization and the Offering	—	—	—	—	—	—	—	61,352	—	—	61,352	33,293	94,645
Balance at 12/31/2014	$ —	$ —	93,937	32,145	$ 932	$ 321	$ 644,636	$ 61,352	37	$ —	$ 707,241	$ 285,248	$992,489

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2014	2013	2012
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 56,722	$ 27,510	$ 12,899
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	94,297	28,152	6,406
Unproved leasehold impairment	742	—	—
Accretion of asset retirement obligations	512	181	66
Loss (gain) on sale of oil and natural gas properties	2,097	(36)	(7,819)
Amortization of debt issue costs	2,327	1,225	853
Amortization of bond premium	(574)	—	—
Interest not paid in cash	234	2,597	1,845
Income from equity investment	(348)	(184)	(267)
Provision for deferred income taxes	36,468	1,906	548
Deemed contribution - incentive unit compensation	51,088	1,233	—
Stock based compensation	2,209	—	—
Derivative (income) loss	(83,858)	9,800	2,190
Net cash received (paid) for derivative settlements	3,311	(198)	179
Net cash received (paid) for option premiums	193	(16,342)	(9,318)
Net cash paid to margin account	(320)	(462)	(35)
Changes in operating assets and liabilities, net of acquisitions:			—
Accounts receivable	45,372	(77,086)	(18,040)
Other current assets	241	(348)	212
Materials and supplies	(689)	(867)	(1,866)
Other noncurrent assets	(187)	—	—
Accounts payable and accrued expenses	(32,121)	57,532	14,726
Revenue and severance taxes payable	9,947	19,243	3,653
Amounts due to/from related parties	(3,055)	(621)	(1,207)
Other noncurrent liabilities	375	—	—
Net cash provided by operating activities	184,983	53,235	5,025
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development of oil and natural gas properties	(477,681)	(209,859)	(66,352)
Acquisitions of oil and natural gas properties	(762,244)	(208,381)	(31,954)
Additions to other property and equipment	(7,924)	(8,121)	(328)
Proceeds from sales of oil and natural gas properties	172	750	9,295
Investment in equity investment	—	—	(200)
Net cash used in investing activities	(1,247,677)	(425,611)	(89,539)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under long-term debt	946,140	561,218	128,298
Payments on long-term debt	(700,766)	(254,100)	(37,012)
Debt issue costs	(12,547)	(2,294)	(871)
Proceeds from issuance of common stock, net	867,750	—	—
Payment of Preferred Return	(6,726)	—	—
Proceeds from issuance of LLC interests	—	73,540	—
Equity issue costs	—	(268)	(235)
Distributions	—	—	(15,935)
Net cash provided by financing activities	1,093,851	378,096	74,245
Net increase in cash and cash equivalents	31,157	5,720	(10,269)
Cash and cash equivalents at beginning of period	19,393	13,673	23,942
Cash and cash equivalents at end of period	$ 50,550	$ 19,393	$ 13,673
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 26,235	$ 13,536	$ 4,661
Cash paid for income taxes	$ —	$ —	$ 6
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:			
Asset retirement obligations incurred, including changes in estimate	$ 7,498	$ 6,238	$ 1,040
Additions to oil and natural gas properties - change in capital accruals	$ 13,658	$ 58,540	$ 5,593
Additions to other property and equipment funded by capital lease borrowings	$ 2,263	$ —	$ —

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

NOTE 1. ORGANIZATION AND NATURE OF OPERATIONS

Parsley Energy, Inc. (together with its subsidiaries, the "Company") was formed on December 11, 2013, pursuant to the laws of the State of Delaware, as a wholly-owned subsidiary of Parsley Energy, LLC ("Parsley LLC"), a Delaware limited liability company formed on June 11, 2013 and is engaged in the acquisition, development, production, exploration, and sale of crude oil and natural gas properties located primarily in the Permian Basin, which is located in West Texas and Southeastern New Mexico. Concurrent with the formation of Parsley Energy, LLC, all of the interest holders of Parsley Energy, L.P. ("Parsley LP"), Parsley Energy Management, LLC ("PEM") and Parsley Energy Operations, LLC ("PEO") exchanged their interest in each entity in return for interest in Parsley Energy, LLC (the "Exchange"). Prior to the formation of Parsley Energy, LLC, 67.8% of Parsley LP, 100% of PEM and 100% of PEO were held by Mr. Bryan Sheffield, Parsley Energy, LLC's President and Chief Executive Officer ("Sheffield"). Subsequent to Parsley Energy, LLC's formation, Sheffield controlled 53.7% of Parsley Energy, LLC. As such, as all power and authority to control the core functions of Parsley LP, PEM and PEO were, and continue to be, controlled by Sheffield, the Exchange has been treated as a reorganization of entities under common control and the results of Parsley LP, PEM and PEO have been consolidated and combined for all periods.

Parsley LP was formed on February 29, 2008, as a Texas limited partnership and is primarily engaged in the acquisition, development, production, exploration, and sale of crude oil and natural gas properties located in the Permian Basin in West Texas. On September 9, 2011, Parsley LP formed, and held all of the interest in, Spraberry Energy, LLC ("Spraberry"), a Texas limited liability company. On November 20, 2012, Spraberry merged with and into Parsley LP, thereby terminating Spraberry's corporate existence.

PEM was formed on February 19, 2008, as a Texas limited liability company and was formed to be the general partner of Parsley LP.

PEO was formed on February 19, 2008, as a Texas limited liability company and is primarily engaged in the operation of crude oil and natural gas properties located in the Permian Basin in West Texas.

Parsley LP also owns a noncontrolling 42.5% investment in Spraberry Production Services LLC ("SPS"). SPS was formed on August 27, 2010, as a Texas limited liability company and is primarily engaged in the oilfield services business servicing properties located in the Permian Basin in West Texas.

Initial Public Offering

On May 29, 2014, the Company completed its initial public offering (the "Offering") of 57.5 million shares of the Company's Class A common stock, par value $0.01 per share ("Class A Common Stock") at a price of $18.50 per share. Approximately 7.5 million of the shares were sold by selling stockholders and the Company did not receive any proceeds from the sale of those shares. The remaining approximately 50 million shares of the Company's Class A Common Stock that were sold resulted in gross proceeds of approximately $924.3 million to the Company and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $867.8 million. The material terms of the Offering are described in the Company's final prospectus, dated May 22, 2014 and filed with the Securities and Exchange Commission ("SEC") pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on May 27, 2014.

A portion of the proceeds from the Offering were used to repay all outstanding borrowings under the Revolving Credit Agreement (as defined herein), to make a cash payment in settlement of the Preferred Return (as defined herein), to fund the OGX Acquisition (as defined herein), and to pay fees and expenses related to the Offering. The remaining proceeds will be used to fund a portion of the Company's exploration and development program and for general corporate purposes.

Corporate Reorganization

On May 29, 2014, in connection with the Offering, Parsley LLC underwent a corporate reorganization ("Corporate Reorganization") whereby (a) all of the membership interests (including outstanding incentive units) in Parsley LLC held by its then existing owners (the "Existing Owners") were converted into a single class of units in Parsley LLC ("PE Units"), (b) certain of the Existing Owners contributed all of their PE Units to the Company in exchange for an equal number of shares of the Company's Class A Common Stock, (c) certain of the Existing Owners contributed only a portion of their PE Units to the Company in exchange for an equal number of shares of the Company's Class A Common Stock and continue to own a portion of the PE Units and (d) Parsley Energy Employee Holdings, LLC ("PEEH"), an entity owned by certain of Parsley LLC's officers and employees that was formed to hold a portion of the incentive units in Parsley LLC, was merged with and into the Company, with the Company surviving the merger and the members of PEEH receiving shares of the Company's Class A Common Stock. As a result of the above transactions, the Company issued a total of 43.2 million shares of its Class A Common Stock.

Upon completion of the Offering, the Company issued and contributed 32.1 million shares of its Class B common stock, par value $0.01 per share ("Class B Common Stock") and all of the net proceeds of the Offering to Parsley LLC in exchange for 93.2 million PE Units. Parsley LLC distributed to each of the Existing Owners that continued to own PE Units following the Corporate Reorganization and the Offering (collectively, the "PE Unit Holders"), one share of Class B Common Stock for each PE Unit such PE Unit Holder held. After giving effect to these transactions the Company owns an approximate 74.3% interest in Parsley LLC and Parsley LLC became a majority-owned subsidiary of the Company. The PE Unit Holders own an approximate 25.7% interest in Parsley LLC.

NOTE 2. BASIS OF PRESENTATION

These consolidated and combined financial statements include the accounts of Parsley Energy, Inc. and its majority-owned subsidiary, Parsley LLC, and its wholly-owned subsidiaries: (i) Parsley LP, (ii) PEM, (iii) PEO, and its wholly-owned subsidiary, Parsley Energy Aviation, LLC, and (iv) Parsley Finance Corp. Parsley LP owns a 42.5% noncontrolling interest in SPS. The Company accounts for its investment in SPS using the equity method of accounting. All significant intercompany and intra-company balances and transactions have been eliminated.

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Corporate Reorganization has been accounted for as transactions between entities under common control thus the accompanying consolidated and combined financial statements and related notes of the Company have been retrospectively re-cast to include the historical results of the entities involved at historical carrying values and their operations as if they were consolidated and combined for all periods presented.

NOTE 3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

These consolidated and combined financial statements and related notes are presented in accordance with GAAP. Preparation in accordance with GAAP requires us to (1) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and by the SEC and (2) make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our management believes the major estimates and assumptions impacting our consolidated and combined financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depletion, depreciation and amortization and impairment of capitalized costs of oil and natural gas properties;
- operating costs accrued and volumes and prices for revenues accrued;
- estimates of asset retirement obligations;
- estimates of the fair value of oil and natural gas properties we own, particularly properties that we have not yet explored, or fully explored, by drilling and completing wells;
- estimates of the fair value assets acquired and liabilities assumed in business combinations;
- evaluations of impairment of proved and unproved properties are subject to number uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks;
- impairment other assets;
- depreciation of property and equipment;
- valuation of commodity derivative instruments; and
- estimates of the fair value of stock based compensation.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Cash and Cash Equivalents

Cash and cash equivalents include demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and crude oil, NGLs, and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date.

Amounts due from joint interest owners or purchasers are stated net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2014 or December 31, 2013.

For the years ended December 31, 2014, 2013 and 2012, each of the following purchasers accounted for more than 10% of our revenue:

	Year Ended December 31,		
	2014	2013	2012
Atlas Pipeline Mid-Continent WestTex, LLC	20%	16%	14%
Plains Marketing, L.P	15%	22%	16%
BML, Inc.	14%	2%	—%
Permian Transport & Trading	11%	25%	20%
Enterprise Crude Oil, LLC	10%	20%	26%
Shell Trading (US) Company	4%	7%	17%

The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Material and Supplies

Materials and supplies are stated at the lower of cost or market and consists of oil and gas drilling or repair items such as tubing, casing and pumping units. These items are primarily acquired for use in future drilling or repair operations and are carried at lower of cost or market. "Market", in the context of valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. As of December 31, 2014, the Company estimated that all of its tubular goods and equipment will be utilized within one year.

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. At December 31, 2014, 2013 and 2012, the Company had excluded $624.2 million, $68.2 million and $14.0 million, respectively, of capitalized costs from depletion. Depreciation and depletion expense on capitalized oil and gas property was $92.8 million, $27.1 million and $6.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Company had no exploratory wells in progress at December 31, 2014, 2013 or 2012.

The Company capitalizes interest on expenditures made in connection with long term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the company has incurred interest expense. During the years ended December 31, 2014, 2013, and 2012, the Company capitalized interest of $2.7 million, $3.4 million and $1.0 million, respectively.

On the sale of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by reservoir using the units-of-production method. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Asset Retirement Obligations

For the Company, asset retirement obligations represent the future abandonment costs of tangible assets, namely the plugging and abandonment of wells and land remediation. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

Inherent to the present-value calculation are numerous estimates, assumptions, and judgments, including, but not limited to: the ultimate settlement amounts, inflation factors, credit-adjusted risk-free rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions affect the present value of the abandonment liability, the Company makes corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. These revisions result in prospective changes to DD&A expense and accretion of the discounted abandonment liability.

The following table summarizes the changes in the Company's asset retirement obligation for the periods indicated:

	December 31,	
	2014	2013
	(in thousands)	
Asset retirement obligations, January 1	$ 8,277	$ 1,858
Additional liabilities incurred	6,604	3,915
Liabilities assumed	—	2,420
Disposition of wells	(80)	(45)
Accretion expense	512	181
Liabilities settled upon plugging and abandoning wells	(7)	(3)
Revision of estimates	901	(49)
Asset retirement obligations, December 31	$ 16,207	$ 8,277

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Impairment of Long-Lived Assets

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties by reservoir. Whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, an impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. The Company recognized no impairment expense on proved oil and natural gas properties during the years ended December 31, 2014, 2013, or 2012.

Exploration costs

Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, impairment and amortization of unproved leasehold costs, and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete.

The Company recorded $2.4 million of geological and geophysical costs during the year ended December 31, 2014 and no such expenses for the years ended December 31, 2013 and 2012.

Unproved oil and natural gas properties are each periodically assessed for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. The Company recorded $0.7 million of impairment charges related to unproved oil and natural gas properties during the year ended December 31, 2014 and no impairment charges for the years ended December 31, 2013, or 2012. All of these expenses are included in “exploration costs” on the Consolidated and Combined Statement of Operations.

Other Property and Equipment, net

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the consolidated and combined balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years. Construction in process includes costs related to the construction of the new office space. All construction in process is expected to be completed during 2015 and will be depreciated using the straight-line-method once construction is complete and the assets are placed in use. Depreciation expense on other property and equipment was $1.5 million, $1.1 million and $0.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

	December 31,	
	2014	2013
	(in thousands)	
Buildings	$ 2,660	$ 2,117
Computers, software, and equipment	4,011	325
Airplane	4,533	3,729
Vehicles	2,611	102
Furniture and fixtures	1,734	676
Land	1,189	1,299
Leasehold improvements	439	545
Machinery and equipment	188	97
Construction in process	1,812	—
Property and equipment	19,177	8,890
Accumulated depreciation	(2,887)	(1,365)
Property and equipment, net	$ 16,290	$ 7,525

Equity Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, generally the Company's share of investees' earnings or loss, after elimination of intra-company profit or loss, is recognized in the consolidated and combined statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company would recognize an impairment provision. There was no impairment for the Company's equity investments for the years ended December 31, 2014, 2013, or 2012.

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of crude options and collars.

The Company reports the fair value of derivatives on the Consolidated and Combined Balance Sheets in derivative instrument assets and derivative instrument liabilities as either current or noncurrent. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The Company reports these on a gross basis by contract.

The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the Consolidated and Combined Statements of Operations in the period of change. Gains and losses from derivatives are included in cash flows from operating activities.

Fair Value of Financial Instruments

Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants at the reporting date. The Company's assets and liabilities that are measured at fair value at each reporting date are classified according to a hierarchy that prioritizes inputs and assumptions underlying the valuation techniques. This fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs, and consists of three broad levels:

- Level 1 measurements are obtained using unadjusted quoted prices in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities as of the reporting date.
- Level 2 measurements use as inputs market prices which are either directly or indirectly observable as of the reporting date for similar commodity derivative contracts. The Company valued its level 2 assets and liabilities using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, time value, volatility factors, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.
- Level 3 measurements are based on process or valuation models that use inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little of no market activity). These inputs generally reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Deferred Loan Costs

Deferred loan costs are stated at cost, net of amortization, and are amortized to interest expense using the effective interest method over the life of the loan.

Revenue Recognition

Revenues from the sale of crude oil, NGLs, and natural gas are recognized when the production is sold, net of any royalty interest. Because final settlement of the Company's hydrocarbon sales can take up to two months, the expected sales volumes and prices for those properties are estimated and accrued using information available at the time the revenue is recorded. Natural gas revenues are recorded using the entitlement method of accounting whereby revenue is recognized based on the Company's proportionate share of natural gas production. At December 31, 2013 and 2012, the Company did not have any natural gas imbalances. Transportation expenses are included as a reduction of natural gas revenue and are not material.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allow eligible employees to contribute a portion of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contribution of up to a certain percentage of an employee's contributions. For the year ended December 31, 2014, 2013, and 2012, the Company made contributions to the plan of $0.8 million, $0.2 million, and $0.1 million, respectively

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. The Company believes it is more likely than not that certain net operating losses can be carried forward and utilized.

Parsley LLC, the Company's accounting predecessor, is a limited liability company that is not subject to U.S. federal income tax.

Earnings per Share

The Company uses the "if-converted" method to determine the potential dilutive effect of its Class B Common Stock, and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock and restricted stock units.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Segment Reporting

The Company operates in only one industry segment: the oil and natural gas exploration and production industry in the United States. All revenues are derived from customers located in the United States.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current presentation

Recent Accounting Pronouncements

In June 2014, the FASB issued ASU No. 2014-12, *Compensation - Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved after the Requisite Service Period.* This ASU provides more explicit guidance for treating share-based payment awards that require a specific performance target that affects vesting and that could be achieved after the requisite service period as a performance condition. The new guidance is effective for annual and interim reporting periods beginning after December 15, 2015. The Company does not expect the adoption of this guidance to have a material impact on the consolidated and combined financial statements.

On May 28, 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU will replace most existing revenue recognition guidance in GAAP when it becomes effective. The new standard will be effective for the Company on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its consolidated and combined financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

NOTE 4. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Instruments and Concentration of Risk

Objective and Strategy

The Company uses derivative financial instruments to manage its exposure to cash-flow variability from commodity-price risk inherent in its exploration and production activities. These include exchange traded and over-the-counter (OTC) crude put spread options and three way collars with the underlying contract and settlement pricings based on NYMEX West Texas Intermediate (WTI) and Henry Hub. Options and collars are used to establish a floor price, or floor and ceiling prices, for expected future oil and natural gas sales.

The Company uses put spread options to manage commodity price risk for WTI. A put spread option is a combination of two options: a purchased put and a sold put. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price plus the excess of the purchased put strike price over the sold put strike price.

The Company uses three way collars to manage commodity price risk for both oil and natural gas production. A three way collar is a combination of three options: a sold call, a purchased put and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price plus the excess of the purchased put strike price over the sold put strike price.

As of December 31, 2014, the Company had entered into derivative contracts through June 2017 covering a total of approximately 9,680 MBbls of our projected oil production through the purchases of put spreads and three way collars. The Company also entered into three way collars through December 2015 covering approximately 3,300 MMBtu of our projected natural gas production.

Derivative Activities

The following table summarizes the open positions for the commodity derivative instruments held by the Company at December 31, 2014:

Crude Options	Notional (MBbl)		Weighted Average Strike Price
Purchased			
Puts	9,680	$	67.91
Calls	—	$	—
Sold			
Puts	(9,680)	$	50.86
Calls	(2,405)	$	114.69

Natural Gas	Notional (MMBtu)		Weighted Average Strike Price
Purchased			
Puts	3,300	$	4.50
Calls	—	$	—
Sold			
Puts	(3,300)	$	3.75
Calls	(3,300)	$	5.25

During the fourth quarter 2014, Parsley elected to lower certain strike prices for both long and short put positions. The Company primarily focused on positions in late 2015 and 2016. In lowering the strike prices for the put spreads, the Company collected approximately $45.5 million of cash which is reflected in our year-end cash balance.

The Company excluded from the table above 6,700 notional MBbls with a fair value of $144.9 million relating to amounts recognized under the master netting agreement with the derivative counterparty.

Effect of Derivative Instruments on the Consolidated and Combined Financial Statements

Consolidated and Combined Balance Sheets

The following table summarizes the gross fair values of the Company's commodity derivative instruments as of the reporting dates indicated (in thousands):

	December 31,			
		2014		2013
Short-term derivative instruments	$	80,911	$	6,999
Long-term derivative instruments		70,805		13,850
Total derivative instruments - asset		151,716		20,849
Short-term derivative instruments		(29,326)		(4,435)
Long-term derivative instruments		(31,275)		(2,208)
Total derivative instruments - liability		(60,601)		(6,643)
Net commodity derivative asset	$	91,115	$	14,206

Consolidated and Combined Statements of Operation

The Company recognized a gain from its derivative activities of $83.9 million for the year ended December 31, 2014 and losses of $9.8 million and $2.2 million for the years ended December 31, 2013, and 2012, respectively. These gains and losses are included in the Consolidated and Combined Statements of Operations line item, *Derivative income (loss)*, as they were not designated as hedges for accounting purposes for any of the periods presented. The fair value of the derivative instruments is discussed in *Note 14—Disclosures about Fair Value of Financial Instruments.*

Offsetting of Derivative Assets and Liabilities

The Company has agreements in place with all its counterparties that allow for the financial right of offset for derivative assets and liabilities at settlement or in the event of default under the agreements. Additionally, the Company maintains accounts with its brokers to facilitate financial derivative transactions in support of its risk management activities. Based on the value of the Company's positions in these accounts and the associated margin requirements, the Company may be required to deposit cash into these broker accounts. During 2014, the Company did not post margins with any of its counterparties. During 2013, the Company posted margins with some of its counterparties to collateralize certain derivative positions.

The following table presents the Company's net exposure from its offsetting derivative asset and liability positions, as well as cash collateral on deposit with the brokers as of the reporting dates indicated (in thousands):

	Gross Amount Presented on Balance Sheet	Netting Adjustments	Cash Collateral Posted (Received)	Net Exposure
December 31, 2014				
Derivative assets with right of offset or master netting agreements	$ 151,716	$ (60,601)	$ —	$ 91,115
Derivative liabilities with right of offset or master netting agreements	(60,601)	60,601	—	—
December 31, 2013				
Derivative assets with right of offset or master netting agreements	$ 20,849	$ (6,643)	$ 524	$ 14,730
Derivative liabilities with right of offset or master netting agreements	(6,643)	6,643	—	—

Concentration of Credit Risk

The financial integrity of the Company's exchange traded contracts is assured by NYMEX through systems of financial safeguards and transaction guarantees, and is therefore subject to nominal credit risk. Over-the-counter traded options expose the Company to counterparty credit risk. These OTC options are entered into with a large multinational financial institution with investment grade credit rating or through brokers that require all the transaction parties to collateralize their open option positions. The gross and net credit exposure from our commodity derivative contracts as of December 31, 2014 and 2013 is summarized in the table above.

The Company monitors the creditworthiness of its counterparties, established credit limits according to the Company's credit policies and guidelines, and assesses the impact on fair values of its counterparties' creditworthiness. The Company has netting agreements with its counterparties and brokers that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset realized gains against realized losses when settling with derivative counterparties. The Company did not incur any losses due to counterparty bankruptcy filings during any of the years ended December 31, 2014, 2013 or 2012.

Credit Risk Related Contingent Features in Derivatives

Certain commodity derivative instruments contain provisions that require the Company to either post additional collateral or immediately settle any outstanding liability balances upon the occurrence of a specified credit risk related event. These events, which are defined by the existing commodity derivative contracts, are primarily downgrades in the credit ratings of the Company and its affiliates. None of the Company's commodity derivative instruments were in a net liability position with respect to any individual counterparty at December 31, 2014 and 2013. During 2013, the Company received and posted margins with some of its counterparties to collateralize certain derivative positions.

NOTE 5. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties includes the following (in thousands):

	December 31, 2014	December 31, 2013
Oil and natural gas properties:		
Subject to depletion	$ 1,248,376	$ 546,072
Not subject to depletion-acquisition costs		
Incurred in 2014	562,046	—
Incurred in 2013	62,194	65,666
Incurred in 2012	—	2,577
Total not subject to depletion	624,240	68,243
Gross oil and natural gas properties	1,872,616	614,315
Less accumulated depreciation and depletion	(128,044)	(34,957)
Oil and natural gas properties, net	1,744,572	579,358
Other property and equipment	19,177	8,890
Less accumulated depreciation	(2,887)	(1,365)
Other property and equipment, net	16,290	7,525
Property and equipment, net	$ 1,760,862	$ 586,883

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. Costs subject to depletion are proved costs and costs not subject to depletion are unproved costs. At December 31, 2014, the Company had excluded $624.2 million of capitalized costs from depletion. Depletion expense on capitalized oil and gas property was $92.8 million, $27.1, and $6.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Company had no exploratory wells in progress at December 31, 2014 and December 31, 2013.

The Company capitalizes interest on expenditures made in connection with long term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the company has incurred interest expense. During the years ended December 31, 2014, 2013, and 2012, the Company capitalized interest of $2.7 million, $3.4 million, and $1.0 million, respectively.

Depreciation expense on other property and equipment was $1.5 million, $1.1 million, and $0.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

NOTE 6. ACQUISITIONS OF OIL AND GAS PROPERTIES

The following acquisitions were accounted for using the acquisition method under ASC Topic 805, "*Business Combinations,*" which requires the assets acquired and liabilities assumed to be recorded at fair values as of the respective acquisition dates.

During 2012, the Company acquired, from unaffiliated individuals and entities, additional working interests in wells it operates through a number of separate, individually negotiated transactions for an aggregate total cash consideration of $9.7 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties.

In October 2012, the Company acquired, from Diamond K Production, LLC, an entity owned by Diamond K Interests, LP, a member of Parsley LLC, additional working interests in wells it operates for an aggregate cash consideration of $8.2 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties.

During 2013, the Company acquired, from certain of its directors and officers, additional working interests in wells it operates through a number of separate, individually negotiated transactions for an aggregate cash consideration of $19.4 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties. The revenues and operating expenses attributable to the individual acquisitions during the years ended December 31, 2014 and 2013 were not material.

During 2013, the Company acquired, from unaffiliated individuals and entities, additional working interests in wells it operates through a number of separate, individually negotiated transactions for an aggregate total cash consideration of $25.1 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties. The revenues and operating expenses attributable to the individual acquisitions during the years ended December 31, 2014 and 2013 were not material.

In October 2013, the Company acquired oil and gas properties including 5,818 gross (5,330 net) acres primarily in Upton and Reagan Counties, Texas. The Company's total consideration paid was $18.0 million. The revenues and operating expenses attributable to the acquisition during the years ended December 31, 2014 and 2013 were not material. The following table summarizes the purchase price and the value of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	14,734
Unproved oil and gas properties		4,729
Total fair value of oil and gas properties acquired		19,463
Asset retirement obligation		(1,462)
Fair value of net assets acquired	$	18,001

In December 2013, the Company acquired oil and gas properties including 3,250 gross (2,595 net) acres in Upton and Reagan Counties, Texas. The Company's total consideration paid was $32.3 million. The revenues and operating expenses attributable to the acquisition during the years ended December 31, 2014 and 2013 were not material. The following table summarizes the purchase price and the values of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	24,365
Unproved oil and gas properties		8,062
Total fair value of oil and gas properties acquired		32,427
Asset retirement obligation		(167)
Fair value of net assets acquired	$	32,260

On December 30, 2013, the Company acquired non-operated working interests in a number of wells which it currently operates for $80.0 million (the "Merit Acquisition"). The transaction did not increase The Company's gross acreage position, but increases its net acreage by 637 acres in Upton County, Texas. The following table summarizes the purchase price and the values of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	54,440
Unproved oil and gas properties		26,358
Total fair value of oil and gas properties acquired		80,798
Asset retirement obligation		(792)
Fair value of net assets acquired	$	80,006

The following table presents operating revenues and net earnings included in the Company's Consolidated and Combined Statements of Operations for the year ended December 31, 2014 as a result of the Merit Acquisition described above. The revenues and operating expenses attributable to the Merit Acquisition during the year ended December 31, 2013 were not material.

		Year Ended December 31, 2014
		(in thousands)
Total operating revenues	$	39,324
Total operating expenses		7,001
Operating income	$	32,323

On March 27, 2014, the Company entered into a purchase and sale agreement, effective May 1, 2014, pursuant to which it agreed to acquire 2,240 gross (2,005 net) acres in its Midland Basin-Core area and seven gross (6.3 net) wells for total consideration of $165.3 million (the "Pacer Acquisition"), including purchase price adjustments. The following table summarizes the purchase price and the values of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	56,870
Unproved oil and gas properties		108,583
Total fair value of oil and gas properties acquired		165,453
Asset retirement obligation		(172)
Fair value of net assets acquired	$	165,281

The following table presents operating revenues and net earnings included in the Company's Consolidated and Combined Statements of Operations for the year ended December 31, 2014 as a result of the Pacer Acquisition described above. There were no earnings included in the Consolidated and Combined Statements of Operations for the year ended December 31, 2013.

		Year Ended December 31, 2014
		(in thousands)
Total operating revenues	$	19,401
Total operating expenses		3,111
Operating income	$	16,290

On May 30, 2014, the Company entered into the First Amendment to Option Agreement to which the Company acquired an option to purchase 4,640 gross (4,640 net) acres in its Midland Basin-Core area for total consideration of $127.6 million (the "OGX Acquisition", net of purchase price adjustments. On June 4, 2014, the option was exercised. The revenues and operating expenses attributable to the OGX Acquisition during the years ended December 31, 2014 and 2013 were not material. The following table summarizes the purchase price and the values of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	10,747
Unproved oil and gas properties		116,919
Total fair value of oil and gas properties acquired		127,666
Asset retirement obligation		(38)
Fair value of net assets acquired		127,628

On September 30, 2014, the Company entered into a purchase and sale agreement, effective September 1, 2014, pursuant to which it agreed to acquire 4,320 gross (4,228 net) acres and 9 gross (9 net) wells in its Midland Basin-Core area for total consideration of $239.5 million (the "Cimarex Acquisition"), net of purchase price adjustments. The revenues and operating expenses attributable to the Cimarex Acquisition during the years ended December 31, 2014 and 2013 were not material. The following table summarizes the purchase price and the values of assets acquired and liabilities assumed (in thousands):

Consideration given		
Allocation of purchase price		
Proved oil and gas properties	$	111,003
Unproved oil and gas properties		128,756
Total fair value of oil and gas properties acquired		239,759
Asset retirement obligation		(219)
Fair value of net assets acquired		239,540

On December 16, 2014, the Company purchased 8,643 gross (7,128 net) unproved acres in our Midland Basin – Core area for total consideration of $120.0 million from unaffiliated third parties (the "APC Acquisition").

The Company incurred a total of $54.0 million and $32.7 million of leasehold acquisition costs during 2014 and 2013, which are included as part of costs not subject to depletion.

During 2014, the Company acquired, from unaffiliated individuals and entities, additional working interests in wells it operates through a number of separate, individually negotiated transactions for an aggregate total cash consideration of $55.2 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties.

Pro forma for information for material acquisitions (unaudited)

The Merit Acquisition and the Pacer acquisition (collectively, the "Material Acquisitions") were deemed material for purposes of the following pro forma disclosures. The Material Acquisitions were not included in the Company's consolidated results until their closing dates. For the periods after the closing date of each Material Acquisition to December 31, 2014, the Material Acquisitions contributed revenue of $58.7 million and operating income of $48.6 million for the year ended December 31, 2014.

The operating income attributable to the Material Acquisitions does not reflect certain expenses, such as general and administrative and interest expense; therefore, this information is not intended to report results as if these operations were managed on a stand-alone basis. The financial information was derived from the Company's audited historical consolidated financial statements for the years ended December 31, 2014 and 2013, the Material Acquisitions' audited and historical financial statements for the year ended December 31, 2013 and the Material Acquisitions' unaudited interim financial statements from January 1, 2013 to each closing date. The following unaudited pro forma consolidated financial information has been prepared as if the Material Acquisitions occurred on January 1, 2013 for the years ending December 31, (in thousands, except per share data).

	Pro Forma	
	2014	2013
Revenue		
As reported	$ 301,757	$ 121,018
Pro forma	$ 307,999	$ 143,443
Net Income		
As reported	$ 23,429	$ 27,510
Pro forma	$ 24,894	$ 29,452
Basic net income per share		
As reported	$ 0.42	$ 0.32
Pro forma	$ 0.45	$ 0.34
Diluted net income per share		
As reported	$ 0.42	$ 0.23
Pro forma	$ 0.45	$ 0.25

These pro-forma adjustments have been calculated after applying the Company's accounting policies and adjusting the results to reflect additional depreciation and amortization that would have been charged assuming the properties were acquired and fair value adjustments to property and equipment had been applied. In addition, pro forma adjustments have been made for the interest that would have been incurred for financing the acquisitions with the Company's credit facility. These pro forma results of operations have been prepared for comparative purposes only and they do not purport to be indicative of the results of operations that actually would have resulted had the acquisitions occurred on the date indicated or that may result in the future.

NOTE 7. SALES OF OIL AND NATURAL GAS PROPERTIES

In April 2012, The Company sold 2,652 net unevaluated acres in Dawson, Glasscock, Howard, Martin and Upton Counties, Texas for $8.6 million and realized a $7.5 million gain on the sale.

In November 2012, The Company sold 960 net unevaluated acres in Howard County, Texas for total proceeds of $0.7 million and realized a $0.3 million gain on the sale.

In August 2013, The Company sold its interest in seven non-operated wells and 190 net acres for total proceeds of $0.8 million and realized a $36,000 gain on the sale.

In August 2014, the Company sold its interest in one operated well and 38 net acres for total proceeds of $0.2 million and realized a $2.1 million loss on the sale.

NOTE 8. EQUITY INVESTMENT

The Company uses the equity method of accounting for the investment in SPS, with earnings or losses, after adjustment for intra-company profits and losses, reported in the income (loss) from equity investment line on the Consolidated and Combined Statements of Operations.

In November 2014, SPS underwent a corporate reorganization, effective January 1, 2014, in which two nonrelated parties were admitted as members, each obtaining a 7.5% interest in exchange for a capital contributions. As a result of the reorganization, the Company's interest in SPS was decreased to 42.5%

As of December 31, 2014 and December 31, 2013, the balance of the Company's investment in SPS was $2.2 million and $1.8 million, respectively. The investment balance increased by $1.1 million and $0.7 million for the years ended December 31, 2014 and 2013, for the Company's share of SPS' net income, before adjustment for intra-company profits and losses, respectively. During the years ended December 31, 2014 and 2013, SPS provided services to the Company in its oil and natural gas field development operations, which the Company capitalized as part of its oil and gas properties. As such, that portion of the Company's share of SPS' gross profit from these services totaling $0.7 million and $0.5 million for the years ended December 31, 2014 and 2013, was subsequently eliminated from its share of SPS's net income and a corresponding reduction was made to the carrying value of its investment.

NOTE 9. DEBT

The Company's debt consists of the following (in thousands):

	December 31,	
	2014	2013
Revolving credit agreement	$ 120,000	$ 234,750
Senior unsecured notes	550,000	—
Capital leases	2,069	—
Second lien term loan	—	192,854
Aircraft term loan	—	2,593
Total debt	672,069	430,197
Premium on senior unsecured notes	5,426	—
Less: current portion	(650)	(227)
Total long-term debt	$ 676,845	$ 429,970

First Lien Obligations

Western National Bank Facility

On July 26, 2010, the Company entered into a loan agreement with Western National Bank which was subsequently amended and extended multiple times. On September 10, 2013, the Company repaid all amounts outstanding plus accrued interest associated the the Western National Bank facility.

Revolving Credit Agreement

On September 10, 2013, the Company entered into the Revolving Credit Agreement with Wells Fargo Bank National Association as the administrative agent. The Revolving Credit Agreement provides a revolving credit facility with a borrowing capacity up to the lesser of (i) the borrowing base (as defined in the Revolving Credit Agreement), (ii) aggregate lender commitments, and (iii) $750.0 million. The Revolving Credit Agreement matures on September 10, 2018. The Revolving Credit Agreement is secured by substantially all of the Company's assets.

The Revolving Credit Agreement provided for an initial borrowing base of $175.0 million based on the Company's proved producing reserves and a portion of its proved undeveloped reserves. The borrowing base will be redetermined by the lenders at least semi-annually on each April 1 and October 1, with the next redetermination on April 1, 2015. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Revolving Credit Agreement.

On October 21, 2013, the Company entered into an amended and restated credit agreement (as amended, the "Revolving Credit Agreement"), whereby the borrowing base was reduced from $175.0 million to $143.8 million. On December 20, 2013, The Company entered into the First Amendment to the Amended and Restated Credit Agreement which increased the borrowing base from $143.8 million to $240 million. In addition, the amendment provided that the borrowing base would automatically increase from $240 million to $280 million upon the closing of the Merit Acquisition, which closed on December 30, 2013.

On April 15, 2014, in connection with the issuance of the Notes (as defined herein) offering, the Company entered into the Third Amendment to the Amended and Restated Credit Agreement whereby the borrowing base was increased from $227.5 million to $365.0 million. Immediately following the Notes offering, the borrowing base was reduced to $327.5 million.

On May 2, 2014, the Company entered into the Fourth Amendment to the Revolving Credit Agreement whereby the expiration date of any letter of credit was increased from fifteen months to eighteen months.

On May 9, 2014, the Company entered into the Fifth Amendment to the Revolving Credit Agreement whereby certain terms were amended permitting the Corporate Reorganization to occur.

On May 29, 2014, the Company used proceeds from the Offering to repay the outstanding borrowings under the Revolving Credit Agreement.

On September 4, 2014, the Company entered into the Sixth Amendment to the Revolving Credit Agreement (the “Sixth Amendment”.) The Sixth Amendment changed the reporting requirements and deliverables in response to the Company becoming a public company.

In November 2014, the Company entered into the Seventh Amendment to the Amended and Restated Credit Agreement whereby the borrowing base was increased to $575.0 million, with a commitment level of $365.0 million.

In December 2014, the Company’s borrowing base was decreased to $562.0 million, with a commitment level of $365.0 million, resulting from a restructuring of commodity price hedges. In February 2015, the borrowing base was decreased to $560.8, with a commitment level of $365.0 also resulting from restructuring of commodity price hedges.

As of December 31, 2014 there were $120.0 million of borrowings outstanding and $0.3 million in letters of credit outstanding, resulting in availability of $244.7 million.

Borrowings under the Revolving Credit Agreement can be made in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBO rate (equal to the product of: (a) the LIBO rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the aggregate of the maximum reserve percentages (expressed as a decimal) on such date at which the Administrative Agent is required to maintain reserves on ‘Eurocurrency Liabilities’ as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted LIBO rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The Revolving Credit Agreement also provides for a commitment fee ranging from 0.375% to 0.500%, depending on the percentage of our borrowing base utilized. As of December 31, 2014, letters of credit outstanding under the Revolving Credit Agreement had a weighted average interest rate of 1.75%. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The Revolving Credit Agreement requires the Company to maintain the following two financial ratios:

- a current ratio, which is the ratio of consolidated current assets (including unused availability under its revolving credit facility) to consolidated current liabilities of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of EBITDAX to interest expense, of not less than 2.5 to 1.0 as of the last day of any fiscal quarter for the four fiscal quarters ending on such date.

The Revolving Credit Agreement also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

At December 31, 2014, the Company was in compliance with all required covenants. The Revolving Credit Agreement is subject to customary events of default, including a change in control (as defined in the Revolving Credit Agreement). If an event of default occurs and is continuing, the Majority Lenders (as defined in the Revolving Credit Agreement) may accelerate any amounts outstanding.

7.500% Senior Notes due 2022

On February 5, 2014, Parsley LLC and Finance Corp. issued $400 million of 7.500% senior notes due 2022 (the "Notes"). Interest is payable on the Notes semi-annually in arrears on each February 15 and August 15, and commenced August 15, 2014. These notes are guaranteed on a senior unsecured basis by all of our subsidiaries, other than Parsley LLC and Finance Corp. The issuance of the Notes resulted in net proceeds, after discounts and offering expenses, of approximately $391.4 million, $198.5 million of which was used repay all outstanding term debt, accrued interest and a prepayment penalty under a second lien credit facility (which was terminated concurrently with such repayment) and $175.1 million of which was used to partially repay amounts outstanding, plus accrued interest, under the Revolving Credit Agreement.

On April 14, 2014, Parsley LLC and Finance Corp. issued an additional $150 million of the Notes at 104% of par for gross proceeds of $156 million. The issuance of these notes resulted in net proceeds of approximately $152.8 million, after deducting the initial purchasers' discount and estimated offering expenses, $145 million of which was used to repay borrowings under the Revolving Credit Agreement.

At any time prior to February 15, 2017, the Company may redeem up to 35% of the Notes at a redemption price of 107.5% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 120 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to February 15, 2017, the Company may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 15, 2017, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 105.625% for the twelve-month period beginning on February 15, 2017, 103.750% for the twelve-month period beginning February 15, 2018, 101.875% for the twelve-month period beginning on February 15, 2019 and 100.00% beginning on February 15, 2020, plus accrued and unpaid interest to the redemption date.

The indenture governing the Notes restricts our ability and the ability of certain of our subsidiaries to, among other things: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications. At December 31, 2014, the Company was in compliance with all of these covenants. If at any time when the Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no default or event of default (as defined in the Indenture) has occurred and is continuing, many of such covenants will be suspended. If the ratings on the Notes were to decline subsequently to below investment grade, the suspended covenants will be reinstated.

Second Lien Agreement

On November 20, 2012, The Company entered into a second lien credit agreement (the "Second Lien Agreement") providing for term loans up to an aggregate principal amount of $75.0 million and an original maturity date of December 31, 2016. Obligations under the Second Lien Agreement were secured by a second lien on substantially all of the Company's oil and natural gas properties.

The Second Lien Agreement may be prepaid at any time. If prepaid prior to November 20, 2014, The Company will be obligated to pay a prepayment premium equal to 7.5% of the principal amount being prepaid. As a condition to entering into the Second Lien Agreement, The Company was required to enter into certain derivative instruments to hedge not less than 80% of the anticipated projected production from proved, developed, producing oil and natural gas properties.

On June 10, 2013, the Company entered into a First Amendment and Waiver to the Second Lien Agreement (the "First Amendment"). The First Amendment: (1) reduced the Consolidated Current Ratio, as at June 30, 2013, to be not less than 0.75:1.00, and as at the last day of any quarter thereafter, to be not less than 1.00:1.00; (2) provided a waiver of the Lenders' right to assert an Event of Default with respect to the Consolidated Current Ratio covenant as of March 31, 2013; and (3) extended the deadline of delivery of required financial statements from 120 days to 180 days after The Company's year-end (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the Second Lien Term Agreement).

On September 10, 2013, the Company entered into a Second Amendment and Waiver to the Second Lien Agreement (the "Second Amendment"). The Second Amendment: (1) amended the definition of the Consolidated Current Ratio to allow for the inclusion, in the numerator, of unused borrowing capacity under the Syndicated Credit Agreement; and (2) waived the Lenders' right to assert an Event of Default with respect to the Consolidated Current Ratio covenant as of June 30, 2013 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the Second Lien Agreement agreement).

On October 21, 2013, the Company entered into an amended and restated second lien credit agreement (the "Amended Second Lien Agreement"). The Amended Second Lien Agreement created two tranches of loan commitments, the Tranche A Commitment totaling $75.0 million and the Tranche B Commitment, totaling $125.0 million. The maturity date remains December 31, 2016.

Tranche A borrowings bore interest at the combined rate equal to (i) the greater of 1.0%, and the three- month LIBO rate, plus 10.0%, paid in cash, plus (ii) 4.0% paid-in-kind by adding to the principal balance outstanding. Tranche B borrowings bore interest at the greater of 1.0%, and the three-month LIBO rate, plus 11.0%, paid in cash.

The Second Lien Agreement was repaid in full in February 2014. The Company paid a prepayment penalty equal to 7.5% of the principal amount being repaid.

Aircraft Term Loan

On April 2, 2013, the Company entered into a $2.8 million term loan ("Aircraft Term Loan") in connection with the purchase of a corporate aircraft. The Company repaid the Aircraft Term Loan in full in August 2014.

Capital Lease

During the year ended December 31, 2014, the Company entered into an aggregate of $2.3 million in capital lease agreements payable ("Capital Leases") in connection with the lease of vehicles for operations and field personnel. The Capital Leases bear interest at annual rates ranging from 5.0% to 6.7% with varying maturities between March 2017 and August 2018. The Capital Leases require monthly payments of $58,426 of principal and interest.

Principal maturities of long-term debt

Principal maturities of long-term debt outstanding, excluding the premium on the Notes, at December 31, 2014 are as follows (in thousands):

2015	$ 650
2016	688
2017	705
2018	120,026
2019	—
Thereafter	550,000
Total	$ 672,069

Interest expense

The following amounts have been incurred and charged to interest expense for the year ended December 31, 2014, 2013, and 2012 (in thousands):

	For the Year Ended December 31,		
	2014	2013	2012
Cash payments for interest	$ 26,235	$ 13,536	$ 4,661
Change in interest accrual	13,390	—	—
Payment-in-kind interest	234	2,597	1,845
Amortization of deferred loan origination costs	1,941	405	80
Amortization of original issue discount	—	—	158
Write-off of deferred loan origination costs	386	820	615
Amortization of bond premium	(574)	—	—
Interest income	(316)	(235)	(75)
Interest costs incurred	41,296	17,123	7,284
Less: capitalized interest	(2,689)	(3,409)	(999)
Total interest expense	$ 38,607	$ 13,714	$ 6,285

NOTE 10. EQUITY

Preferred Stock

Pursuant to the Company's Bylaws, the Company's board of directors, subject to any limitations prescribed by law, may, without further stockholder approval, establish and issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50.0 million shares of preferred stock. The Company had no shares of preferred stock outstanding at December 31, 2014.

Class A Common Stock

As a result of the Offering and the Corporate Reorganization, the Company has a total of 93.9 million shares of its Class A Common Stock outstanding as of December 31, 2014, which includes 0.8 million shares of restricted stock and restricted stock units. Holders of Class A Common Stock are entitled to one vote per share on all matters to be voted upon by the stockholders and are entitled to ratably receive dividends when and if declared by the Company's board of directors. Upon liquidation, dissolution, distribution of assets or other winding up, the holders of Class A Common Stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and the liquidation preference of any of our outstanding shares of preferred stock.

Class B Common Stock

As a result of the Corporate Reorganization, the Company has a total of 32.1 million shares of its Class B Common Stock outstanding as of December 31, 2014. Holders of the Class B Common Stock are entitled to one vote per share on all matters to be voted upon by the stockholders. Holders of Class A Common Stock and Class B Common Stock vote together as a single class on all matters presented to the Company's stockholders for their vote or approval, except with respect to the amendment of certain provisions of the Company's certificate of incorporation that would alter or change the powers, preferences or special rights of the Class B Common Stock so as to affect them adversely, which amendments must be by a majority of the votes entitled to be cast by the holders of the shares affected by the amendment, voting as a separate class, or as otherwise required by applicable law.

Holders of Class B Common Stock do not have any right to receive dividends, unless the dividend consists of shares of Class B Common Stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class B Common Stock paid proportionally with respect to each outstanding share of Class B Common Stock and a dividend consisting of shares of Class A Common Stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class A Common Stock on the same terms is simultaneously paid to the holders of Class A Common Stock. Holders of Class B Common Stock do not have any right to receive a distribution upon a liquidation or winding up of the Company.

The PE Unit Holders generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of Class B Common Stock), for shares of the Company's Class A Common Stock at an exchange ratio of one share of Class A Common Stock for each PE Unit (and a corresponding number of shares of Class B Common Stock) exchanged, (subject to conversion rate adjustments for stock splits, stock dividends, and reclassifications) or cash at the Company's or Parsley LLC's election (the "Cash Option"). During the year ended December 31, 2014, no PE Unit Holders elected to exchange pursuant to their Exchange Right.

Earnings per Share

Basic earnings per share ("EPS") measures the performance of an entity over the reporting period. Diluted earnings per share measures the performance of an entity over the reporting period while giving effect to all potentially dilutive common shares that were outstanding during the period. The Company uses the "if-converted" method to determine the potential dilutive effect of its Class B Common Stock and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock and restricted stock units. For the year ended December 31, 2014, Class B Common Stock was not recognized in dilutive earnings per share as the effect would be antidilutive.

The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

		December 31, 2014
Basic EPS (in thousands, except per share data)		
Numerator:		
Basic net income attributable to Parsley Energy Inc. Stockholders	$	23,429
Denominator:		
Basic weighted average shares outstanding		55,136
Basic EPS attributable to Parsley Energy Inc. Stockholders	$	0.42
Diluted EPS		
Numerator:		
Net income attributable to Parsley Energy Inc. Stockholders		23,429
Effect of conversion of the shares of Company's Class B Common stock to shares of the Company's Class A common stock		—
Diluted net income attributable to Parsley Energy Inc. Stockholders	$	23,429
Denominator:		
Basic weighted average shares outstanding		55,136
Effect of dilutive securities:		
Class B Common Stock		—
Restricted Stock and Restricted Stock Units		103
Diluted weighted average shares outstanding		55,239
Diluted EPS attributable to Parsley Energy Inc. Stockholders	$	0.42

LLC Interest Issuance

On June 11, 2013, Parsley LLC issued membership interests to NGP X US Holdings, L.P. and other investors for total consideration of $73.5 million. These interest holders were designated as "Preferred Holders" and granted certain rights in the limited liability agreement of Parsley LLC (the "Parsley LLC Agreement"). Included with these rights were (1) the right to receive a 9.5% return on their invested capital prior to any distribution to any other unit holders (the "Preferred Return") and (2) the right to require Parsley LLC to redeem all, but not less than all, of each Preferred Holder's interest in Parsley LLC after the seventh anniversary, but before the eighth anniversary, of the date of their investment, or if Bryan Sheffield ceased to be Parsley LLC's Chief Executive Officer.

As the investment by the Preferred Holders was redeemable at their option, the Company reflected this investment outside of permanent equity, under the heading "*Mezzanine Equity—Redeemable LLC Units*" in Parsley LLC's Consolidated and Combined Balance Sheet at December 31, 2013, in accordance with ASC Topic 480, *"Distinguishing Liabilities from Equity"*.

On May 29, 2014, in connection with the Corporate Reorganization, the Preferred Holders' interests were converted to PE Units. A portion of such PE Units were redeemed by Parsley LLC in exchange for the Preferred Return payment of approximately $6.7 million and the remainder of such PE Units were contributed to the Company in exchange for an equal number of shares of Class A Common Stock.

Incentive Units

Pursuant to the Parsley LLC Agreement, certain incentive units were issued to legacy investors, management and employees of Parsley LLC. The incentive units were intended to be compensation for services rendered to Parsley LLC. The original terms of the incentive units were as follows: Tier I incentive units vested ratably over three years, but were subject to forfeiture if payout was not achieved. In addition, all unvested Tier I incentive units vested immediately upon Tier I payout. Tier I payout was realized upon the return of the Preferred Holders' invested capital and a specified rate of return. Tier II, III and IV incentive units vested only upon the achievement of certain payout thresholds for each such tier and each tier of the incentive units was subject to forfeiture if the applicable required payouts were not achieved. In addition, vested and unvested incentive units would be forfeited if an incentive unit holder's employment was terminated for any reason or if the incentive unit holder voluntarily terminated their employment.

The incentive units were accounted for as liability-classified awards pursuant to ASC Topic 718, *"Compensation—Stock Compensation,"* as achievement of the payout conditions required the settlement of such awards by transferring cash to the incentive unit holder. As such, the fair value of the incentive unit was remeasured each reporting period through the date of settlement, with the percentage of such fair value recorded to compensation expense each period being equal to the percentage of the requisite explicit or implied service period that has been rendered at that date.

In connection with the Corporate Reorganization, all of the incentive units were immediately vested and converted into PE Units and, subsequently, a portion of such PE Units were exchanged on a one for one basis for shares of Class A Common Stock. As a result, Parsley LLC was required to recognize, as a non-cash charge, the unrecognized cumulative incentive unit compensation expense of approximately $50.6 million on May 29, 2014, in addition to the $0.5 million recognized during the period from January 1, 2014 through May 29, 2014.

Restricted Stock and Restricted Stock Unit Awards

Restricted stock awards are awards of Class A Common Stock that are subject to restrictions on transfer and to a risk of forfeiture if the award recipient is no longer an employee or director of the Company for any reason prior to the lapse of the restrictions. Restricted stock unit awards are awards of restricted stock units that are subject to restrictions on transfer and to a risk of forfeiture if the award recipient is no longer an employee or director of the Company for any reason prior to the lapse of the restriction. Each restricted stock unit represents the right to receive one share of Class A Common Stock. The fair value of such restricted stock and restricted stock units was determined using the weighted average closing price on the grant date and compensation expense, net of estimated forfeitures, is recorded over the applicable vesting periods.

The following table summarized the Company's restricted stock and restricted stock unit award activity for the year ended December 31, 2014:

	Number of Shares (in thousands)	Weighted - Average Grant Date Fair Value
Outstanding at January 1, 2014	—	$ —
Restricted Stock Granted	770	$ 18.54
Restricted Stock Units Granted	24	$ 18.50
Vested	—	$ —
Forfeited	(37)	$ 18.50
Outstanding at December 31, 2014	757	$ 18.54

Stock based compensation expense related to restricted stock and restricted stock units was $2.2 million for the year ended December 31, 2014, respectively. There was approximately $11.8 million of unamortized compensation expense relating to outstanding restricted stock and restricted stock units at December 31, 2014.

Noncontrolling Interest

As a result of the Corporate Reorganization and the Offering, the Company acquired 74.3% of Parsley LLC, with the Existing Owners retaining ownership of 25.7% of Parsley LLC. As a result, the Company has consolidated the financial position and results of operations of Parsley LLC and reflected that portion retained by the Existing Owners as a noncontrolling interest.

Net income attributable to noncontrolling interest for the year ended December 31, 2014 of approximately $33.3 million represents the net income of Parsley LLC attributable to the Existing Owners' retained interest since May 29, 2014.

NOTE 11. INCOME TAXES

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. The Company believes it is more likely than not that certain net operating losses can be carried forward and utilized.

Parsley LLC, the Company's accounting predecessor, is a limited liability company that is not subject to U.S. federal income tax. As part of the Corporate Reorganization, certain of the Existing Owners exchanged all or part of their PE Units for shares of the Company's common stock, as discussed in *Note 1 – Organization and Nature of Operations*. On the date of the Corporate Reorganization, a corresponding "first day" tax charge of approximately $95.5 million was recorded to establish a net deferred tax liability for differences between the tax and book basis of Parsley LLC's assets and liabilities. In addition, the Company recorded a long term liability of $56.3 million to establish the TRA (as defined herein) and a corresponding deferred tax asset of $66.3 million. The offset of the deferred tax liability, TRA, and deferred tax asset was recorded to additional paid-in capital. Subsequently, in 2014, as part of the tax return preparation process, adjustments were made to reduce the TRA liability by $5.6 million and to reduce the deferred tax asset by $6.7 million with the offset recorded to additional paid in capital. As of December 31, 2014, the liability associated with the TRA was $50.7 million and the corresponding deferred tax asset was $59.6 million.

The components of the income tax provision were as follows for the periods indicated (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Federal:			
Current	$ —	$ —	$ —
Deferred	31,968	—	—
Total federal	31,968	—	—
State, net of federal benefit:			
Deferred	4,500	1,906	554
Total state	4,500	1,906	554
Income tax provision	$ 36,468	$ 1,906	$ 554

The following table reconciles the income tax provision with income tax expense at the federal statutory rate for the periods indicated (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Income (loss) before income taxes	$ 93,190	$ 29,416	$ 13,453
Plus: net loss prior to corporate reorganization	37,378	—	—
Less: net income attributable to noncontrolling interest	(33,293)	—	—
Income (loss) before income taxes and noncontrolling interest subsequent to corporate reorganization	97,275	29,416	13,453
Income taxes at the federal statutory rate	34,046	—	—
State income taxes, net of federal benefit	967	—	—
State income taxes, prior to corporate reorganization	1,246	1,906	554
Provision to return adjustment	170	—	—
Permanent and other	39	—	—
Income tax provision	36,468	1,906	554

The Company has net operating loss carryforwards ("NOLs") for United States income tax purposes that have been generated from our operations. Our NOLs are scheduled to expire if not utilized between 2033 and 2034. NOLs available for utilization as of December 31, 2014 were approximately $144 million.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	December 31,	
	2014	2013
Current:		
Liabilities:		
Derivative fair value gain	(12,601)	—
Total current deferred tax liability	(12,601)	—
Net current deferred tax liability	(12,601)	—
Noncurrent:		
Assets:		
Asset retirement obligations	4,379	—
Materials and supplies	431	—
Deferred stock based compensation	644	—
Net operating loss carryforward	50,425	—
Total noncurrent deferred tax assets	55,879	—
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(108,825)	(2,572)
Derivative fair value gain	(8,874)	—
Earnings in investment in subsidiary	(514)	—
Total noncurrent deferred tax liabilities	(118,213)	(2,572)
Net noncurrent deferred tax liability	(62,334)	(2,572)

NOTE 12. RELATED PARTY TRANSACTIONS

Well Operations

During the years ended December 31, 2014, 2013, and 2012, several of the Company's directors, officers, 5% stockholders, their immediate family, and entities affiliated or controlled by such parties ("Related Party Working Interest Owners") owned non-operated working interests in certain of the oil and natural gas properties that the Company operates. The revenues disbursed to such Related Party Working Interest Owners for the years ended December 31, 2014, 2013, and 2012, totaled $11.3 million, $14.4 million, and $10.8 million, respectively. The revenues disbursed to the Related Party Working Interest Owners for the year ended December 31, 2014 include $2.1 million of revenues for the five months ended May 29, 2014 for entities no longer considered a related party due to their direct relationship with Diamond K (defined herein.)

As a result of this ownership, from time to time, the Company will be in a net receivable or net payable position with these individuals and entities. The Company does not consider any net receivables from these parties to be uncollectible.

Acquisitions

On October 29, 2012, The Company acquired, from Diamond K Production, LLC, an entity owned by Diamond K (defined herein), additional working interests in wells it operates for an aggregate cash consideration of $8.2 million. The Company reflected the total consideration paid as part of its cost subject to depletion within its oil and gas properties.

During the years ended December 31, 2013, The Company acquired, from certain of its directors and officers, additional working interests in wells it operates through a number of separate, individually negotiated transactions for an aggregate total of and $19.4 million, respectively.

Tex-Isle Supply, Inc. Purchases

The Company makes purchases of equipment used in its drilling operations from Tex-Isle Supply, Inc. ("Tex-Isle"). Tex-Isle is controlled by a party who is also the general partner of Diamond K Interests, LP ("Diamond K"), a former member of Parsley LLC. In connection with the Offering, Diamond K exchanged its membership interest for shares of Class A Common Stock. As of May 29, 2014, Diamond K is no longer considered a related party as their ownership interest fell below 5% due to this transaction, which results in Tex-Isle no longer being considered a related party. During the five months ended May 29, 2014, the Company made purchases of equipment used in its drilling operations totaling $29.3 million, from Tex-Isle. During the years ended December 31, 2013 and 2012, the Company made purchases of equipment used in its drilling operations totaling $68.1 million and $31.1 million from Tex-Isle.

Spraberry Production Services LLC

As defined in *Note 8—Equity Investment*, as of December 31, 2014, the Company owns a 42.5% interest in SPS. During the years ended December 31, 2014, 2013 and 2012, the Company incurred charges totaling $5.1 million, $3.3 million, and $2.0 million, respectively, for services performed by SPS for the Company's well operations and drilling activities.

Lone Star Well Service, LLC

The Company makes purchases of equipment used in its drilling operations from Lone Star Well Service, LLC ("Lone Star"). Lone Star is controlled by SPS. During the year ended December 31, 2014, the Company incurred charges totaling $0.7 million, for services performed by Lone Star for the Company's well operations and drilling activities. There were no such charges incurred during 2013 and 2012.

Davis, Gerald, and Cremer

During the years ended December 31, 2014, 2013, and 2012, we incurred charges totaling $0.2 million, $0.3 million, and $0.1 million, respectively, for legal services from Davis, Gerald & Cremer, PC, of which our director David H. Smith is a shareholder.

Exchange Right

In accordance with the terms of the amended Parsley LLC Agreement, the PE Unit Holders generally have the right to exchange their PE Units (and a corresponding number of shares of the Company's Class B Common Stock), for shares of the Company's Class A Common Stock at an exchange ratio of one share of Class A Common Stock for each PE Unit (and a corresponding share of Class B Common Stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends, and reclassifications) or cash (pursuant to the Cash Option). As a PE Unit Holder exchanges its PE Units, the Company's interest in Parsley LLC will be correspondingly increased.

Tax Receivable Agreement

In connection with the Offering, on May 29, 2014, the Company entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC, and certain holders of PE Units prior to the Offering (each such person a "TRA Holder"), including certain executive officers. This agreement generally provides for the payment by the Company of 85% of the net cash savings, if any, in U.S. federal, state, and local income tax or franchise tax that the Company actually realizes (or is deemed to realize in certain circumstances) in periods after the Offering as a result of (i) any tax basis increases resulting from the contribution in connection with the Offering by such TRA Holder of all or a portion of its PE Units to the Company in exchange for shares of Class A Common Stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A Common Stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (ii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The term of the TRA commences on May 29, 2014 and continues until all such tax benefits have been utilized or expired, unless the Company exercises its right to terminate the TRA. If the Company elects to terminate the TRA early, it would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the TRA (based upon certain assumptions and deemed events set forth in the TRA). In addition, payments due under the TRA will be similarly accelerated following certain mergers or other changes of control.

NOTE 13. COMMITMENTS AND CONTINGENCIES

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on The Company's financial position, results of operations or cash flows.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require The Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed or readily determinable. At December 31, 2014 and 2013, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Drilling Commitments

The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company's drilling commitments as of December 31, 2014:

	Payments Due by Period						
(in thousands)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Drilling commitments	39,466	27,911	10,039	—	—	—	77,416

Operating Leases

The estimated future minimum lease payments under long term operating lease agreements as of December 31, 2014 was as follows (in thousands):

	For the years ended December 31,						
	2015	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
	(in thousands)						
Office Leases	$ 2,827	$ 2,831	$ 4,452	$ 4,865	$ 4,977	$ 21,005	$ 40,957
Vehicle Operating Leases	116	124	—	—	—	—	240
Office Equipment	86	70	29	1	—	—	186
	3,029	3,025	4,481	4,866	4,977	21,005	41,383

Rent expense for the years ended December 31, 2014, 2013 and 2012 was $1.5 million, $0.7 million and $0.3 million, respectively.

NOTE 14. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The book value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate their fair value due to the short-term nature of these instruments. The book value of the Company's Revolving Credit Agreement approximates its fair value as the interest rate is variable.

The estimated fair value of the Company's $550 million of Notes at December 31, 2014, was approximately $521.1 million. The fair value of the Notes is classified as a level 1 measurement as it is calculated based on market quotes.

Impairments of long-lived assets – The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value of the properties would be recognized at that time.

The Company calculates the estimated fair values using a discounted future cash flow model. Management's assumptions associated with the calculation of discounted future cash flows include commodity prices based on NYMEX futures price strips (Level 1), as well as Level 3 assumptions including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes and (v) estimated reserves.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to further impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves and (iv) results of future drilling activities.

Financial Assets and Liabilities Measured at Fair Value

Commodity derivative contracts are marked-to-market each quarter and are thus stated at fair value in the accompanying Consolidated and Combined Balance Sheets and in *Note 4—Derivative Financial Instruments*. The company adjusts the valuations from the valuation model for nonperformance risk and for counterparty risk. The fair values of the Company's commodity derivative instruments are classified as level 2 measurements as they are calculated using industry standard models using assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors. The following summarizes the fair value of the Company's derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated (in thousands):

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Commodity derivative contracts				
Assets:				
Short-term derivative instruments	$ —	$ 80,911	$ —	$ 80,911
Long-term derivative instruments	—	70,805	—	70,805
Total derivative instrument - asset	$ —	$ 151,716	$ —	$ 151,716
Liabilities:				
Short-term derivative instruments	$ —	$ (29,326)	$ —	$ (29,326)
Long-term derivative instruments	—	(31,275)	—	(31,275)
Total derivative instruments - liability	—	(60,601)	—	(60,601)
Net commodity derivative asset	$ —	$ 91,115	$ —	$ 91,115

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Commodity derivative contracts				
Assets:				
Short-term derivative instruments	$ —	$ 6,999	$ —	$ 6,999
Long-term derivative instruments	—	13,850	—	13,850
Total derivative instrument - asset	$ —	$ 20,849	$ —	$ 20,849
Liabilities:				
Short-term derivative instruments	$ —	$ (4,435)	$ —	$ (4,435)
Long-term derivative instruments	—	(2,208)	—	(2,208)
Total derivative instruments - liability	—	(6,643)	—	(6,643)
Net commodity derivative asset	$ —	$ 14,206	$ —	$ 14,206

There were no transfers in to or out of level 2 during the years ended December 31, 2014 or 2013.

NOTE 15. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date these financial statements were issued. The Company determined there were no events, other than as described below, that required disclosure or recognition in these financial statements.

Private Placement of Common Stock

On February 5, 2014, the Company entered into an agreement to sell 14,885,797 shares of Class A Common Stock in a private placement at a price of $15.50 per share to selected institutional investors. The Private Placement closed on February 11, 2015 and resulted in approximately $231 million of gross proceeds and approximately $224 million of net proceeds (after deducting placement agent commissions and the Company's estimated expenses. The Company used the net proceeds from the private placement to repay borrowings under its Revolving Credit Agreement and for general corporate purposes.

SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company's oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized Costs

	December 31, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas properties:		
Proved properties	$ 1,248,376	$ 546,072
Unproved properties	624,240	68,243
Total oil and natural gas properties	1,872,616	614,315
Less accumulated depreciation, depletion and amortization	(128,044)	(34,957)
Net oil and natural gas properties capitalized	$ 1,744,572	$ 579,358

Costs Incurred for Oil and Natural Gas Producing Activities

	Year Ended December 31, 2014	2013	2012
		(in thousands)	
Acquisition costs:			
Proved properties	$ 233,899	$ 142,695	$ 17,932
Unproved properties	528,301	65,686	14,022
Development costs	488,673	268,400	71,945
Total	$ 1,250,873	$ 476,781	$ 103,899

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2014, which have been prepared and presented under SEC rules. These rules require SEC reporting companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2014 was based on an unweighted average 12-month average West Texas Intermediate posted price per Bbl for oil and NGLs, and a Henry Hub spot natural gas price per Mcf for natural gas, as set forth in the following table:

	Year Ended December 31, 2014	2013	2012
Oil (per Bbl)	$ 85.99	$ 92.53	$ 89.71
Natural gas liquids (per Bbl)	$ 35.27	$ 36.20	$ 35.02
Natural gas (per Mcf)	$ 4.28	$ 3.46	$ 2.48

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement has limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of West Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of West Texas. All of the estimates of the proved reserves at December 31, 2012 were estimated by the Company's in-house petroleum engineers, taking into consideration the information and assumptions contained in the December 31, 2013 report prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a roll forward of the total proved reserves for the years ended December 31, 2014, 2013, and 2012, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Year Ended December 31, 2014			
	Crude Oil (Bbls)	Liquids (Bbls)	Natural Gas (Mcf)	Boe
	(in thousands)			
Proved Developed and Undeveloped Reserves:				
Beginning of the year	29,507	12,357	77,818	54,834
Extensions and discoveries	18,776	8,157	41,348	33,824
Revisions of previous estimates	(7,832)	(528)	(6,714)	(9,480)
Purchases of reserves in place	10,006	3,906	18,244	16,953
Divestures of reserves in place	—	—	—	—
Production	(2,840)	(1,225)	(7,051)	(5,240)
End of the year	47,617	22,667	123,645	90,891
Proved Developed Reserves:				
Beginning of the year	13,560	4,762	31,301	23,539
End of the year	23,547	11,491	65,484	45,952
Proved Undeveloped Reserves:				
Beginning of the year	15,947	7,595	46,517	31,295
End of the year	24,070	11,175	58,161	44,939

	Year Ended December 31, 2013			
	Crude Oil (Bbls)	Liquids (Bbls)	Natural Gas (Mcf)	Boe
	(in thousands)			
Proved Developed and Undeveloped Reserves:				
Beginning of the year	12,987	4,732	30,214	22,755
Extensions and discoveries	10,378	4,840	29,489	20,132
Revisions of previous estimates	(2,029)	(796)	(1,813)	(3,127)
Purchases of reserves in place	9,223	3,695	23,937	16,908
Divestures of reserves in place	(3)	(1)	(7)	(5)
Production	(1,049)	(113)	(4,002)	(1,829)
End of the year	29,507	12,357	77,818	54,834
Proved Developed Reserves:				
Beginning of the year	5,834	1,906	12,186	9,771
End of the year	13,560	4,762	31,301	23,539
Proved Undeveloped Reserves:				
Beginning of the year	7,153	2,826	18,028	12,984
End of the year	15,947	7,595	46,517	31,295

	Year Ended December 31, 2012			
	Crude Oil (Bbls)	Liquids (Bbls)	Natural Gas (Mcf)	Boe
	(in thousands)			
Proved Developed and Undeveloped Reserves:				
Beginning of the year	8,519	3,127	20,689	15,094
Extensions and discoveries	4,047	1,369	8,898	6,899
Revisions of previous estimates	(39)	(56)	274	(49)
Purchases of reserves in place	816	294	1,833	1,416
Production	(356)	(2)	(1,480)	(605)
End of the year	12,987	4,732	30,214	22,755
Proved Developed Reserves:				
Beginning of the year	2,070	623	4,230	3,398
End of the year	5,834	1,906	12,186	9,771
Proved Undeveloped Reserves:				
Beginning of the year	6,449	2,504	16,459	11,696
End of the year	7,153	2,826	18,028	12,984

The tables above include changes in estimated quantities of oil and natural gas reserves shown in Bbl equivalents ("Boe") at a rate of six Mcf per one Bbls.

Extensions and discoveries of 33,824 MBoe, 20,132 MBoe and 6,899 MBoe during the years ended December 31, 2014, 2013 and 2012, result primarily from the drilling of new wells during each year and from new proved undeveloped locations added during each year.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2014, 2013, and 2012 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves is as follows:

	December 31, 2014	2013	2012
	(in thousands)		
Future cash inflows	$ 5,423,551	$ 3,446,766	$ 1,405,580
Future development costs	(642,746)	(515,247)	(186,996)
Future production costs	(1,640,422)	(1,097,734)	(368,099)
Future income tax expenses	(903,354)	(24,127)	(9,839)
Future net cash flows	2,237,029	1,809,658	840,646
10% discount to reflect timing of cash flows	(1,281,400)	(1,088,878)	(544,598)
Standardized measure of discounted future net cash flows	$ 955,629	$ 720,780	$ 296,048

(1) Future net cash flows do not include the effects of U.S. federal income taxes on future results because the Company was a limited liability company not subject to entity-level federal income taxation as of December 31, 2013, and 2012. Accordingly, no provision for federal corporate income taxes has been provided because taxable income was passed through to the Company's equity holders. However, the Company's operations located in Texas are subject to an entity-level tax, the Texas

Margin Tax, at a statutory rate of up to 1.0% of income that is apportioned to Texas. Following the Corporate Reorganization, the Company will be a subchapter C corporation subject to U.S. federal and state income taxes. If the Company had been subject to entity-level income taxation, the unaudited pro forma future income tax expense at December 31, 2013 and 2012 would have been $562.5 million and $289.5 million, respectively. The unaudited standardized measure at December 31, 2013, 2012 would have been $497.7 million and $193.6 million, respectively.

In the foregoing determination of future cash inflows, sales prices used for oil, NGLs, and natural gas for December 31, 2014, 2013, and 2012, were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of its' predecessor's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves are as follows:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Standardized measure of discounted future net cash flows at the beginning of the year	$ 720,780	$ 296,048	$ 181,714
Sales of oil and natural gas, net of production costs	(244,745)	(97,365)	(30,621)
Purchase of minerals in place	279,725	227,937	20,222
Divestiture of minerals in place	—	(122)	—
Extensions and discoveries, net of future development costs	537,241	204,135	82,517
Previously estimated development costs incurred during the period	96,881	57,158	36,423
Net changes in prices and production costs	(74,080)	11,463	(21,592)
Changes in estimated future development costs	(9,517)	2,793	1,627
Revisions of previous quantity estimates	(126,395)	(41,242)	(625)
Accretion of discount	73,107	30,010	18,443
Net change in income taxes	(348,501)	(6,240)	(1,336)
Net changes in timing of production and other	51,133	36,205	9,276
Standardized measure of discounted future net cash flows at the end of the year	$ 955,629	$ 720,780	$ 296,048

EXHIBIT INDEX

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of May 29, 2014, by and between Parsley Energy Employee Holdings, LLC and Parsley Energy, Inc. (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
2.2	Purchase and Sale Agreement, dated as of June 4, 2014, by and among OGX Production, LP, OGX Operating, LLC and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.2 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
2.3	Purchase and Sale Agreement, dated as of March 27, 2014, by and between Pacer Energy, Ltd and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.3 to the Company’s Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 14, 2014).
2.4	First Amendment to Purchase and Sale Agreement and Waiver of Conditions Precedent, dated as of May 1, 2014, by and between Pacer Energy, Ltd. and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.4 to the Company’s Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 14, 2014).
2.5	Purchase and Sale Agreement, dated as of August 19, 2014, by and between Cimarex Energy Co. and Parsley Energy, L.P. (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 25, 2014).
3.1	Amended and Restated Certificate of Incorporation of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
3.2	Amended and Restated Bylaws of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
4.1	Indenture, dated as of February 5, 2014, by and among Parsley Energy, LLC, Parsley Finance Corp., each of the guarantors party thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company’s Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
4.2	Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Company’s Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
4.3	Amended and Restated Registration Rights Agreement, dated as of May 29, 2014, by and among Parsley Energy, LLC, Parsley Energy, Inc. and each of the parties listed as Owners on the signature pages thereto (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.1	Amended and Restated Credit Agreement, dated as of October 21, 2013, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Amendment No. 1 to the Company’s Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 5, 2014).
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of December 20, 2013, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.14 to the Company’s Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated as of February 5, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.15 to the Company’s Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).

Exhibit No.	Description
10.4	Fifth Amendment to Amended and Restated Credit Agreement, dated as of May 9, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.19 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.5*	Sixth Amendment to Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto.
10.6	Seventh Amendment to Amended and Restated Credit Agreement, dated as of November 10, 2014, by and among Parsley Energy, L.P., as borrower, and Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 14, 2014).
10.7	Amended and Restated Credit Agreement, dated October 21, 2013, by and among Parsley Energy, L.P., as borrower, Chambers Energy Management, LP, as agent and the several lenders party thereto (incorporated by reference to Exhibit 10.2 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.8†	Employment Agreement, dated as of January 23, 2014, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.9†	Employment Agreement, dated as of January 24, 2014, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.10†	Amended and Restated Employment Agreement, dated as of December 8, 2014, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 9, 2014).
10.11†	Employment Agreement, dated as of February 13, 2014, by and between Parsley Energy Operations, LLC and Matthew Gallagher (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.12†*	Employment Agreement, dated as of December 8, 2014, by and between Parsley Energy Operations, LLC and Thomas Layman.
10.13	Amended and Restated Limited Liability Company Agreement of Parsley Energy Employee Holdings, LLC (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.14	Master Reorganization Agreement, dated as of May 2, 2014, by and among Parsley Energy, Inc., NGP X US Holdings, L.P., Parsley Energy, LLC, the persons identified on the signature page thereto as Existing Members and Parsley Energy Employee Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 28, 2014).
10.15	First Amended and Restated Limited Liability Company Agreement of Parsley Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.16	Tax Receivable Agreement, dated as of May 29, 2014, by and among Parsley Energy, Inc., certain members of Parsley Energy, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.17†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Bryan Sheffield (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).

Exhibit No.	Description
10.18†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Ryan Dalton (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.19†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Michael Hinson (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.20†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Matt Gallagher (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.21†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Paul Treadwell (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.22†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Thomas Layman (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.23†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Colin Roberts (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.24†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Chris Carter (incorporated by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.25†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and David Smith (incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.26†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and A.R. Alameddine (incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.27†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Randy Newcomer (incorporated by reference to Exhibit 10.13 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.28†	Indemnification Agreement, dated as of July 23, 2014, by and between Parsley Energy, Inc. and Hemang Desai (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on July 24, 2014).
10.29†	Indemnification Agreement, dated as of August 19, 2014, by and between Parsley Energy, Inc. and William Browning (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 25, 2014).
10.30†*	Amended and Restated Parsley Energy, Inc. 2014 Long Term Incentive Plan.
10.31†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.32†	Form of Notice of Grant of Restricted Stock (Time-Based) (incorporated by reference to Exhibit 10.17 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.33†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.34†*	Form of Restricted Stock Unit Agreement.

Exhibit No.	Description
10.35†*	Form of Notice of Grant of Restricted Stock Units (Time-Based).
10.36†*	Form of Notice of Grant of Restricted Stock Units (Performance-Based).
10.37	Common Stock Subscription Agreement, dated as of February 5, 2015, by and among Parsley Energy, Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 11, 2015).
10.38	Registration Rights Agreement, dated as of February 11, 2015, by and among Parsley Energy, Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 11, 2015).
21.1*	List of Subsidiaries of Parsley Energy, Inc.
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. Reserve Report.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

† Management contract or compensatory plan or agreement

* Filed herewith. Schedules and similar attachments to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant will furnish a supplemental copy of any omitted schedule or similar attachment to the Commission upon request.

** Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this Annual Report on Form 10-K and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

CORPORATE INFORMATION

MANAGEMENT

BRYAN SHEFFIELD
President, Chief Executive Officer and Chairman of the Board

RYAN DALTON
Vice President, Chief Financial Officer

MATT GALLAGHER
Vice President, Chief Operating Officer

COLIN ROBERTS
Vice President, General Counsel and Secretary

PAUL TREADWELL
Vice President, Operations

MIKE HINSON
Vice President, Land

THOMAS LAYMAN
Vice President, Geoscience

BOARD OF DIRECTORS

BRYAN SHEFFIELD
Chairman of the Board

A.R. ALAMEDDINE[2]
Director

WILLIAM BROWNING[1]
Director

CHRIS CARTER[2][3]
Director

DR. HEMANG DESAI[1][2]
Director

RANDOLPH NEWCOMER, Jr.[1][3]
Director

DAVID SMITH[3]
Director

CORPORATE OFFICES

AUSTIN OFFICE
303 Colorado Street
Suite 3000
Austin, TX 78701
737-704-2300

MIDLAND OFFICE
500 W. Texas Avenue
Suite 200
Midland, TX 79701
432-818-2100

1) Member of the Audit Committee
2) Member of the Compensation Committee
3) Member of the Nominating and Governance Committee

COMMON STOCK
The company's Class A common stock is traded on the New York Stock Exchange under the symbol PE.

INDEPENDENT AUDITOR
KPMG LLP
717 N. Harwood Street, Suite 3100
Dallas, TX 7520

INDEPENDENT PETROLEUM ENGINEERS
Netherland, Sewell & Associates, Inc.
2100 Ross Avenue, Suite 2200
Dallas, TX 75201

INVESTOR AND MEDIA RELATIONS
Shareholders, brokers, securities analysts, portfolio managers or financial news media seeking information about the Company may email us at:
ir@parsleyenergy.com

or call

Brad Smith, CFA
Director, Investor Relations
Parsley Energy, Inc.
512-505-5199

or

Lisa Elliot or Jack Lascar
Dennard-Lascar Associates
713-529-6600

TRANSFER AGENT
For shareholder questions regarding transfer of shares, lost stock certificates, duplicate mailings, change of address or other similar matters, please contact our Transfer Agent:
American Stock Transfer & Trust Company
6201 15th Avenue
Brooklyn, NY 11219
800-937-5449

ANNUAL MEETING
The Annual Meeting of Stockholders will be held Friday, June 19, 2015, at 8:00 a.m. CT
JW Marriott Austin
110 E. 2nd Street
Austin, TX 78701

VISIT OUR WEBSITE
www.parsleyenergy.com

PARSLEY ENERGY

PARSLEYENERGY.COM