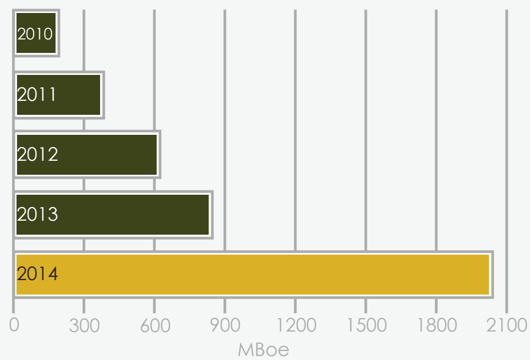
Callon Petroleum

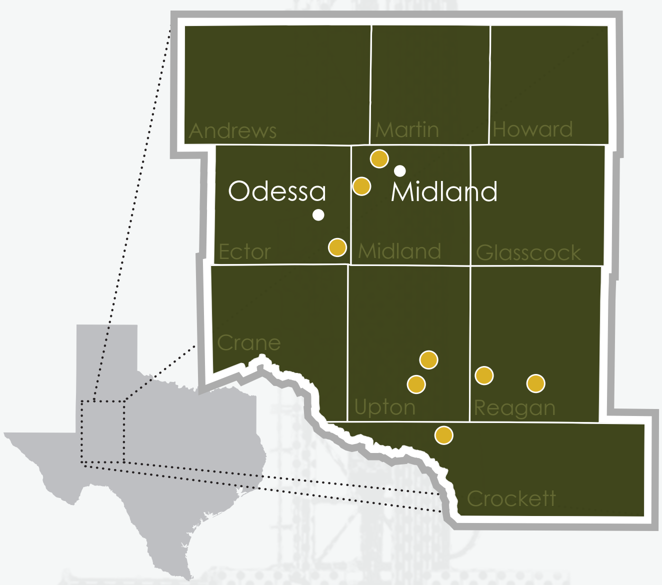
2014 Annual Report

Corporate Profile

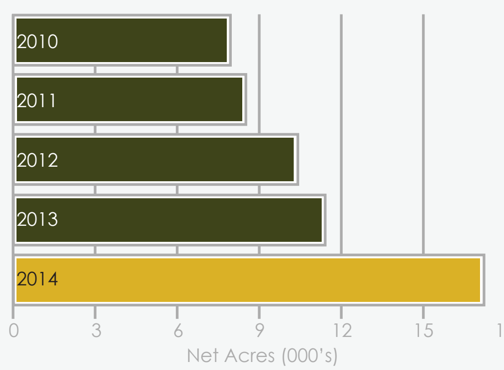
Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950. The Company is focused exclusively in the Permian Basin on building reserves and production through efficient operations and low finding and development costs. The Company's estimated proved reserves at December 31, 2014 were 32.8 million barrels of oil equivalent (MMBoe).

Permian Production

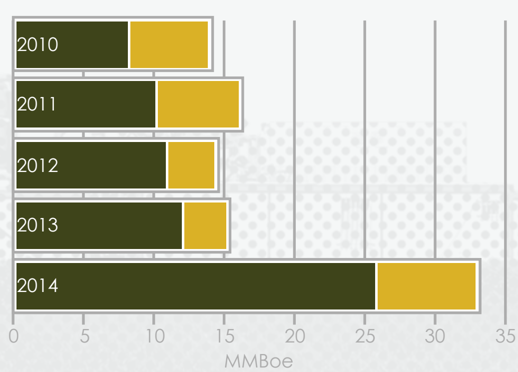




De-Risked Permian Acreage



Proved Reserves By Oil/Gas



To Our Shareholders

With nearly sixty producing horizontal wells from four distinct zones, we have firmly established ourselves as an exceptional, pure-play operator within the oil-rich Midland Basin of the Permian Basin. We enter 2015 with a solid foundation of properties and an associated drilling portfolio concentrated in the heart of the Midland Basin. The dedication and focus of our highly skilled team is evidenced by a year of record proved reserves and production growth. In 2014, we grew our proved reserves by 121% to nearly 33 million barrels of oil equivalent ("MMBOE"). We efficiently invested approximately $218 million of operational capital to generate this 15.7 MMBOE reserve growth, representing an average drill-bit finding and development ("F&D") cost of under $14 per barrel of oil equivalent ("BOE"), a 10% reduction versus last year. Additionally, in 2014 we increased our Permian production by nearly 154% to over 2 MMBOE.

Recognizing the need to continue building upon our foundation for future growth and deliver shareholder value, we added nearly 4,000 net acres in the heart of the Midland Basin to our overall position, which grew our horizontal well inventory by 40% to a level that – assuming our current two-horizontal drilling rig development program – provides approximately 20 years of drilling activity from our four currently producing zones. Adding the other prospective zones across our acreage increases our horizontal drilling inventory to approximately 40 years at our current development pace. These accomplishments, combined with the improvements we've made to our capital structure and continued operational efficiencies, position Callon for long-term operational success and will allow us to deliver meaningful value for our shareholders.

During 2014, we replaced nearly 760% of our production with net proved reserve additions, and we exited 2014 producing at an average rate of nearly 7,300 barrels of oil equivalent per day ("BOE/d") in the fourth quarter, a 144% increase over our corresponding 2013 Permian exit rate of 2,975 BOE/d. Given the current commodity price environment, we decided to return to a focused, two-horizontal rig drilling program and reduce our 2015 capital budget by 25%, as compared to the previous year. Despite the constrained capital plan, we expect to grow total 2015 production, inclusive of production from our recently acquired Cassleman and Bohannon fields (our "CaBo" field area), by over 45% to over 3 MMBOE.

We grew our proved reserves by 121% to nearly 33 million barrels of oil equivalent

Sustained growth in our assets is an important objective, and our pursuit of that goal is governed by a strict focus on capital efficiency and financial discipline. We expect our drilling program to generate average returns of 25% in a $55 flat realized oil price environment, taking into account the well cost reductions we have already achieved to date. Working with our service partners, we have made significant progress reducing our drilling and completion costs, and we will continue in these efforts with the expectation of obtaining additional reductions throughout 2015. The additional cost savings will serve to further reduce our F&D costs and improve our expected returns on capital.

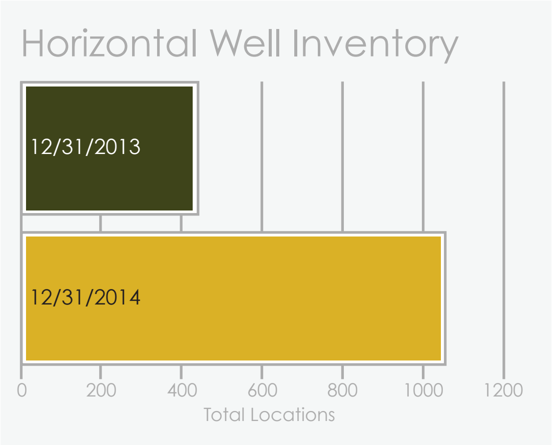
Currently, our total well costs are down 20%, as compared to 2014. Building on the momentum of working with our service partners, we believe that total well costs could decline by as much as 30% from 2014 levels by the second half of 2015. Realizing these incremental reductions would result in well costs of approximately $5.1 million for a 7,500' lateral and $4 million for 5,000' laterals. These lower costs would increase our expected average returns to between 35% and 40% in a flat realized price environment of $55 per BOE. We firmly believe that this pace and magnitude of cost reductions is the product of the strong relationships we have built with our key service partners of the past several years and our willingness to work together through this challenging price environment.

2014 Highlights

- Increased Permian Basin annual production by 154% to 2,062 thousand barrels of oil equivalent ("MBOE")
- Ended 2014 producing nearly 7,300 BOE/d, a 144% increase over 2013
- Increased proved reserves by 121% to nearly 33 MMBOE
- Replaced nearly 760% of 2014 production with additional proved reserves
- Drilled 27 horizontal wells in the Southern & Central Midland Basin, producing from a total of four zones including the Upper and Lower Wolfcamp B, the Wolfcamp A and the Lower Spraberry
- Increased our inventory of horizontal drilling locations by nearly 80% with over 50% targeting currently producing zones
- Increased our drilling inventory to a level supporting 40 years of continuous development based on our current two-horizontal rig drilling program
- Acquired 6,230 gross (3,862 net; 100% held by existing vertical production) surface acres in the core of the Midland Basin located in close proximity to our existing Carpe Diem and Pecan Acres fields, adding 441 horizontal drilling locations including 177 in currently producing zones
- Raised nearly $430 million in equity ($130 million) and long-term debt ($300 million) capital, strengthening our balance sheet, funding our acquisition, and pre-funding a meaningful portion of our ongoing development activity
- Retired the remaining portion of our 13% Senior Notes, further improving our cost of capital
- Grew the borrowing base under our $500 million Senior Secured Credit Facility to $250 million, an increase of more than 200% over the $83 million borrowing base at the end of 2013

A Strong Foundation for Growth

Given the multiple, stacked zone development opportunity across our acreage position in the Permian, we enter 2015 with over 100,000 net effective acres in the Midland Basin that have been de-risked for horizontal development, of which we believe 82% to be located in the oil-rich core of the basin. Our oil production as a percentage of total production, which totaled 82% in 2014, remains well above our peer group average. Similarly, our 2014 proved reserves were comprised of 78% oil, and is expected to increase as we continue to horizontally develop our assets. With only 53 horizontal PUD locations carried at the end of 2014, we continue to employ a conservative booking philosophy. Of these total PUD locations, only three are associated with the Lower Spraberry zone, which we expect to become a larger contributor to our asset profile over time. Having already drilled the single vertical PUD location recorded at the close of 2014, we are now exclusively focused on horizontal development across our acreage.



Importantly, we operate the vast majority of our development and have minimal drilling obligations within our acreage portfolio, which is largely held-by-production. As of January 1, 2015, we estimate that only 10% of our planned 30 gross horizontal wells in 2015 are required to satisfy continuous drilling obligations. We believe this operational status uniquely positions Callon, providing the operational flexibility to accommodate any meaningful changes in the overall commodity price environment that could affect the level of desired drilling activity.

Continue to Increase Producing Zones across our Acreage

We are off to a good start in 2015, poised for efficient program development of the four productive zones where we have already established production to date. During 2014, we added both the Wolfcamp B and Lower Spraberry to production on our Central acreage, expanding upon our Wolfcamp development that was limited to our Southern acreage at the end of 2013. Already in 2015, we've drilled a Lower Spraberry well on our Southern acreage, further de-risking our entire core acreage footprint by producing from the Wolfcamp A, Wolfcamp B (Upper and Lower) and Lower Spraberry.

While we remain focused on the Wolfcamp B, the longer term performance of our initial Lower Spraberry wells is very encouraging, and will likely attract additional capital allocation over time. Our first two horizontal wells targeting the Lower Spraberry, which are located in northwest Midland County within our Carpe Diem and Casselman fields, produced an average of over 192 BOE/d per 1,000' completed lateral feet. Importantly, the 751 BOE/d 30-day peak rate observed at the Casselman field was materially above the 315 BOE/d 30-day peak rate associated with the Lower Spraberry type curve used for evaluation and planning purposes at the time of the acquisition, assuming equivalent completed laterals.

We continue to monitor offsetting peer operator activity and our technical evaluation around other zones we believe are likely to become productive in the future, including the Jo-Mill, Wolfcamp C and Cline formations. In total, our horizontal inventory consists of nearly 1,050 potential locations with approximately 40 years of drilling inventory for a two-rig drilling program on our existing acreage, a 151% increase over our drilling inventory at the end of 2013.

Focus on Operational Efficiency

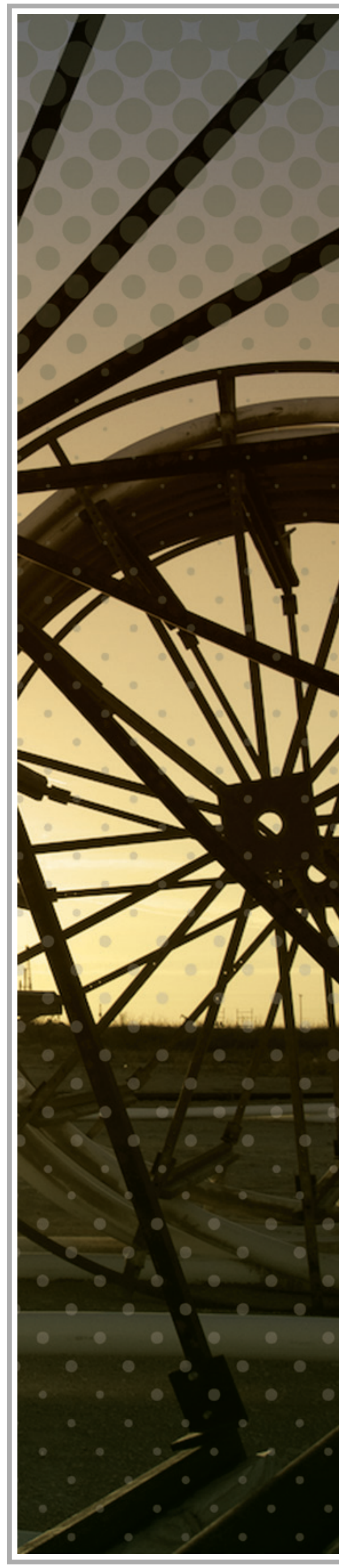
We continue to implement an increasing portion of gas lift systems for wells targeting the Wolfcamp zones as we believe that this form of artificial lift, combined with the practice of restricting total produced fluids (oil and water), will contribute to shallower production declines and reduce the impact of interference from offsetting well completions. Additionally, we believe other economic benefits will stem from these practices including the deferral of a portion of production volumes into a contango oil price environment and a reduction in water-handling infrastructure investments.

Following our fourth quarter close of the CaBo acquisitions, we dedicated a great deal of focus during the last part of 2014 to the integration of these fields into our ongoing operations. The transition has gone well as we make progress developing good relationships with our working interest partners. We continue to have constructive conversations with offset operators, and have secured off-lease surface locations for our planned wells in 2015, which effectively allow us to access an incremental 10% of completed lateral length. This progress, combined with the encouraging initial well results in both the Wolfcamp B and Lower Spraberry, affirms our excitement about the potential for this core area and growth platform.

Production continues to benefit from improved chemical treatments and raising rod pumps in vertical wells. During the fourth quarter, with the decline in commodity prices, we instituted a more stringent framework for performing workovers of mature vertical wells. The result is a reduced number of expected workovers, combined with lower associated workover service costs, is a key driver of our expectation for lower lease operating costs in 2015.

Solid Balance Sheet and Improved Liquidity

We remain focused on generating both organic and acquired growth, recognizing the need for cost-effective capital and financial flexibility. Our recent long-term capital raise of nearly $500 million, including approximately $68 million from our equity offering in March of 2015, significantly enhances Callon's preparedness to enter a more challenging commodity price environment this year. We have no debt maturities until 2019, allowing us to invest our cash flows from operations into the continued development of our high-quality asset base. As we meaningfully grow production, we benefit from the ability to spread our fixed costs over a larger production base, and our focus on cost control allows us to maintain strong cash margins. Falling well costs reduces our capital funding needs, and our current hedge portfolio provides significantly stronger cash flow relative to current commodity pricing.



As of December 31, 2014, our unsettled hedges were valued at $27.8 million and include oil hedges with an average swap price of nearly $71per barrel on an average of over 4,150 barrels of oil per day in 2015.

Our $250 million borrowing base under our credit facility was less than 15% drawn at the end of 2014, and will be repaid with proceeds from our most recent equity offering. The fully-available borrowing base provides low-cost liquidity to fund our two-rig horizontal drilling capital program well beyond 2015, assuming current commodity prices and service costs.

2015 Outlook

We enter 2015 well-positioned for continued success. Our focus on established zones in our core fields translates into an operational plan that requires minimal high-grading of acreage relative to previous activity. Despite the significant pullback in commodity prices over the past several months, our quality asset base, fiscal discipline, recent long-term capital raises and a strong 2015 hedge portfolio collectively position us to continue adding meaningful value to our shareholders. While the $163 million midpoint of our 2015 operational capital budget reflects a 25% reduction of our operational capital deployed in 2014, we still expect to exit 2015 producing at a rate 15% over our 2014 exit rate. To achieve this increase, we expect to place onto production approximately 30 gross (24 net) wells targeting each of our four currently productive zones – the Lower Spraberry, Wolfcamp A, and the Upper and Lower Wolfcamp B. Inclusive of the production contributed by our recently acquired CaBo fields, we project total 2015 production to grow 45% over last year. Reflective of our reduced capital program, we have already secured a 40% reduction in drilling rig costs and average cost reductions of over 20% for completion and ancillary services. With well costs that are already 20% below last year's levels, the current environment provides the opportunity to improve upon our 2014 "drill-bit" F&D costs of $13.91 per barrel of oil equivalent. Another advantage we enjoy is the operational flexibility we possess because we operate nearly 100% of our leasehold that is largely held-by-production. Accordingly, we have the flexibility to adjust our capital program to accommodate unexpected changes in the macroeconomic environment. We believe our focused, two-rig horizontal drilling program led by an exceptional operating team will continue to add value to our shareholders, and position Callon to capitalize on further potential decreases in development costs while maintaining operational momentum for the future.

Gratitude

Establishing ourselves as a exceptional operator within the Midland Basin has only been possible because of the Callon team's talent and dedication. With nearly 65 years in the business, I am extremely proud of what the team has built in the five short years we have been operating in the Basin, especially the creation of a culture focused on safety and responsible development. Although we as an industry face challenges in the current commodity price environment, I firmly believe that our high-quality asset base and continued progress to improve capital efficiency will continue to generate long-term value for our shareholders.

I also want to express my appreciation for our Board of Directors who remain fully committed to creating value for all Callon shareholders. Their vision, expertise and persistence have been invaluable as we have solidified Callon as a pure-Permian operator. We are fortunate to have a Board with the quality and diversity of experience its members possess, and I look forward to working with the Board as we continue to work towards the ongoing successful execution of our horizontal development and growth strategy.

Fred L. Callon
Chairman, President and Chief Executive Officer
March 27, 2015

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

FORM 10-K

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

For The Fiscal Year Ended December 31, 2014

OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________ to ____________
Commission File Number 001-14039

Callon Petroleum Company
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**64-0844345**
(State or Other Jurisdiction of ncorporation or Organization)	(IRS Employer Identification No.)
200 North Canal Street **Natchez, Mississippi**	**39120**
(Address of Principal Executive Offices)	(Zip Code)

601-442-1601
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $.01 par value	New York Stock Exchange
10.0% Series A Cumulative Preferred Stock	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants 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 definition of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if 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 the registrant as of June 30, 2014 was approximately $456.3 million. The Registrant had 55,510,729 shares of common stock outstanding as of February 27, 2015**.**

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2014) relating to the Annual Meeting of Stockholders to be held on May 14, 2015, which are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward Looking Statements

All statements, other than statements of historical fact, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve quantities, present value and growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-K identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for oil, natural gas and NGLs (including regional basis differentials),
- our ability to transport our production to the most favorable markets or at all,
- the timing and extent of our success in discovering, developing, producing and estimating reserves,
- our ability to fund our planned capital investments,
- the impact of government regulation, including regulation of endangered species, any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives,
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services,
- our future property acquisition or divestiture activities,
- the effects of weather,
- increased competition,
- the financial impact of accounting regulations and critical accounting policies,
- the comparative cost of alternative fuels,
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed,
- credit risk relating to the risk of loss as a result of non-performance by our counterparties, and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that the forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or in our 2014 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their prescribed meanings when used in this report. As used in this document:

- **ARO**: asset retirement obligation.
- **Bbl** or **Bbls**: barrel or barrels of oil or natural gas liquids.
- **Bcf**: Billion cubic feet of natural gas.
- **BOE**: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- **BBtu**: billion Btu.
- **BOE/d**: BOE per day.
- **BLM:** Bureau of Land Management.
- **Btu**: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **DOI:** Department of Interior.
- **EPA:** Environmental Protection Agency.
- **FASB:** Financial Accounting Standards Board.
- **GAAP:** Generally Accepted Accounting Principles in the United States.
- **GHG:** greenhouse gases.
- **LIBOR**: London Interbank Offered Rate.
- **LOE:** lease operating expense, including workover expense.
- **MBbls**: thousand barrels of oil.
- **MBOE**: thousand BOE.
- **MBOE/d**: Mboe per day.
- **Mcf**: thousand cubic feet of natural gas.
- **MMBbls**: million barrels of oil.
- **MMBOE**: million BOE.
- **MMBtu**: million Btu.
- **MMcf**: million cubic feet of natural gas.
- **MMcf/d**: MMcf per day.
- **NGL or NGLs**: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- **NYMEX**: New York Mercantile Exchange.
- **Oil**: includes crude oil and condensate.\
- **PDPs**: proved developed producing reserves.
- **PDNPs**: proved developed non-producing reserves.
- **PUDs**: proved undeveloped reserves.
- **RSU**: restricted stock units.
- **SEC**: United States Securities and Exchange Commission.

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.
Items 1 and 2 – Business and Properties

Overview

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950.

In 2013, we completed our onshore strategic repositioning that began in 2009, shifting our operations from the offshore waters in the Gulf of Mexico to the onshore Permian Basin in West Texas. Our asset base is concentrated exclusively in the Midland Basin, a sub-basin located within the broader Permian Basin, characterized by high drilling success rates, high oil content, multiple vertical and horizontal productive intervals, and extensive production history. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Our net daily production for calendar year 2014 was 5,648 BOE/d (approximately 82% oil), representing an approximately 155% increase over comparable net daily Permian production in 2013. The increase is primarily attributed to our increased focus on horizontal development initiated in 2012. We currently operate two horizontal drilling rigs focused on four prospective zones for development.

As of December 31, 2014, we had estimated net proved reserves of 25.7 MMBbls and 42.5 Bcf, or 32.8 MMBOE, all of which were located in the Midland Basin. Additionally, 78% of our proved reserves were crude oil and 55% were proved developed at year-end 2014 on a BOE basis.

Our Business Strategy

Our goal is to enhance stockholder value through the execution of the following strategy:

Drive production and maximize resource recovery and reserve growth through horizontal development of our resource base. We believe our horizontal development efforts provide improved returns relative to vertical development of our resource base. Our initial vertical development programs allowed us to amass a database related to the subsurface geology and rock characteristics over the last several years. This information, combined with our review of industry activity and best practices, provided the foundation for us to initiate the horizontal development of our resource base in 2012 and further increase horizontal activity in recent quarters. As of December 31, 2014, we had 49 gross producing horizontal wells, all of which we operate. During the fourth quarter of 2014, approximately 70% of our total Permian production was sourced from horizontal wells. We expect to grow the contribution of horizontal production volumes, both from our existing properties and from properties acquired in recent acquisitions, as we continue to execute a resource development program almost exclusively focused on horizontal development.

Expand our drilling portfolio through evaluation of existing acreage. Our horizontal development drilling efforts to date have been primarily focused on the Upper and Lower Wolfcamp B zones. We have focused on these development zones to reduce drilling risk as we continue to grow our asset base in the Permian Basin, though we have continued to expand our development focus on a measured basis. Most recently, we drilled three Lower Spraberry wells in the Southern and Central Midland Basin in the second half of 2014, complementing three Wolfcamp A wells placed on production in the Southern Midland Basin since the third quarter of 2013. We believe incremental opportunities exist to selectively target other prospective zones across various positions of our acreage, including the Clearfork, Jo Mill, Middle Spraberry, Wolfcamp C and Cline formations (in order of relative depth). In addition, we will continue to monitor the efficiency of our horizontal wells related to reservoir drainage over time, and will pursue downspacing initiatives within target zones if we believe overall returns would be enhanced.

Pursue selective acquisitions in the Permian Basin. During 2014, we continued to demonstrate our ability to acquire and trade acreage in the Midland Basin. Most significantly, we acquired 6,230 gross (3,862 net) acres located in Midland and Andrews Counties, which are in close proximity to our existing Carpe Diem and Pecan Acres fields, for approximately $210 million. Due to its close proximity to our existing fields, we believe this acquired acreage can be efficiently integrated into our ongoing horizontal development activity. The acquisition added 194 gross (121.6 net) potential horizontal drilling locations targeting the currently producing Wolcamp B, Lower Spraberry and Middle Spraberry zones, and additional potential horizontal drilling locations targeting four other prospective zones that are producing in offsetting fields. We also expanded our asset base in existing core development fields by acquiring 1,527 net acres for approximately $8.2 million through a "bolt-on" strategy whereby we identify and pursue smaller blocks of offsetting acreage that are potentially inefficient for the current owner to develop, but have value to Callon based on its location relative to our acreage. These smaller scale acquisitions generally provide acreage at costs significantly below the value assigned to larger blocks of acreage. While remaining mindful about our liquidity, we will continue to pursue leasehold acquisitions in the Permian Basin, and primarily in the Midland Basin, that have horizontal resource potential that can be further augmented by "bolt-on acreage" acquisitions and acreage trades over time.

Maintain financial liquidity and capacity to capitalize on growth opportunities. We believe that our asset base provides the opportunity to deploy a significant amount of capital for horizontal development in the coming years. We have focused on positioning ourselves to supplement our cash flow from operations with an improved cost of debt capital. In conjunction with our acquisition completed in the fourth quarter of 2014, we raised approximately $430 million in gross proceeds through a combination of common equity and long-term debt securities to support the acquisition and our ongoing development efforts in the Midland Basin.

Our Strengths

Established resource base and acreage position in the Permian Basin. Our production is exclusively from the Permian Basin in West Texas, an area that has supported production since the 1940s. The basin has well-established infrastructure from historical operations, and we believe the Basin also benefits from a relatively stable regulatory environment that has been established over time. We have assembled a position of approximately 18,065 net surface acres in the Southern and Central Midland Basin that are prospective for multiple oil-bearing intervals that have been produced by us and other industry participants. As of December 31, 2014, our estimated net proved reserves were comprised of approximately 78% oil and 22% natural gas, which includes NGLs in the production stream.

Multi-year drilling inventory. Our current acreage position in the Permian Basin provides visible growth potential from a horizontal drilling inventory of approximately 525 locations, or 20 years under our current two-rig horizontal drilling program, based solely on four currently producing zones, which include the Lower Spraberry, the Wolfcamp A and the Upper and Lower Wolfcamp B. This drilling inventory increases to over 1,000 drilling locations, with the addition of drilling locations from other prospective zones, which include the Clearfork, Middle Spraberry, Jo Mill, Wolfcamp C and the Cline (or Wolfcamp D). Our identified well locations across our Southern and Central Midland Basin acreage are based upon the results of horizontal wells drilled by us and other offsetting operators, and our analysis of core data and historical vertical well performance.

Experienced team operating in the Permian Basin. We have assembled a management team experienced in acquisitions, exploration, development and production in the Midland Basin. Reflective of this experience, we have realized improvements in our drilling and capital efficiency since launching our horizontal drilling program in 2012 and drilling more than 50 horizontal wells with lengths varying from approximately 5,000 feet to 10,000 feet. We continue to evaluate our completion techniques, and downspacing initiatives that we believe have the potential to improve resource recovery and contribute to enhanced returns on capital. In addition, we regularly evaluate our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

High degree of operational control. We operate nearly all of our Permian Basin acreage and have limited continuous drilling requirements across our acreage. For example, only 10% of our planned development drilling activity in 2015 is required to satisfy acreage commitments, with decreasing obligations in future years. This acreage status, combined with our control as an operator across the majority of our properties, provides us the opportunity to modify our operational plans to respond to changes in operational and commodity price environments. In addition, we have the ability to change our drilling schedule as needed to manage the assimilation of newly acquired acreage that may have drilling commitments.

Operating culture focused on safety and the environment. We have a Health, Safety and Environmental ("HSE") department dedicated to our operations in the Permian Basin. This group is responsible for developing and implementing work processes to mitigate safety and environmental risks associated with our work activities. With emphasis on planning, training and communication, and empowering both our employees and third party service providers with Stop Work Authority, we continue to improve operational performance. Callon has enhanced Management of Change, routine inspections and compliance action tracking methods with the implementation of a HSE management system software program. This department also coordinates closely with our operational team to ensure effective communication with appropriate regulatory bodies as well as landowners. We believe that our proactive efforts in this area have made a positive impact on our operations and culture.

Exploration and Development Activities

Our 2014 total capital expenditures, including acquisitions, were $455.5 million, representing a 166% increase over 2013 capital expenditures. Of the $455.5 million, $217.7 million was allocated to drilling, development and leasehold acquisition activity in the Permian Basin. During 2014, we drilled 27 gross (24.4 net) horizontal and 7 gross (4.3 net) vertical wells, while completing 31 gross (27.3 net) horizontal and 5 gross (3.1 net) vertical wells. Capital expenditures for 2014 included the following expenditures (in millions):

Southern Midland Basin	$	160.3
Central Midland Basin		56.9
Northern Midland Basin		0.5
Total operational expenditures		217.7
Capitalized general and administrative costs allocated directly to exploration and development projects		12.5
Capitalized interest		2.4
Total capitalized general and administrative and interest costs		14.9
Total operational expenditures inclusive of capitalized general and administrative and interest costs		232.6
Acquisitions		222.9
Total capital expenditures	$	455.5

In late 2014, we expanded our horizontal pad development efforts to six fields. We expect our 2015 horizontal drilling program will be primarily focused on development of established Upper and Lower Wolfcamp zones in the Southern and Central Midland Basin. We also expect to drill five wells in the Southern and Central Midland Basin targeting the Lower Spraberry shale formation and one well targeting the Wolfcamp A shale formation.

Recent Developments

We are currently operating two horizontal drilling rigs, complemented by an additional vertical rig that is being used to drill the vertical section of horizontal wells. Based on current commodity market conditions, the Company has elected to release the vertical rig in mid-March and focus on a two-rig horizontal program for the balance of 2015.

Oil and Natural Gas Properties

As of December 31, 2014, our estimated net proved reserves totaled 32.8 MMBOE and included 25.7 MMBbls of oil and 42.5 Bcf, of natural gas with a pre-tax present value, discounted at 10%, of $629.7 million. Pre-tax present value is a non-GAAP financial measure, which we reconcile to the GAAP measure of standardized measure of $579.5 million in note (d) to the table below. Oil constituted approximately 78% of our total estimated equivalent net proved reserves and approximately 77% of our total estimated equivalent proved developed reserves.

The following table sets forth certain information about our estimated net proved reserves prepared by our independent petroleum reserve engineers by major area and for all other properties combined at December 31, 2014:

	Estimated Net Proved Reserves				Pre-tax Discounted Present
	Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MBoe)**		**Value ($000)**
			(a)		(b)(c)(d)
Southern Midland Basin	16,973	26,102	21,323	$	416,463
Central Midland Basin	8,736	16,337	11,459		219,286
Northern Midland Basin	24	109	42		803
Other	—	—	—		(6,872)
Total	25,733	42,548	32,824	$	629,680

(a) We convert Mcf to BOE using a conversion ratio of six Mcf to one Bbl. This ratio, which is typical in the industry and represents the approximate energy equivalent of a Mcf to a Bbl, does not reflect to market price equivalence of Mcf of natural gas compared with a Bbl of oil or NGLs. On a market price equivalence basis, a barrel of oil or NGLs has a substantially higher price than six Mcf of natural gas.

(b) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2014, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, DeGolyer and MacNaughton.

(c) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2014, in accordance with accounting for asset retirement obligations rules. These obligations were retained following the sale of our offshore operations. The negative Pre-Tax Discounted Present Value of the "Other" reflects plugging and abandonment obligations exceeding the future net cash flows.

(d) The Company uses the financial measure "Pre Tax Discounted Present Value" which is a non-GAAP financial measure. The Company believes that Pre Tax Discounted Present Value, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2014 was $579.5 million inclusive of the $50.1 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $6.38 used in the 2014 reserve estimates has been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected per barrel oil price of $86.30 used in the 2014 reserve estimates has been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

Permian Basin

As of December 31, 2014, we owned leaseholds in 27,366 net acres in the Permian Basin. Average net production from the Company's Permian Basin properties increased 155% to 5,648 BOE/d in 2014 from 2,227 BOE/d in 2013.

Southern Midland Basin

- Counties (fields)
  - Upton (East Bloxom and Opal)
  - Reagan (Taylor Draw and Garrison Draw)
  - Crockett (Block 5)
- 10,790 net acres as of December 31, 2014
- 59 gross (54 net) vertical and 39 gross (36 net) horizontal producing wells as of December 31, 2014
- Initiated horizontal development in 2012
- 4th quarter 2014 net production: 4,519 BOE/d (90% horizontal)

The Southern Midland Basin is our largest operating area in terms of production. We currently have 10,790 net acres in this area. We commenced horizontal drilling efforts at our East Bloxom field in 2012 and have expanded our efforts to two additional fields in the Southern Midland Basin using pad development. Our horizontal wells are currently producing from three zones of the Wolfcamp shale (Upper Wolfcamp B, Lower Wolfcamp B and Wolfcamp A). We plan to continue focusing on these intervals in 2015 and also place our first Lower Spraberry well on production in the first quarter of 2015.

Central Midland Basin

- Counties (fields)
  - Midland (Carpe Diem, Pecan Acres, Casselman and Bohannon)
  - Ector (Kayleigh and Bohannon)
  - Andrews (Bohannon)
  - Martin (Casselman)
- 7,275 net acres as of December 31, 2014

- 218 gross (144 net) vertical and 11 gross (8 net) horizontal producing wells as of December 31, 2014
- Initiated horizontal development in 2013
- 4th quarter 2014 net production: 2,736 BOE/d

The Central Midland Basin has historically been the focus of our high-graded vertical drilling program, targeting multiple zones down to the Woodford shale. We shifted our focus to horizontal development in this area with our initial Wolfcamp B wells placed on production in the first quarter of 2014 in our Carpe Diem field. We have continued with program development of both the Wolfcamp B and Lower Spraberry zones in this field over the course of the year and are currently expanding our horizontal development to the Pecan Acres field. Importantly, we recently completed our last vertical well in the area and have no plans or obligations to drill any future vertical wells within our Permian Basin property base.

In addition to this organic drilling activity, in October 2014 we acquired 6,230 gross (3,862 net) acres located in Midland, Andrews and Martin Counties, which are in close proximity to our existing Carpe Diem and Pecan Acres fields. Since the closing of the acquisition, we have placed two Wolfcamp B and one Lower Spraberry wells on production.

Northern Midland Basin

We acquired 21,617 net acres in Borden and Lynn Counties in 2012. We currently own 9,301 net acres following our decision to allow acreage in the Northern Midland Basin to expire as we refined our targeted areas for exploration. At this time, we have no plans for future activity and anticipate that our Northern Midland Basin acreage will expire in its entirety by 2016. As such, we reclassed approximately $25 million of the carrying value of our Northern Midland acreage that were classified as unevaluated properties to evaluated properties. We have no PUDs attributable to this acreage. At December 31, 2014, we had one gross (one net) producing vertical well in this area.

For additional details regarding our Permian wells and related information, please see "Present Activities and Productive Wells" included below within this Item.

Other Property

We own a leasehold in 37,326 net acres located in various counties in Nevada. These leases are with the Bureau of Land Management and carry primary terms that expire in 2018 and 2019. We are evaluating this acreage in conjunction with a third-party consultant and developing options for future activity. Callon does not have any drilling commitments related to this acreage during the primary term. However, we reclassed approximately $3 million of the carrying value of our Nevada acreage that were classified as unevaluated properties to evaluated properties. We have no PUDs or drilling commitments attributable to this acreage. We own additional immaterial properties in Louisiana.

Proved Reserves

Estimates of volumes of proved reserves at year-end, net to our interest, are presented in MBbls for oil and in MMcf for natural gas, including NGLs, at a pressure base of 15.025 pounds per square inch. Total equivalent volumes are presented in BOE. For the BOE computation, 6,000 cubic feet of gas are the equivalent of one barrel of oil. The ratio of six Mcf of gas to one BOE is typically used in the oil and gas business and represents the approximate energy equivalent of a barrel of oil and a Mcf of natural gas. The price of a barrel of oil is much higher than the price of six Mcf of natural gas, so the ratio of six Mcf to one BOE does not reflect the economic equivalent of a barrel of oil to six Mcf of gas.

The following table sets forth certain information about our estimated net proved reserves. All of our proved reserves are currently located in the continental United States and also included volumes in federal and state waters in the Gulf of Mexico at year-end 2012.

	For the Year Ended December 31,		
	2014 (a)	2013 (a)	2012 (a)
Proved developed			
Oil (MBbls)	14,006	5,960	4,955
Natural gas (MMcf)	25,171	9,059	10,680
MBOE	18,201	7,470	6,735
Proved undeveloped			
Oil (MBbls)	11,727	5,938	5,825
Natural gas (MMcf)	17,377	8,692	9,073
MBOE	14,623	7,387	7,337
Total proved			
Oil (MBbls)	25,733	11,898	10,780
Natural gas (MMcf)	42,548	17,751	19,753
MBOE	32,824	14,857	14,072
Financial Information			
Estimated pre-tax future net cash flows (b)	$ 1,330,628	$ 680,627	$ 592,424
Pre-tax discounted present value (b) (c)	$ 629,680	$ 301,144	$ 250,097
Standardized measure of discounted future net cash flows (b) (c)	$ 579,542	$ 283,946	$ 231,148

(a) The Company's estimated proved reserves as of December 31, 2014 were prepared by DeGolyer and MacNaughton and estimated proved reserves as of December 31, 2013 and 2012 were prepared by Huddleston & Co.

(b) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2014 and 2013, in accordance with accounting for asset retirement obligations rules.

(c) The Company uses the financial measure "pre-tax discounted present value" which is a non-GAAP financial measure. The Company believes that pre-tax discounted present value, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2014 was $579.5 million inclusive of the $50.1 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $6.38 used in the 2014 reserve estimates has been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected per barrel oil price of $86.30 used in the 2014 reserve estimates has been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

See Note 13 of our Consolidated Financial Statements for the additional information regarding the Company's reserves including its estimates of proved reserves, PDPs, PUDs and the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves.

The Company's estimated net proved reserves increased 121% to 32.8 MBOE from 14.9 MBOE at December 31, 2014 and 2013, respectively. Additions during the year were due to (1) 15.7 MMBOE related to the Company's horizontal development of a portion of its Permian Basin properties and (2) 4.7 MMBOE related to acquired properties in the Permian Basin. These increases were partially offset by (1) 2.1 MMBOE related to the Company's production during 2014 and (2) 0.3 MMBOE of net revisions, including 0.8 MMBOE of positive performance-related revisions that were offset by 1.1 MMBOE of PUD reclassifications.

Proved Undeveloped Reserves (PUDs)

Annually, the Company reviews its PUDs to ensure appropriate plans exist for development. PUD reserves are recorded only if the Company has plans to convert these reserves into PDPs within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2015 capital budget and, in subsequent years, the allocation of capital within our long-range business plan to convert PUDs to PDPs within this five year period. In general, our 2015 capital budget and our long-range capital plans are primarily governed by our expectations of internally generated cash flow and credit facility borrowing availability. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in commodity pricing, oilfield service costs and availability, and other economic factors may lead to changes in development plans.

The following table summarizes the Company’s recorded PUDs (in MBOE):

	For the Year Ended December 31,		
	2014	2013	2012
Permian Basin	14,623	7,387	6,040
Medusa (a)	—	—	1,297
Total	14,623	7,387	7,337

(a) Effective July 1, 2013, we sold our interest in the Medusa field. See Note 3 for additional information.

Our PUDs increased 98% to 14.6 MMBOE from 7.4 MMBOE at December 31, 2014 and 2013, respectively. We added 10.1 MMBOE to our PUDs, net of revisions, primarily from the continued horizontal development of our Permian Basin properties. The increase in PUDs was partially offset by the reclassification of 1.8 MMBOE, or 24%, included in the year-end 2013 PUD reserves, to PDPs as a result of our horizontal development of Permian Basin properties at a total cost of approximately $34.6 million, net. Also offsetting the increase was the removal of 1.1 MMBOE of PUDs, including the impact from the reclassification of previous vertical PUDs to the horizontal probable category given our focus on horizontal development.

The Company plans to develop its PUDs as part of a multi-year drilling program. At December 31, 2014, we had no reserves that remained undeveloped for five or more years, and all PUD drilling locations are currently scheduled to be drilled within three to five years of their initial recording.

Controls Over Reserve Estimates

Compliance as it relates to reporting the Company’s reserves is the responsibility of our Senior Vice President of Operations, who has over 35 years of industry experience including 27 years as a manager and is our principal engineer. In addition to his years of experience, our principal engineer holds a degree in petroleum engineering and is experienced in asset evaluation and management.

Callon’s controls over reserve estimates included retaining DeGolyer and MacNaughton, a Texas registered engineering firm, as our independent petroleum and geological firm. The Company provided to DeGolyer and MacNaughton information about our oil and gas properties, including production profiles, prices and costs, and DeGolyer and MacNaughton prepared its own estimates of the reserves attributable to the Company’s properties. All of the information regarding 2014 reserves in this annual report is derived from DeGolyer and MacNaughton’s report. DeGolyer and MacNaughton’s reserve report letter is included as an Exhibit to this annual report. The principal engineer at DeGolyer and MacNaughton who certified the Company’s reserve estimates has over 40 years of experience in the oil and gas industry and is a Texas Licensed Professional Engineer. Further professional qualifications include a degree in petroleum engineering and membership in the International Society of Petroleum Engineers and the American Association of Petroleum Geologists.

All of the information regarding 2013 and 2012 reserves in this annual report is derived from reserve reports prepared by Huddleston & Co., Inc., a Texas engineering firm.

To further enhance the control environment over the reserve estimation process, our Strategic Planning Committee, a committee of the Board of Directors, assists management and the Board with its oversight of the integrity of the determination of the Company’s oil and natural gas reserves and the work of our independent reserve engineer. The Committee’s charter also specifies that the Committee shall perform, in consultation with the Company’s management and senior reserves and reservoir engineering personnel, the following responsibilities:

Oversee the appointment, qualification, independence, compensation and retention of the independent petroleum and geological firm (the “Firm”) engaged by the Company (including resolution of material disagreements between management and the Firm regarding reserve determination) for the purpose of preparing or issuing an annual reserve report. The Committee shall review any proposed changes in the appointment of the Firm, determine the reasons for such proposal, and whether there have been any disputes between the Firm and management.

Review the Company’s significant reserves engineering principles and policies and any material changes thereto, and any proposed changes in reserves engineering standards and principles which have, or may have, a material impact on the Company’s reserves disclosure.

Review with management and the Firm the proved reserves of the Company, and, if appropriate, the probable reserves, possible reserves and the total reserves of the Company, including: (i) reviewing significant changes from prior period reports; (ii) reviewing key assumptions used or relied upon by the Firm; (iii) evaluating the quality of the reserve estimates prepared by both the Firm and the Company relative to the Company’s peers in the industry; and (iv) reviewing any material reserves adjustments and significant differences between the Company’s and Firm’s estimates.

If the Committee deems it necessary, it shall meet in executive session with management and the Firm to discuss the oil and gas reserve determination process and related public disclosures, and any other matters of concern in respect of the evaluation of the reserves.

During our last fiscal year, we filed no reports with other federal agencies which contain an estimate of total proved net oil and natural gas reserves.

Production Volumes, Average Sales Prices and Operating Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, the Company’s sale of oil and natural gas for the periods indicated (dollars in thousands, except per unit data).

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Production			
Oil (MBbl)	1,692	911	977
Natural gas (MMcf)	2,220	3,011	3,588
Total (MBoe)	2,062	1,413	1,575
Revenues			
Oil sales	$ 139,374	$ 88,960	$ 96,584
Natural gas sales	12,488	13,609	14,149
Total	$ 151,862	$ 102,569	$ 110,733
Operating costs			
Lease operating expense	$ 22,372	$ 19,779	$ 23,330
Production taxes	8,973	4,133	3,224
Total	$ 31,345	$ 23,912	$ 26,554
Average realized sales price			
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 82.37	$ 97.65	$ 97.41
Oil (Bbl) (including impact of cash settled derivatives)	84.85	99.32	98.86
Natural gas (Mcf) (excluding impact of cash settled derivatives)	5.63	4.52	3.94
Natural gas (Mcf) (including impact of cash settled derivatives)	5.59	4.47	3.94
Total (BOE) (excluding impact of cash settled derivatives)	73.65	72.59	69.43
Total (BOE) (including impact of cash settled derivatives)	75.64	73.56	70.41
Operating costs per BOE			
Lease operating expense	$ 10.85	$ 14.00	$ 14.81
Production taxes	4.35	2.92	2.05
Total	$ 15.20	$ 16.92	$ 16.86

Present Activities and Productive Wells

The following table sets forth the wells drilled and completed during the periods indicated. All such wells were drilled in the continental United States.

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	22	20.1	22	20.1	3	3.0
Total	23	21.1	23	21.1	3	3.0
Central Midland Basin						
Vertical wells	4	1.8	3	1.3	1	0.4
Horizontal wells	5	4.3	9	7.2	—	—
Total	9	6.1	12	8.5	1	0.4
Northern Midland Basin						
Vertical wells	2	1.5	1	0.8	—	—
Total	2	1.5	1	0.8	—	—
Total vertical wells	7	4.3	5	3.1	1	0.4
Total horizontal wells	27	24.4	31	27.3	3	3.0
Total	34	28.7	36	30.4	4	3.4

(a) Completions include wells drilled prior to 2014.

The following table sets forth the Company’s drilled and completed wells, none of which were natural gas or nonproductive for the periods reflected:

	2014 (a)		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Oil wells						
Development	19	15.5	19	17.2	14	9.7
Exploratory	13	11.7	7	5.0	7	6.2
Total	32	27.2	26	22.2	21	15.9

(a) Does not include two gross (two net) non-producing exploratory wells.

The following table sets forth productive wells as of December 31, 2014:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	328	243.0	—	—
Royalty interest	3	0.1	—	—
Total	331	243.1	—	—

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a BOE basis. However, most of our wells produce both oil and natural gas.

For the periods presented, the following table sets forth by major field(s) net production volumes and percentage of estimated proved reserves:

	For the Year Ended December 31,					
	Production Volumes (MBOE)			% of Total Proved Reserves		
	2014	2013	2012	2014	2013	2012
Permian Basin:						
Southern Midland Basin	1,497	612	402	65%	85%	51%
Central Midland Basin	549	193	189	35%	14%	16%
Northern Midland Basin	16	8	—	0%	1%	0%
Total	2,062	813	591	100%	100%	67%
Offshore and other (a)	—	600	984	0%	0%	33%
Total	2,062	1,413	1,575	100%	100%	100%

(a) In late 2013, we sold the remaining interests in our producing offshore fields and in the Haynesville shale.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2014.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	936	200	188	55	1,124	255
Texas (a)	20,991	16,487	12,498	10,879	33,489	27,366
Federal onshore (b)	—	—	37,626	37,326	37,626	37,326
Total	21,927	16,687	50,312	48,260	72,239	64,947

(a) A portion of our Texas acreage requires continuous drilling to hold the acreage for which we have included in our development plans, though the cost to renew this acreage, if necessary, is not considered material.

(b) The Company’s lease of this acreage, located in Nevada, expires in 2018 and 2019. The lease requires no drilling activity to hold the acreage, and we continue to evaluate our position and monitor the activity of other operators conducting drilling in the area.

Undeveloped Acreage Expirations

The following table sets forth by geographic area as of December 31, 2014 the number of our leased gross and net undeveloped acres that will expire over the next three years unless production begins before lease expiration dates. Gross amounts may be more than net amounts in a particular year due to timing of expirations.

	Net				Gross
	2015	2016	2017	Total	
Texas					
Southern Permian Basin	165	—	—	165	165
Central Permian Basin	—	—	—	—	—
Northern Permian Basin (a)	7,307	648	—	7,955	10,575
Nevada (b)	—	—	—	—	—
Total	7,472	648	—	8,120	10,740

(a) 7,916 of the total remaining net acres include extension options that would allow us to extend the primary term for a period of two years.
(b) The Company’s lease of this acreage does not expire until 2018 and 2019.

The expiring acreage set forth in the table above accounts for 17% of our net undeveloped acreage (48,260 total net acres) and there are no PUD reserves attributable to such acreage. We are continually engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions, renewals, new drilling and development units and new leases to address any potential expiration of undeveloped acreage that occurs in the normal course of our business.

Title to Properties

The Company believes that the title to its oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. The Company's properties are potentially subject to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements; farm-out agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect the Company's rights to production revenues, these characteristics have been taken into account in calculating Callon's net revenue interests and in estimating the size and value of its reserves. The Company believes that the burdens and obligations affecting our properties are typical within the industry for properties of the kind owned by Callon.

Insurance

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. While not all inclusive, the Company's insurance policies include coverage for general liability insuring onshore operations (including sudden and accidental pollution), aviation liability, auto liability, worker's compensation, and employer's liability. The company carries control of well insurance for only those onshore operations that it is contractually bound to do so. At the depths and in the areas in which the Company operates, and in light of the vertical and horizontal drilling that it undertakes, the Company typically does not encounter high pressures or extreme drilling conditions onshore.

Currently, the Company has general liability insurance coverage up to $1 million per occurrence and $2 million per policy in the aggregate, which includes sudden and accidental pollution liability coverage for the effects of pollution on third parties arising from its operations. The Company's insurance policies contain high policy limits, and in most cases, deductibles (generally ranging from $0 to $250,000) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. The Company maintains up to $100 million in excess liability coverage, which is in addition to and triggered if the underlying liability limits have been reached. In addition, the company purchases pollution legal liability coverage in the amount of $5 million, which is excess and difference in conditions of the liability coverage.

The Company requires all of its third-party contractors to sign master service agreements in which they agree to indemnify the Company for injuries and deaths of the service provider's employees, as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by employees of the Company and the Company's other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for the Company sign master service agreements generally containing the indemnification provisions noted above. The Company does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, the Company believes its general liability and excess liability insurance policies would cover foreseeable third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. While based on the Company's risk analysis, it believes that it is properly insured, no assurance can be given that the Company will be able to maintain insurance in the future at rates that it considers reasonable. In such circumstances, the Company may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Major Customers

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and natural gas production, on an equivalent basis, during each of the 12-month periods indicated:

	For the Year Ended December 31,		
	2014	2013	2012
Enterprise Crude Oil, LLC	51%	38%	32%
Plains Marketing, L.P.	22%	15%	15%
Sunoco	10%	0%	0%
Shell Trading Company	0%	31%	39%
Other	17%	16%	14%
Total	100%	100%	100%

Because alternative purchasers of oil and natural gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on Callon's ability to market future oil and natural gas production. We are not currently committed to provide a fixed and determinable quantity of oil or gas in the near future under our contracts.

Corporate Offices

The Company's headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. We also maintain leased business offices in Houston and Midland, Texas. Because alternative locations to our leased spaces are readily available, the replacement of any of our leased offices would not result in material expenditures**.**

Employees

Callon had 109 employees as of December 31, 2014. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

Regulations

General. Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for amendment and/or expansion. Some of these requirements carry substantial penalties for failure to comply.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the method of drilling and completing and operating wells;
- the rate and method of production;
- the surface use and restoration of properties upon which wells are drilled and other exploration activities;
- notice to surface owners and other third parties;
- the venting or flaring of natural gas;
- the plugging and abandoning of wells;

- the discharge of contaminants into water and the emission of contaminants into air;
- the disposal of fluids used or other wastes obtained in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Operations conducted on federal or state oil and natural gas leases must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Department of the Interior ("DOI") Bureaus or other appropriate federal or state agencies.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Matters and Regulation. Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency ("EPA") issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. Violations of environmental laws could result in administrative, civil or criminal fines and injunctive relief. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Further, the EPA has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2014-2016 and, as a general matter, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. Although such laws and regulations can increase the cost of planning, designing, installing and operating our facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon our operations, capital expenditures, earnings or competitive position in the marketplace.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA and its state analogs, it is possible that some wastes we generate presently or in the future may be subject to regulation under

RCRA and state analogs. Additionally, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in

Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of wastes associated with oil and natural gas exploration and production could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties ("PRPs") include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

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

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," the Safe Drinking Water Act, the Oil Pollution Act ("OPA"), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States (a term broadly defined to include, among other things, certain wetlands), as well as state waters for analogous state programs. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or applicable state analog. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit the discharge of dredge or fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities.

Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state and local laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on April 17, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below in “Regulation of Hydraulic Fracturing.” These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Greenhouse Gas (“GHG”) Regulation. More stringent laws and regulations relating to climate change and GHGs may be adopted in the future and could cause us to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants.

The EPA has established GHG reporting requirements for certain sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although these requirements do not limit the amount of GHGs that can be emitted, they could require us to incur significant costs to monitor, keep records of, and potentially report GHG emissions associated with our operations if the reporting threshold is reached with production growth. The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. Those measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These potential regional and state initiatives may result in so-called “Cap-and-Trade programs”, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, such as by being required to purchase or to surrender allowances for GHGs resulting from our operations. These federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA"), regulates the underground injection of substances through the Underground Injection Control ("UIC"), program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions and not at the federal level, as the SDWA expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid, as further discussed below). Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing have been proposed in recent sessions of Congress but have not passed.

The EPA, however, issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the UIC program, specifically as "Class II" UIC wells. At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources. The EPA has announced that it plans to propose standards in 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

The EPA has adopted regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards for hydraulically fractured natural gas wells to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA may issue revised rules that are likely responsive to some of these requests. If revised, these rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. EPA has announced that it is considering regulations under the Toxic Substance Control Act to require evaluation and disclosure of hydraulic fracturing.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, most notably the EPA's study on the environmental impacts of hydraulic fracturing, the final results of which are not yet available.. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities.

Several states, including Texas, and some municipalities, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water. Further, there has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Surface Damage Statutes ("SDAs"). In addition, a number of states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by oil and gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments to the operator in connection with exploration and operating activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

National Environmental Policy Act and Endangered Species Act. Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA"), which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat or a protected species were located on a lease, it may adversely impact the value of the affected leases.

Mineral Leasing Act of 1920 ("Mineral Act"). The Mineral Act prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign corporation except through stock ownership in a corporation formed under the laws of the United States or of any U.S. state or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or corporations of the United States. If these restrictions are violated, the oil and gas lease or leases can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the Bureau of Land Management ("BLM") (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns an interest in federal leaseholds in Nevada. It is possible that holders of the Company's equity interests may be citizens of foreign countries, which could be determined to be citizens of a non-reciprocal country under the Mineral Act. In such event, the federal onshore oil and gas leases held by the Company could be subject to cancellation based on such determination.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the rates and other terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas sales prices are currently unregulated, the federal government historically has been active in the area of oil and natural gas sales regulation. We cannot predict whether new legislation to regulate oil and natural gas sales might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate, oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the

Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and for the release of our excess, if any, natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by the Company are also subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In August 2011, the PHMSA issued an Advance Notice of Proposed Rulemaking regarding pipeline safety, including questions regarding the modification of regulations applicable to gathering lines in rural areas.

Oil and NGLs Sales and Transportation. Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

The Company's sales of oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by the FERC under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

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

Any transportation of the Company's crude oil, natural gas liquids and purity components (ethane, propane, butane, iso-butane, and natural gasoline) by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180 ("HMR"), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Commitments and Contingencies

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies included, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities. See Note 14 for additional information.

Available Information

We make available free of charge on our Internet web site (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE., Washington, DC 20549. You 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 site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like Callon, that file electronically with the SEC.

We also make available within the Investors section of our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, which have been approved by our board of directors. We will make timely disclosure by a Current Report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: Chief Financial Officer, Callon Petroleum Company, P.O. Box 1287, Natchez, MS 39121.

Item 1A. Risk Factors

Risk Factors

Depressed oil and natural gas prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which are extremely volatile, and the oil and natural gas markets are cyclical. Approximately 80% of our anticipated 2015 production, on a BOE basis, is oil. Starting in the second half of 2014, the NYMEX price for a barrel of oil has fallen sharply, from a price of $105.37 on June 30, 2014 to $49.76 on February 27, 2015. In addition, NYMEX prices for natural gas have been low compared with historical prices. Extended periods of low prices for oil or natural gas will have a material adverse effect on us. The prices of oil and natural gas depend on factors we cannot control such as weather, economic conditions, and levels of production, actions by OPEC and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;

- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our credit facilities;
- the profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and natural gas properties.

Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on our borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows.

If oil and natural gas prices remain depressed for extended periods of time, we may be required to take additional write-downs of the carrying value of our oil and natural gas properties. We may be required to write-down the carrying value of our oil and natural gas properties when oil and natural gas prices are low. Under the full cost method, which we use to account for our oil and natural gas properties, the net capitalized costs of our oil and natural gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and natural gas properties exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. Because the oil price we are required to use to estimate our future net cash flows is the average price over the 12 months prior to the date of determination of future net cash flows, the full effect of falling prices may not be reflected in our estimated net cash flows for several quarters. We review the carrying value of our properties quarterly and once incurred, a write-down of oil and natural gas properties is not reversible at a later date, even if prices increase. See Note 13 to our Consolidated Financial Statements.

Our actual recovery of reserves may substantially differ from our proved reserve estimates and our proved reserve estimates may change over time. This Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. In addition, drilling, testing and production data acquired since the date of an estimate may justify revising an estimate.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas. We incorporate many factors and assumptions into our estimates including:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates;
- Future oil and natural gas prices and quality and locational differences; and
- Future development and operating costs.

You should not assume that any present value of future net cash flows from our estimated net proved reserves contained in this Form 10-K represents the market value of our oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2014 on average 12-month prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. At December 31, 2014, approximately 25% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 45% of total proved reserves by volume. Recovery of PUDs generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Information about reserves constitutes forward-looking information. See “Forward-Looking Statements” for information regarding forward-looking information.

Unless we replace our oil and gas reserves, our reserves and production will decline. Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues, reserve quantities and cash flows will decline. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures, currently expected to be in excess of three times the cost, as compared to the drilling of a traditional vertical well. If we do not replace the reserves we produce, our reserves revenues and cash flow will decrease over time, which will have an adverse effect on our business.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all. Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings under our credit facility and public debt and equity financings. In 2014, our total capital expenditures, including expenditures for leasehold interests and property acquisitions, drilling, seismic and infrastructure, were approximately $455.5 million. Our 2015 capital budget for drilling, completion and infrastructure is estimated to be approximately $150 to $165 million. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower oil or 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 at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our estimated net proved reserves, and could adversely affect our business, financial condition and results of operations.

Our revolving credit facility and second lien term loan facility contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities. Our credit facilities restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- create additional liens;
- sell assets;
- merge or consolidate with another entity;
- pay dividends or make other distributions;
- engage in transactions with affiliates; and
- enter into certain swap agreements.

In addition, we will be required to use substantial portions of our future cash flow to repay principal and interest on our indebtedness. Our credit facilities require us to maintain certain financial ratios and tests, including a minimum asset value coverage ratio of total debt. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

Our borrowings under our revolving credit facility and second lien term loan facility expose us to interest rate risk. Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.75% to 2.75% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. Our second lien term loan bears interest at a rate of LIBOR, subject to a floor of 1%, plus 7.50%. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

The borrowing base under our revolving credit facility may be reduced below the amount of borrowings outstanding under such facilities. Under the terms of our revolving credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing oil and gas prices. A negative adjustment could occur if the estimates of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination. The next redetermination of our borrowing base is scheduled to occur on or about March 31, 2015. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of the revolving credit facility including, without limitation, compliance with the financial performance covenants of such facility. In the event the amount outstanding under our revolving credit facility exceeds the redetermined borrowing base, we are required to either (i) grant liens on additional oil and gas properties (not previously evaluated in determining such borrowing base) with a value equal to or greater than such excess or (ii) repay such excess borrowings over five monthly installments. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, an event of default would occur under our revolving credit facility.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget. From time to time, our industry has experiences a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner. Water is an essential component of our drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local landowners and other sources for use in our operations. During the last few years, West Texas has experienced extreme drought conditions. As a result of the severe drought, some local water districts may begin restricting the use of water under their jurisdiction for drilling and hydraulic fracturing to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGLs and natural gas, which could have an adverse effect on our business, financial condition and results of operations.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area. All of our producing properties are geographically concentrated in the Permian Basin of West Texas. 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, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our exploration projects increase the risks inherent in our oil and natural gas activities. We may seek to replace reserves through exploration, where the risks are greater than in acquisitions and development drilling. Our exploration drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- the results of our exploration drilling activities;
- receipt of additional seismic data or other geophysical data or the reprocessing of existing data;
- material changes in oil or natural gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells; and
- changes to governmental regulations.

Delays in exploration, cost overruns or unsuccessful drilling results could have a material adverse effect on our business and future growth.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive deposits will not be discovered. We may invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that any leasehold acreage acquired will be profitably developed, that new wells drilled will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. We may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling rigs and the delivery of equipment; and
- compliance with governmental requirements.

Failure to conduct our oil and gas operations in a profitable manner may result in write-downs of our proved reserves quantities, impairment of our oil and gas properties, and a write-down in the carrying value of our unproved properties, and over time may adversely affect our growth, revenues and cash flows.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling 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, marketing and transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Approximately 45% of our total estimated proved reserves as of December 31, 2014, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

We maybe unable to integrate successfully the operations of future acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. Our business may include producing property acquisitions that would include undeveloped acreage. We can offer no assurance that we will achieve the desired profitability from any acquisitions we may complete in the future. In addition, failure to assimilate recent and future acquisitions successfully could adversely affect our financial condition and results of operations. Our acquisitions may involve numerous risks, including:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new geographic area;
- risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- loss of significant key employees from the acquired business:
- diversion of management's attention from other business concerns;
- failure to realize expected profitability or growth;
- failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisition and current operations, which in turn, could negatively impact our results of operations.

We may fail to fully identify problems with any properties we acquire, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Texas or other regions in the future. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify. Such assessments are inexact and their accuracy is inherently uncertain. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our ability to conduct business. There are many operating hazards in exploring for and producing oil and natural gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;
- we may experience equipment failures which curtail or stop production;
- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken;
- storms and other extreme weather conditions could cause damages to our production facilities or wells.

Because of these or other events, we could experience environmental hazards, including release of oil and natural gas from spills, natural gas-leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or fracturing fluids, including chemical additives, underground migration, and ruptures.

If we experience any of these problems, it could affect well bores, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses in excess of our insurance coverage as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

Factors beyond our control affect our ability to market production and our financial results. The ability to market oil and natural gas from our wells depends upon numerous factors beyond our control. These factors could negatively affect our ability to market all of the oil or natural gas we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- federal regulations generally prohibiting the export of U.S. crude oil;
- federal regulations applicable to exports of liquefied natural gas (LNG);
- the proximity of hydrocarbon production to pipelines;
- the availability of pipeline capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

In particular, in areas with increasing non-conventional shale drilling activity, capacity may be limited and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built.

The marketability of our production is dependent upon oil and condensate trucking facilities owned and operated by third parties, and the unavailability of these facilities would have a material adverse effect on our revenue. Our ability to market our production depends in substantial part on the availability and capacity of oil and condensate trucking operations owned and operated by third parties. Our failure to obtain these services on acceptable terms could materially harm our business. We may be required to shut in wells for lack of a market or because of inadequate or unavailable trucking capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases.

The disruption of third party trucking facilities due to maintenance, weather or other factors could negatively impact our ability to market and deliver our oil and condensate. The third parties control when, or if, such trucking facilities are restored and what prices will be charged. In the past, we have experienced disruptions in our ability to market oil and condensate from bad weather. We may experience similar interruptions as we continue to explore and develop our Permian Basin properties in the future. If we were required to shut in our production for long periods of time due to lack of trucking capacity, it would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Part of our strategy involves drilling in new or emerging shale formations using horizontal drilling and completion techniques. The results of our planned drilling program in these formations may be subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production. The results of our recent horizontal drilling efforts in new or emerging formations, including certain intervals in the Wolfcamp shale, the Spraberry shale and the Cline shale in the Permian basin, are generally more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis predict our future drilling results. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas from proved properties and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees and our third party consultants, none of whom are subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

We may not be insured against all of the operating risks to which our business is exposed. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable and may elect none or minimal insurance coverage. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations.

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies and smaller independents as well as numerous financial buyers, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties, including the ability to procure fracture stimulation services on wells drilled; and
- our ability to access pipelines, and the location of facilities used to produce and transport oil and natural gas production.

Current or proposed financial legislation and rulemaking 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. Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter derivatives and requires the Commodity Futures Trading Commission (the "CFTC") and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC approved on November 5, 2013, a proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has issued a proposed rule on margin requirements for swap transactions, which proposes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or margin requirements, depending on the Company's ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require us to comply with position limits, margin requirements and with certain clearing and trade-execution requirements in connection with financial derivative activities. The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to financial derivatives to hedge or mitigate their exposure to commodity price volatility. 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 capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and natural gas liquids prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and natural gas liquids. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

We may not have production to offset hedges. Part of our business strategy is to reduce our exposure to the volatility of oil and natural gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged. Additionally, we are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of physical production.

By hedging, we may not benefit from price increases. Hedging can prevent us from receiving the full advantage of increases in oil or natural gas prices above the fixed amount specified in a hedge transaction in the case of a swap. We also enter into price "collars" to reduce the risk of changes in oil and natural gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference. Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. See "Quantitative and Qualitative Disclosures About Market Risks" for a discussion of our hedging practices.

Our hedging transactions expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative 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 derivative contract and we may not be able to realize the benefit of the derivative contract. During periods of falling commodity prices, our hedging transactions expose us to risk of financial loss if our counterparty to a derivatives transaction fails to perform its obligations under a derivatives transaction (e.g., our counterparty fails to perform its obligation to make payments to us under the derivatives transaction when the market (floating) price under such derivative falls below the specified fixed price). 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. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results. Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, advances to joint interest parties and joint interest receivables. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately 51% of our total oil and natural gas revenues for the year ended December 31, 2014. We do not require any of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells.

Compliance with environmental and other government regulations could be costly and could negatively impact production. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see "Regulations." These laws and regulations may:

- require that we acquire permits before commencing drilling;
- impose operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands and wilderness areas; and
- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of and increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. Certain environmental statutes, including the RCRA, CERCLA, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, greenhouse gases and hydraulic fracturing. Under the common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from properties in the event of environmental incidents.

Climate change legislation or regulations restricting emissions of "greenhouse gasses" ("GHG") could result in increased operating costs and reduced demand for the oil and natural gas we produce. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. Those measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and gas production sources and natural gas processing and transmission sources.

In addition, the EPA requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We will have to incur costs associated with this reporting obligation.

In addition, the United States Congress has considered (but not passed) legislation to reduce emissions of GHGs and many states have already taken or have considered legal measures to reduce or measure GHG emissions, often involving the planned development of GHG emission inventories and/or cap and trade programs. Most of these cap and trade programs would require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. These allowances would be expected to escalate significantly in cost over time. The adoption and implementation of any legislation or regulatory programs imposing GHG 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 or could adversely affect demand for the oil and natural gas that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects. In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including storms and floods), the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. Should drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

Federal legislation and state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid). We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells for which we are the operator. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under federal and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. In March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. A progress report was issued in December 2012; a final report is not yet available. The agency also announced that one of its enforcement initiatives for 2014 to 2016 would be to focus on environmental compliance by the energy extraction sector. This study and the EPA's enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

A committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Legislation was introduced before Congress, but not passed to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local or regional regulatory authorities have adopted or are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has announced that it will ban high volume hydraulic fracturing. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. While we have no operations in either New York or Pennsylvania, any other new laws or regulations that significantly restrict hydraulic fracturing in areas in which we do operate could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. Further, the EPA has announced initiatives under the CWA to establish standards of wastewater from hydraulic fracturing and under TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals, and the BLM has indicated that it will continue with rulemaking to regulate hydraulic fracturing on federal lands. In addition, if hydraulic fracturing becomes further regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs and potential liabilities. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

We are now subject to regulation under NSPS and NESHAPS programs, which could result in increased operating costs. On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and the NESHAP programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation. In recent years, the Obama administration's budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (1) the repeal of the percentage depletion allowance for oil and gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for U.S. production activities and (4) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company's financial condition and results of operations.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected. Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

We have no plans to pay cash dividends on our common stock in the foreseeable future. We have no plans to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our credit facilities prohibit us from paying dividends and making other distributions.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations. Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our financial position or results of operations.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II.

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the New York Stock Exchange under the symbol "CPE". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

	Common Stock Price			
	2014		2013	
	High	Low	High	Low
First quarter	$ 9.00	$ 6.13	$ 5.82	$ 3.62
Second quarter	11.75	8.15	4.00	3.19
Third quarter	12.09	8.46	5.49	3.40
Fourth quarter	8.99	4.09	7.60	5.18

Holders

As of February 27, 2015 the Company had approximately 2,995 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date and presently do not expect to declare or pay any cash dividends on our common stock in the foreseeable future as we intend to reinvest our cash flows and earnings into our business. The declaration and payment of dividends is subject to the discretion of our Board of Directors and to certain limitations imposed under Delaware corporate law and the agreements governing our debt obligations. The timing, amount and form of dividends, if any, will depend on, among other things, our results of operations, financial condition, cash requirements and other factors deemed relevant by our Board of Directors. In addition, certain of our debt facilities contain restrictions on the payment of dividends to the holders of our common stock.

Holders of our Series A preferred stock are entitled to a cumulative dividend whether or not declared, of $5.00 per annum, payable quarterly, equivalent to 10.0% of the liquidation preference of $50.00 per share. Unless the full amount of the dividends for the Series A Preferred Stock is paid in full, we cannot declare or pay any dividend on our common stock.

During the fourth quarter of 2014, neither the Company nor any affiliated purchasers made repurchases of Callon's equity securities.

Equity Compensation Plan Information

The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2014 (securities amounts are presented in thousands).

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	15	$ 13.71	1,132
Equity compensation plans not approved by security holders	15	$ 14.37	-
Total	30	$ 14.04	1,132

For additional information regarding the Company's benefit plans and share-based compensation expense, see Notes 8 and 9 to the Consolidated Financial Statements.

Performance Graph

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to four broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph below compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the S&P 500 Index and SIG Oil Exploration & Production Index from December 31, 2009, through December 31, 2014.

The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Comparison of Five Year Cumulative Total Return
Assumes Initial Investment of $100
December 2014

	For the Year Ended December 31,					
Company/Market/Peer Group	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Callon Petroleum Company	$ 100.00	$ 394.67	$ 331.33	$ 313.33	$ 435.33	$ 363.33
S&P 500 Index - Total Returns	100.00	115.06	117.49	136.30	180.44	205.14
SIG Oil Exploration & Production Index	100.00	123.12	111.96	104.20	131.89	94.56

ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2014 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results (dollars in thousands, except per share amounts).

	For the Year Ended December 31,				
	2014	2013	2012	2011	2010
Statement of Operations Data					
Operating revenues					
Oil and natural gas sales	$ 151,862	$ 102,569	$ 110,733	$ 127,644	$ 89,882
Operating expenses					
Total operating expenses	$ 113,592	$ 91,905	$ 100,043	$ 88,022	$ 68,703
Income from continuing operations	38,270	10,664	10,690	39,622	21,179
Net income (a)	37,766	4,304	2,747	106,396	8,386
Earnings (loss) per share ("EPS")					
Basic	$ 0.67	$ (0.01)	$ 0.07	$ 2.81	$ 0.29
Diluted	$ 0.65	$ (0.01)	$ 0.07	$ 2.76	$ 0.28
Weighted average number of shares outstanding for Basic EPS	44,848	40,133	39,522	37,908	28,817
Weighted average number of shares outstanding for Diluted EPS	45,961	40,133	40,337	38,582	29,476
Statement of Cash Flows Data					
Net cash provided by operating activities	$ 94,387	$ 54,475	$ 51,290	$ 79,167	$ 100,102
Net cash used in investing activities	(452,501)	(79,804)	(93,703)	(91,511)	(59,738)
Net cash provided by (used in) financing activities	356,070	27,202	(243)	38,703	(26,252)
Balance Sheet Data					
Total oil and gas properties	$ 742,155	$ 324,187	$ 269,521	$ 215,912	$ 168,868
Total assets	876,770	423,953	378,173	369,707	218,326
Long-term debt (b)	335,000	75,748	120,668	125,345	165,504
Stockholders' equity	433,735	279,094	205,971	201,202	15,810
Proved Reserves Data					
Total oil (MBbls)	25,733	11,898	10,780	10,075	8,149
Total natural gas (MMcf)	42,548	17,751	19,753	35,118	32,957
Total (MBOE)	32,824	14,857	14,072	15,928	13,641
Standardized measure (c)	$ 579,542	$ 283,946	$ 231,148	$ 270,357	$ 198,916

(a) Net income for 2011 includes $69.3 million of income tax benefit related to the reversal of the Company's deferred tax asset valuation allowance. See Note 10 for additional information.

(b) See Note 4 for additional information.

(c) Standardized measure is the future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet. Prices are based on either the preceding 12-months' average price, based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. Future production and development costs are based on current estimates with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% discount rate.

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

General

The following management's discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Form 10-K.

We are an independent oil and natural gas company established in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin in West Texas, and more specifically, the Midland Basin. Our operations to date have been predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through acreage purchases, joint ventures and asset swaps. Our production was approximately 82% oil and 18% natural gas for the year ended December 31, 2014. On December 31, 2014, our net acreage position in the Permian Basin was 27,366 net acres, including 9,301 net acres in the Northern Midland Basin that the Company plans to let expire.

Significant accomplishments for 2014 include:

- Acquired 6,230 gross (3,862 net) surface acres in Midland, Andrews, Martin and Ector Counties for approximately $210 million, which added over 1,300 BOE/d of production and approximately 194 gross (121.6 net) potential horizontal drilling locations (see below);
- Expanded our existing core development areas in Upton and Reagan Counties by acquiring 1,527 net acres for $8.2 million;
- Increased Permian Basin annual production in 2014 by 155% to 2,062 MBOE as compared to 2013;
- Increased 2014 proved reserves by 121% to 32.8 MMBOE as compared to 2013;
- Placed a total of 31 gross horizontal wells on production from four distinct intervals;
- Increased the Credit Facility's borrowing base to $250 million with a syndicate of 10 lending institutions;
- Retired the remaining $48.5 million of the 13% Senior Notes, improving our cost of capital; and
- Completed a common stock offering for $129.4 million in gross proceeds and entered into a new $300 million second lien term loan to partially fund the previously mentioned acquisition and planned capital expenditures.

Acquisition activity

In the first quarter of 2014, the Company acquired 1,527 net acres in Upton and Reagan Counties, Texas, which are located in the Southern Midland Basin near its existing core development fields, for an aggregate cash purchase price of $8.2 million. The properties bear a working interest of 100% and an average net revenue interest of 78%.

On October 8, 2014, the Company completed the acquisition of undeveloped acreage and producing oil and gas properties located in Midland, Andrews, Martin and Ector Counties, Texas. Including estimated purchase price adjustments, total net consideration paid for the acquisition was approximately $210 million for an estimated 62% working interest (46.5% net revenue interest).

Key attributes of the acquired fields in the Central Midland Basin include:

- 6,230 gross (3,862 net) surface acres, 95% of which are located in Midland and Andrews Counties, in close proximity to the Company's existing Carpe Diem and Pecan Acres fields in Midland County
- 194 gross (121.6 net) potential horizontal drilling locations targeting the Wolfcamp B, Lower Spraberry and Middle Spraberry zones which are currently producing in offsetting fields
- 255 gross (159.9 net) additional potential horizontal drilling locations targeting four other prospective zones including the Wolfcamp A, Wolfcamp D (Cline), Clearfork and Jo Mill
- 100% of targeted horizontal zones held by production

The Company assumed operatorship of the properties November 1, 2014 and currently owns an estimated 62.7% working interest after the recent purchase of additional working interests in October 2014. See Note 3 in the Footnotes to the Financial Statements for additional information regarding the acquisition.

Operational Highlights

Following the sale of our remaining producing offshore and Haynesville properties in the fourth quarter of 2013, all of our producing properties are located in the Permian Basin. As a result of our acquisition and horizontal development efforts, our Permian production grew 154% in 2014 compared to 2013, increasing to 2,062 MBOE from 813 MBOE, respectively. Our production in 2014 was approximately 82% oil and 18% natural gas.

	Net Production (MBOE) Twelve Months Ended December 31,			
	2014	2013	Change	% Change
Permian				
Southern Midland Basin	1,497	612	885	145%
Central Midland Basin	549	193	356	184%
Northern Midland Basin	16	8	8	100%
Total	2,062	813	1,249	154%
Offshore and other				
Medusa	—	302	(302)	(100)%
Haynesville shale	—	18	(18)	(100)%
Gulf of Mexico shelf and other	—	280	(280)	(100)%
Total	—	600	(600)	(100)%
Total	2,062	1,413	649	46%

During 2014 we operated two horizontal rigs and one vertical rig. The following table summarizes the Company's drilling activity in the Permian Basin for the year ended December 31, 2014:

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	22	20.1	22	20.1	3	3.0
Total	23	21.1	23	21.1	3	3.0
Central Midland Basin						
Vertical wells	4	1.8	3	1.3	1	0.4
Horizontal wells	5	4.3	9	7.2	—	—
Total	9	6.1	12	8.5	1	0.4
Northern Midland Basin						
Vertical wells	2	1.5	1	0.8	—	—
Total	2	1.5	1	0.8	—	—
Total vertical wells	7	4.3	5	3.1	1	0.4
Total horizontal wells	27	24.4	31	27.3	3	3.0
Total	34	28.7	36	30.4	4	3.4

(a) Completions include wells drilled prior to 2014.

Permian Reserve Growth

As of December 31, 2014, our estimated proved reserves increased 121% to 32.8 MMBOE compared to 14.9 MMBOE of proved reserves at year-end 2013. Our significant growth in proved reserves was primarily attributable to our horizontal development and acquisition efforts. Our proved reserves at year-end 2014 were 78% oil and 22% natural gas, compared to 80% oil and 20% natural gas at year-end 2013.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions, the sale of debt and equity securities and asset dispositions. Our primary uses of capital have been for the acquisition, development, exploration and exploitation of oil and natural gas properties, in addition to refinancing of debt instruments.

During the third and fourth quarters of 2014, we amended the borrowing base under our Credit Facility, entered into a second lien term loan and completed a common stock offering to support the funding of our Central Midland Basin acquisition completed in October 2014 and our ongoing operations and acquisition initiatives which are discussed in greater detail in Notes 5, 10 and 14 in the Footnotes to the Financial Statements. In addition, we regularly evaluate other sources of capital to complement our cash flow from operations and other sources of capital as we pursue our long-term growth plans in the Permian Basin.

Based upon current commodity price expectations for 2015, we believe that our cash flow from operations and borrowings under our Credit Facility and Second Lien Loan will be sufficient to fund our operations for 2015, including any deficiencies in the Company's current net working capital. However, future cash flows are subject to a number of variables, including forecast production volumes and commodity prices. Approximately 95% of our current 2015 capital program is allocated to properties we operate and, as a result, the amount and timing of a substantial portion of our planned capital expenditures is largely discretionary in the event we determine it prudent to curtail drilling and completion operations due to capital constraints or reduced returns on investment in periods of commodity price weakness.

Cash and cash equivalents decreased $2.0 million in the year ended December 31, 2014 to $1.0 million compared to $3.0 million at December 31, 2013. As of February 27, 2015, our available liquidity was $172.0 million.

Liquidity and cash flow

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Net cash provided by operating activities	$ 94.4	$ 54.5	51.3
Net cash used in investing activities	(452.5)	(79.8)	(93.7)
Net cash provided by (used in) financing activities	356.1	27.2	(0.3)
Net change in cash	$ (2.0)	$ 1.9	$ (42.7)

Operating activities. For the year ended December 31, 2014, net cash provided by operating activities was $94.4 million, compared to $54.5 million for the same period in 2013. The increase was primarily due to an increase in oil sales and an increase in gains on the settlement of derivative contracts, partially offset by an increase in production taxes and lease operating expense. Production and realized prices are discussed below in Results of Operations. See Notes 6 and 7 in the Footnotes to the Financial Statements for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. For the year ended December 31, 2014, net cash used in investing activities was $452.5 million compared to $79.8 million for the same period in 2013. Net cash used in investing activities during the year included $232.6 million in capital expenditures (not including acquisition costs), an increase of $72.9 million over 2013, primarily attributable to our drilling and completion activities in the Permian Basin, driven by the addition of a second horizontal drilling rig in August 2013. Net cash used in investing activities also included $222.9 million in acquisition costs, an increase of $212.0 million over 2013. Net cash provided by investing activities included proceeds of $3.0 million received from the sale of certain properties and equipment, an $87.0 million decrease compared to the same period in 2013, when the Company received proceeds of $90.0 million from the sale of Medusa and our other offshore properties. See Note 3 in the Footnotes to the Financial Statements for additional information on acquisitions and dispositions.

2015 Capital Plan

In early February 2015, we announced an operational capital budget for 2015 in the range of $150 to $165 million. This represents a reduction of approximately 25%-30% to the comparable 2014 budgeted amounts in response to a lower oil and natural gas price environment.

We expect our 2015 horizontal drilling program will be primarily focused on program development of established Upper and Lower Wolfcamp B zones and the Lower Spraberry zones in the Southern and Central Midland Basin with lateral lengths ranging from approximately 5,000' to 10,000'.

In addition to the operational capital expenditures above, we budgeted approximately $17.2 million for capitalized general and administrative expenses and certain retained plugging and abandonment expenses related to divested Gulf of Mexico shelf assets.

We are the operator for approximately 95% of our 2015 capital program and, as a result, the amount and timing of these capital expenditures are largely discretionary depending on commodity prices and other factors. We currently expect to fund our 2015 capital program through a combination of cash flow from operations and Credit Facility borrowings.

Financing activities. For the year ended December 31, 2014, net cash provided by financing activities was $356.1 million compared to cash provided by financing activities of $27.2 million during the same period of 2013. Net cash provided by financing activities during the year ended December 31, 2014 included $122.5 million of net proceeds from the issuance of common stock and a net $291.6 million of borrowings on our Credit Facility and Second Lien Loan, offset by a $50.1 million redemption of our Senior Notes. In addition, the Company paid approximately $7.9 million in preferred stock dividends. See Notes 5 and 10 in the Footnotes to the Financial Statements for additional information about the Company's debt and equity offering.

Senior secured revolving credit facility ("Credit Facility")

On March 11, 2014, the Company entered into the Fifth Amended and Restated Credit Agreement to the Credit Facility with a maturity date of March 11, 2019. JPMorgan Chase Bank, N.A. is Administrative Agent, and participating lenders include Regions Bank, Citibank, N.A., Capital One, N.A., KeyBank, N.A., Whitney Bank, IberiaBank, N.A., OneWest Bank, N.A., SunTrust Bank and Royal Bank of Canada. The total notional amount available under the Credit Facility is $500 million. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. In conjunction with the closing of the Acquisition on October 8, 2014, the borrowing base on the Company's Credit Facility was amended to $250 million. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. As of December 31, 2014, the balance outstanding on the Credit Facility was $35.0 million with a weighted-average interest rate of 1.91%, calculated as the LIBOR plus a tiered rate ranging from 1.75% to 2.75%, which is determined based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the borrowing base.

Term loans

On March 11, 2014, the Company entered into a secured term loan in an aggregate amount of up to $125 million, including initial commitments of $100 million and additional availability of $25 million subject to the consent of two-thirds of the lenders and compliance with financial covenants after giving effect to such increase. The term loan had a maturity date of September 11, 2019, and was not subject to mandatory prepayments unless new debt or preferred stock we issued. It was prepayable at the Company's option, subject to a prepayment premium. The prepayment amount was (i) 102% if the prepayment event occurs prior to March 11, 2015, and (ii) 101% if the prepayment event occurs on or after March 15, 2015 but before March 15, 2016, and (iii) 100% for prepayments made on or after March 15, 2016. The term loan was secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement. On April 10, 2014, the Company drew an initial amount of $62.5 million with an original issue discount of 1.0%.

On October 8, 2014, the term loan described above was repaid in full using a new secured second lien term loan (the "Second Lien Loan") in conjunction with the closing of the Central Midland Basin acquisition, resulting in a loss on early extinguishment of debt of $3.1 million. The Second Lien Loan has a maturity date of October 8, 2021. On October 8, 2014, the Company drew an initial amount of $300 million with a discount of 2.0% and an interest rate of 8.5%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.5% per annum. The Second Lien Loan may be prepaid at the Company's option, subject to a prepayment premium. The

prepayment amount is (i) 102% if the prepayment event occurs prior to October 8, 2015, and (ii) 101% if the prepayment event occurs on or after October 8, 2015 but before October 8, 2016, and (iii) 100% for prepayments made on or after October 8, 2016. The Second Lien Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement. The Royal Bank of Canada is Administrative Agent, and participants include several institutional lenders.

13% Senior Notes due 2016 (the "Senior Notes") and deferred credit

On April 11, 2014, the Company completed the full redemption of the remaining $48.5 million principal amount of outstanding Senior Notes using proceeds from the term loan issued on March 11, 2014. The redemption resulted in a net $3.2 million gain on the early extinguishment of debt (including $4.8 million of accelerated deferred credit amortization).

The gain represents the difference between the $50.1 million paid for the redemption of the Senior Notes ($1.6 million of redemption costs, primarily the call premium) and the carrying value of the remaining Senior Notes of $53.3 million (inclusive of $4.8 million of deferred credit). The Company also paid $0.2 million in accrued interest through the redemption date. Upon the redemption, the indenture governing the Senior Notes was discharged in accordance with its terms.

Common Stock Offering

On September 15, 2014, the Company completed an equity offering for $129.4 million in gross proceeds. The offering consisted of 12,500,000 shares of the Company's common stock at a price to the public of $9.00 per share, before underwriting discounts, and the exercise in full by the underwriters of their option to purchase 1,875,000 additional shares of common stock at $9.00 per share. See Note 10 in the Footnotes to the Financial Statements for additional information about the Company's equity offering.

Contractual Obligations

The following table includes the Company's current contractual obligations and purchase commitments:

	Payments due by Period				
	Total	**< 1 Year**	**Years 2 - 3**	**Years 4 - 5**	**>5 Years**
Second Lien Loan	$ 300,000	$ —	$ —	$ —	$ 300,000
Credit Facility	35,000	—	—	35,000	—
Drilling rig leases and related (a)	45,333	16,893	21,930	6,510	—
Office space lease and other commitments	3,130	637	1,219	855	419
Total	$ 383,463	$ 17,530	$ 23,149	$ 42,365	$ 300,419

(a) The <1 Year column includes $3,733 related to the early termination provisions of one of the Company's vertical drilling rigs (See Note 14), and the amount assumes the lessor is unable to re-charter the rig and staffing personnel to another lessee. Should the lessor re-charter the rig and its related personnel to a new lessee, the $3,733 would be reduced by the value of the new lessee's rental payments.

Income Taxes

The Company's income tax expense varies from the statutory rate primarily due to the effect of state income taxes and non-deductible executive compensation expenses. For additional information, see the Income Tax discussion included below in Results of Operations and Note 11 to the Consolidated Financial Statements.

Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	For the Year Ended December 31,						
	2014	2013	Change	% Change	2012	Change	% Change
Net production:							
Oil (MBbls)	1,692	911	781	86%	977	(66)	(7)%
Natural gas (MMcf)	2,220	3,011	(791)	(26)%	3,588	(577)	(16)%
Total (MBOE)	2,062	1,413	649	46%	1,575	(162)	(10)%
Average daily production (BOE/d)	5,648	3,871	1,777	46%	4,303	(432)	(10)%
% oil (BOE basis)	82%	64%			62%		
Average realized sales price:							
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 82.37	$ 97.65	$ (15.28)	(16)%	$ 97.41	$ 0.24	—
Oil (Bbl) (including impact of cash settled derivatives)	84.85	99.32	(14.46)	(15)%	98.86	0.46	—
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 5.63	$ 4.52	$ 1.11	24%	$ 3.94	$ 0.58	15%
Natural gas (Mcf) (including impact of cash settled derivatives)	5.59	4.47	1.12	25%	3.94	0.53	13%
Total (BOE) (excluding impact of cash settled derivatives)	$ 73.65	$ 72.59	$ 1.06	1%	$ 69.43	$ 3.16	5%
Total (BOE) (including impact of cash settled derivatives)	75.64	73.56	2.08	3%	70.41	3.15	4%
Oil and natural gas revenues (in thousands):							
Oil revenue	$139,374	$ 88,960	$ 50,414	57%	$ 96,584	$(7,624)	(8)%
Natural gas revenue	12,488	13,609	(1,121)	(8)%	14,149	(540)	(4)%
Total	$151,862	$102,569	$ 49,293	48%	$110,733	$(8,164)	(7)%
Additional per BOE data:							
Sales price	$ 73.65	$ 72.59	$ 1.06	1%	$ 69.43	$ 3.16	5%
Lease operating expense	10.85	14.00	(3.15)	(23)%	14.81	(0.81)	(5)%
Production taxes	4.35	2.92	1.43	49%	2.05	0.87	42%
Operating margin	$ 58.45	$ 55.67	$ 2.78	5%	$ 52.57	$ 3.10	6%

Revenues

The following tables are intended to reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices, as well as the impact of our hedge program for the year ended December 31, 2012 when we had designated our derivative contracts as accounting hedges.

(in thousands)	Oil	Natural Gas	Total
Revenues for the year ended December 31, 2011	$ 100,962	$ 26,682	$ 127,644
Volume increase (decrease)	(1,926)	(7,840)	(9,766)
Price increase (decrease)	(3,872)	(4,693)	(8,565)
Impact of hedges	1,420	—	1,420
Net increase (decrease) in 2012	(4,378)	(12,533)	(16,911)
Revenues for the year ended December 31, 2012	$ 96,584	14,149	110,733
Volume increase (decrease)	(6,528)	(2,278)	(8,806)
Price increase (decrease)	(1,096)	1,738	642
Net increase (decrease) in 2013	(7,624)	(540)	(8,164)
Revenues for the year ended December 31, 2013	$ 88,960	$ 13,609	$ 102,569
Volume increase (decrease)	76,237	(3,575)	72,662
Price increase (decrease)	(25,823)	2,454	(23,369)
Net increase (decrease) in 2014	50,414	(1,121)	49,293
Revenues for the year ended December 31, 2014	$ 139,374	$ 12,488	$ 151,862

Oil revenue

For the year ended December 31, 2014, oil revenues of $139.4 million increased $50.4 million, or 57%, compared to revenues of $89.0 million for the same period of 2013. The increase primarily related to an 86% increase in total production, while the average realized sales price decreased 16%. The increase in production was wholly attributable to a 1,048 MBbls increase in Permian production resulting from an increased number of producing wells from acquisitions and our horizontal drilling program offset by normal and expected declines from our existing wells. Partially offsetting the Permian increase was a 267 MBbls decline in production due to the sale of our deepwater Medusa field in the fourth quarter of 2013.

For the year ended December 31, 2013, oil revenues of $89.0 million decreased $7.6 million, or 8%, compared to revenues of $96.6 million for the same period of 2012. Lower production from our offshore properties, primarily related to the sale of Habanero field in December 2012 and our Medusa and shelf properties in the fourth quarter of 2013, drove the revenue decline. Also contributing to the production decline were 20 days of down time for scheduled downstream pipeline maintenance at our Medusa field in the second quarter of 2013, approximately five days of production downtime at our key producing Permian Basin fields in the fourth quarter of 2013 due to severe winter weather causing electricity outages and the extended curtailment of trucking capacity to transport offtake and due to normal and expected declines from other producing wells. Collectively, these declines were offset by the 222 MBbls increase in our oil production from our Permian properties.

Natural gas revenue (including NGLs)

Natural gas revenues of $12.5 million decreased $1.1 million, or 8%, during the year ended December 31, 2014 compared to $13.6 million for the same period of 2013. The average realized price increased to $5.63 per Mcf from $4.52 per Mcf, or 24%, while total production decreased 26%. The decrease in production was primarily attributable to a 1,919 MMcf decrease in production due to the sale of our offshore fields and Haynesville property in the fourth quarter of 2013. Offsetting the production decline was a 1,128 MMcf increase in production from our Permian properties resulting from an increased number of producing wells as mentioned above.

Natural gas revenues of $13.6 million decreased $0.5 million, or 4%, during the year ended December 31, 2013 compared to $14.1 million for the same period of 2012. While the average realized price increased 15%, a 16% decrease in production reduced total revenue. The production declines were primarily attributable to the shut-in of production of our Mobile Bay 908 property, the sale of our offshore fields, the sale of our Haynesville property in the fourth quarter of 2013 as well as normal and expected declines from our existing wells. Offsetting these declines was a 248 MMcf increase in horizontal well production from our Permian properties.

Operating Expenses

	For the Year Ended December 31,							
		Per		Per	Total Change		BOE Change	
	2014	BOE	2013	BOE	$	%	$	%
Lease operating expenses	**$ 22,372**	$ 10.85	**$ 19,779**	$ 14.00	2,593	13%	(3.15)	(22)%
Production taxes	**8,973**	4.35	**4,133**	2.92	4,840	117%	1.43	49%
Depreciation, depletion and amortization	**56,724**	27.51	**43,967**	31.12	12,757	29%	(3.61)	(12)%
General and administrative	**25,109**	12.18	**20,534**	14.53	4,575	22%	(2.35)	(16)%
Accretion expense	**826**	0.40	**1,785**	1.26	(959)	(54)%	(0.86)	(68)%
Gain on sale of other property and equipment	**(1,080)**	(0.52)	**—**	—	(1,080)	—	(0.52)	—
Impairment of other property and equipment	**—**	—	**1,707**	1.21	(1,707)	(100)%	(1.21)	(100)%
Acquisition expense	**668**	0.32	**—**	—	668	—	0.32	—

	For the Year Ended December 31,							
		Per		Per	Total Change		BOE Change	
	2013	BOE	2012	BOE	$	%	$	%
Lease operating expenses	**$ 19,779**	$ 14.00	**$ 23,330**	$ 14.81	(3,551)	(15)%	(0.81)	(5)%
Production taxes	**4,133**	2.92	**3,224**	2.05	909	28%	0.87	42%
Depreciation, depletion and amortization	**43,967**	31.12	**49,701**	31.56	(5,734)	(12)%	(0.44)	(1)%
General and administrative	**20,534**	14.53	**20,358**	12.93	176	1%	1.60	12%
Accretion expense	**1,785**	1.26	**2,253**	1.43	(468)	(21)%	(0.17)	(12)%
Impairment of other property and equipment	**1,707**	1.21	**1,177**	0.75	530	45%	0.46	61%

Lease operating expenses ("LOE"). These are daily costs incurred to extract oil and natural gas out of the ground and deliver to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

LOE for the year ended December 31, 2014 increased by 13% to $22.4 million compared to $19.8 million for the same period of 2013 primarily due to $9.7 million in costs related to the growth in Permian production and operations, including an increase in workover expenses associated with the impact of accelerated horizontal well activity on surrounding producing wells. These increases were partially offset by a decrease in costs of $7.1 million resulting from the sale of our deep water Medusa field and our other offshore fields. LOE per BOE for the year ended December 31, 2014 decreased by 22% to $10.85 per BOE from $14.00 per BOE for the same period of 2013. The 22% decrease is primarily attributable to a 46% increase in production while keeping expenses in line.

LOE for the year ended December 31, 2013 decreased by 15% to $19.8 million compared to $23.3 million for the same period of 2012. The decrease was primarily due to $3.4 million of remediation costs on our Haynesville property in 2012, for which we had no similar costs in 2013, and an estimated decrease of $3.2 million of LOE resulting from the sale of our interests in Habanero, Medusa, the Medusa Spar facilities, our Haynesville property and substantially all our remaining shelf properties. These decreases were partially offset by $3.0 million in LOE costs related to the growth in Permian production and operations, including an increase in workover expenses associated with accelerated horizontal well activity.

Production taxes. Production taxes include severance and ad valorem taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. 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 gas properties.

For the year ended December 31, 2014, production taxes increased 117%, or $4.9 million, to $9.0 million compared to $4.1 million for the same period of 2013. The increase was predominantly attributable to an increase in onshore production subject to these taxes accompanied by a decline in offshore production, resulting from the sale of our Gulf of Mexico position in 2013, which was exempt from production taxes.

For the year ended December 31, 2013 production taxes of $4.1 million increased 28%, or $0.9 million, compared to $3.2 million for the same period of 2012. The increase was predominantly attributable to the previously mentioned increase in onshore production
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subject to these taxes and a decline in offshore production, resulting from the sale of our Gulf of Mexico position in 2013, which is exempt from production taxes.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unevaluated properties, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. 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.

For the year ended December 31, 2014, DD&A increased 29% from $44.0 million compared to $56.7 million for the same period of 2013. The increase is primarily attributable to a 46% increase in production, offset by a 12% decrease in our per BOE DD&A rate. For the year ended December 31, 2014, DD&A on a per unit basis decreased to $27.51 per BOE compared to $31.12 per BOE for the same period of 2013 as a result of our increase in our estimated proved reserves relative to our depreciable base as a result of our efforts on development, exploration, and exploitation of onshore oil and natural gas reserves in the Permian Basin.

For the year ended December 31, 2013, DD&A of $31.12 per BOE remained relatively flat compared to $31.56 per BOE for the same period of 2012.

General and administrative, net of amounts capitalized ("G&A"). 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, franchise taxes, depreciation of corporate level assets, public company costs, vesting of equity and liability awards under share-based compensation plans and related mark-to-market valuation adjustments over time, fees for audit and other professional services and legal compliance.

G&A for the year ended December 31, 2014 increased to $25.1 million (including $3.1 million in fair value adjustment of cash-settled RSU awards) compared to $20.5 million (including $2.9 million in fair value adjustment of cash-settled RSU awards) for the same period of 2013. The increase was primarily related to the following items:

- $1.4 million in non-recurring, cash expenses related to a threatened proxy contest incurred in 2014
- $2.5 million in non-recurring expenses (both cash and non-cash components) primarily related to the accelerated vesting of outstanding equity awards for early retirement of employees

- an increase of $0.2 million related to the fair value adjustment of cash-settled RSU awards

G&A for the year ended December 31, 2013 remained relatively flat at $20.5 million (including $2.9 million in fair value adjustment of cash-settled RSU awards) compared to $20.4 million (including $1.6 million in fair value adjustment of cash-settled RSU awards) for the same period of 2012. The $0.1 million increase was related to the following items:

- an increase of $1.3 million related to the fair value adjustment of cash-settled RSU awards
- a decrease of $1.6 million primarily related to non-recurring employee-related expenses including early retirement and severance expense incurred in 2012

Accretion expense. The Company is required to record the estimated fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations ("ARO") and reported as accretion expense within operating expenses in the consolidated statements of operations.

Accretion expense related to our ARO decreased 54% for the year ended December 31, 2014 compared to the same period of 2013. The decrease in accretion expense correlates with the Company's average ARO, which was $6.5 million during 2014 versus $11.5 million during 2013. The reduction in our average ARO was primarily a result of the divestiture of our offshore fields in the fourth quarter of 2013. See Note 12 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Accretion expense related to our asset retirement obligation decreased 21% for the year ended December 31, 2013 compared to the same periods of 2012. Accretion expense generally correlates directionally with the Company's ARO which was $6.7 million at December 31, 2013 versus $13.3 million at December 31, 2012.

Acquisition expense

Acquisition expense of $0.7 million for the year ended December 31, 2014 relates to acquisition related costs with respect to our acquisition efforts in the Permian Basin. See Note 3 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions.

Gain on sale of other property and equipment

See Note 14 in the Footnotes to the Financial Statements for a discussion of the gain on the sale of specialized deep water property and equipment.

Impairment of other property and equipment

See Note 14 in the Footnotes to the Financial Statements for a discussion regarding the recognition of the impairment on specialized deep water property and equipment.

Other Income and Expenses and Preferred Stock Dividends

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our credit facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense. The amortization of the deferred credit related to our 13% Senior Notes was recorded as an offset to interest expense.

Gain/Loss on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil and natural gas. This amount represents the (i) gain (loss) related to fair value adjustments on our open derivative contracts and (ii) gains (losses) on settlements of derivative contracts for positions that have settled within the period. We provide a reconciliation of these components of the gain/loss on derivative contracts in Note 5.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when 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 the rate change is enacted. When appropriate based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

	For the Year Ended December 31,			
	2014	2013	$ Change	% Change
Interest expense	$ 9,772	$ 6,094	$ 3,678	60%
Gain on early extinguishment of debt	(151)	(3,696)	3,545	(96)%
(Gain) loss on derivative contracts	(31,736)	1,360	(33,096)	(2,434)%
Other income, net	(515)	(485)	(30)	6%
Total	$ (22,630)	$ 3,273		
Income tax expense	$ 23,134	$ 3,104	$ 20,030	645%
Equity in earnings of Medusa Spar LLC	—	17	(17)	(100)%
Preferred stock dividends	(7,895)	(4,627)	(3,268)	71%

	For the Year Ended December 31,			
	2013	2012	$ Change	% Change
Interest expense	$ 6,094	$ 9,108	(3,014)	(33)%
Gain on early extinguishment of debt	(3,696)	(1,366)	(2,330)	171%
Loss (gain) on derivative contracts	1,360	(1,717)	3,077	(179)%
Other income, net	(485)	(79)	(406)	514%
Total	$ 3,273 -	$ 5,946 -	-	
Income tax expense	$ 3,104	$ 2,223	$ 881	(40)%
Equity in earnings of Medusa Spar LLC	17	226	(209)	(92)%
Preferred stock dividends	(4,627)	—	(4,627)	—

Interest expense

Interest expense incurred during the year ended December 31, 2014 increased $3.7 million to $9.8 million compared to $6.1 million for the same period of 2013. The increase is primarily attributable to the $11.4 million increase in expense related to additional draws on our Credit Facility and term loans in 2014 compared to the corresponding period of the prior year. Offsetting the increase is a $7.9 million decrease in interest expense related to our Senior Notes following a $48.5 million partial redemption during the fourth quarter of 2013 and a full redemption of the remaining outstanding principal in April 2014. Also offsetting the increase was a $0.2 million increase in capitalized interest, resulting from a higher average unevaluated property balance period over period.

Interest expense incurred during the year ended December 31, 2013 decreased $3.0 million to $6.1 million compared to $9.1 million for the same period of 2012. The decrease was related primarily to an additional $2.3 million of interest capitalized in 2013 versus 2012, approximately $0.3 million of reduced interest payments attributable to the redemption of $48.5 million principal of the Company's Senior Notes in December 2013 and $0.1 million of additional deferred credit amortization recognized in 2013 compared with 2012. The additional capitalized interest was related to a higher balance year-over-year in average unevaluated oil and natural gas properties following the purchase of additional unevaluated acreage and exploration costs incurred in the Permian Basin.

(Gain) loss on early extinguishment of debt

During April 2014, the Company completed a full redemption of the remaining $53.3 million carrying value of its outstanding Senior Notes using proceeds from the issuance of a secured second lien term loan. The carrying value included $48.5 million of principal value and $4.8 million of unamortized deferred credit. The Company recognized a net $3.2 million gain on early extinguishment of debt, comprised of the recognition of $4.8 million in deferred credit, offset by $1.6 million of redemption expenses. See Note 5 for additional information concerning the gain on early extinguishment of debt.

During October 2014, the Company repaid in full the existing term loan using proceeds from the Second Lien Loan resulting in a loss on early extinguishment of debt of $3.1 million. The loss was comprised of a $1.7 million prepayment premium and the recognition of $1.4 million of unamortized issuance costs. See Note 5 for additional information concerning the loss on the early extinguishment of debt.

During December 2013, the Company redeemed $53.8 million carrying value of its Senior Notes using a portion of the proceeds from the Company's May 2013 preferred equity offering. The $53.8 million of carrying value included $48.5 million of principal value and $5.3 million of unamortized deferred credit. The Company recognized a net gain of $3.7 million on the early extinguishment of debt, comprised of the recognition of $5.3 million in deferred credit, offset by $1.6 million of redemption expenses.

Loss (gain) on derivative contracts

For the year ended December 31, 2014, the net gain on derivative instruments was $31.7 million, compared to a $1.4 million net loss in 2013. See Notes 6 and 7 in the Footnotes to the Financial Statements for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

For the year ended December 31, 2013, the net loss on derivative instruments was $1.4 million, compared to a $1.7 million net gain in 2012.

Income tax expense

The effective tax rate of 38% in 2014 and 42% in 2013 differed from the federal income tax rate of 35% primarily due to the effect of state taxes, non-deductible executive compensation expenses and percentage depletion. For additional information, see Note 11 to the Consolidated Financial Statements.

Preferred stock dividends

Preferred stock dividends for the year ended December 31, 2014 increased $3.3 million compared to the same period of 2013. We issued the Preferred Stock on May 30, 2013. Accordingly, the year ended December 31, 2014 reflects dividends for the entire year compared to a partial year in 2013. Dividends reflect a 10% dividend rate and $79 million liquidation value. See Note 10 in the Footnotes to the Financial Statements for additional information.

Summary of Significant Accounting Policies and Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some 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. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for a discussion of additional accounting policies and estimates made by management.

Oil and natural gas properties

The Company utilizes the full cost method of accounting for its oil and natural gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves, including certain overhead costs, are capitalized into the "full cost pool." The amounts capitalized into the full cost pool are depleted (charged against earnings) using the unit-of-production method. The full cost method of accounting for oil and natural gas properties requires that the Company makes estimates based on its assumptions of future events that could change. These estimates are described below.

Depreciation, depletion and amortization (DD&A) of oil and natural gas properties

The Company calculates DD&A by using the depletable base, which is equal to the net capitalized costs in our full cost pool plus estimated future development costs, and the estimated net proved reserve quantities. Capitalized costs added to the full cost pool include the following:

- costs of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and natural gas properties;
- payroll costs including the related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and natural gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs do not include any costs related to the production of oil and natural gas or general corporate overhead;
- costs associated with unevaluated properties, those lacking proved reserves, are excluded from the depletable base. These unevaluated property costs are added to the depletable base at such time as wells are completed on the properties or management determines these costs have been impaired. The Company's determination that a property has or has not been impaired (which is discussed below) requires assumptions about future events;
- estimated costs to dismantle, abandon and restore properties that are capitalized to the full cost pool when the related liabilities are incurred (see also the discussion below regarding Asset Retirement Obligations);
- estimated future costs to develop proved properties are added to the full cost pool for purposes of the DD&A computation. The Company uses assumptions based on the latest geologic, engineering, regulatory and cost data available to it to estimate these amounts. However, the estimates made are subjective and may change over time. The Company's estimates of future development costs are reviewed at least annually and as additional information becomes available; and
- capitalized costs included in the full cost pool plus estimated future development costs are depleted and charged against earnings using the unit-of-production method. Under this method, the Company estimates the proved reserves quantities at the beginning of each accounting period. For each BOE produced during the period, the Company records a DD&A charge equal to the amount included in the depletable base (net of accumulated depreciation, depletion and amortization) divided by our estimated net proved reserve quantities.

Because the Company uses estimates and assumptions to determine proved reserves (as discussed below) and the amounts included in the depletable base, our depletion rates may materially change if actual results differ from these estimates.

Ceiling test

Under the full cost method of accounting, the Company compares, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and natural gas properties net of related deferred taxes. The Company refers to this comparison as a "ceiling test." If the net capitalized costs of proved oil and natural gas properties exceed the estimated discounted (at a 10% annualized rate) future net cash flows from proved reserves, the Company is required to write-down the value of its oil and natural gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are based on a twelve-month average pricing assumption. Given the volatility of oil and natural gas prices, it is reasonably possible that the Company's estimates of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices remain at current levels or decline further, even if only for a short period of time, write-downs of oil and natural gas properties could occur in the future. See Note 13 for additional information regarding the Company's oil and natural gas properties.

Estimating reserves and present value of estimated future net cash flows

Estimates of quantities of proved oil and natural gas reserves, including the discounted present value of estimated future net cash flows from such reserves at the end of each quarter, are based on numerous assumptions, which are likely to change over time. These assumptions include:

- the prices at which the Company can sell its oil and natural gas production in the future. Oil and natural gas prices are volatile, but we are required to assume that they remain constant, using the twelve-month average pricing assumption. In general, higher oil and natural gas prices will increase quantities of proved reserves and the present value of estimated future net cash flows from such reserves, while lower prices will decrease these amounts; and
- the costs to develop and produce the Company's reserves and the costs to dismantle its production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that they remain constant. Increases in costs will reduce estimated oil and natural gas quantities and the present value of estimated future net cash flows, while decreases in costs will increase such amounts.

Changes in these prices and/or costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and natural gas reserves for the Company's properties that have relatively short productive lives. If oil and natural gas prices remain at current levels or decline further, it will have a negative impact on the present value of estimated future net cash flows and the estimated quantities of oil and natural gas reserves.

In addition, the process of estimating proved oil and natural gas reserves requires that the Company's independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and natural gas prices under "Risk Factors."

Sales of oil and natural gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Unproved properties

Costs, including capitalized interest, associated with properties that do not have proved reserves are excluded from the depletable base, and are included in the line item "Unevaluated properties." Unevaluated property costs are transferred to the depletable base when wells are completed on the properties or management determines that these costs have been impaired. In addition, the Company is required to determine whether its unevaluated properties are impaired and, if so, include the costs of such properties in the depletable base. The Company determines whether an unevaluated property is impaired by periodically reviewing its exploration program on a property-by-property basis. This determination may require the exercise of substantial judgment by management.

Asset retirement obligations

We are required to record our estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-life assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 12 for additional information.

Derivatives

To manage oil and natural gas price risk on a portion of our planned future production, we have historically utilized commodity derivative instruments (including collars, swaps, puts, and other structures) on approximately 50% to 75% of our projected production volumes in any given year. We do not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price and prices specified in the derivative instrument and a NYMEX price or other cash or futures index price.

We elected to no longer designate derivative contracts executed after January 1, 2012 as accounting hedges and as such our derivative positions are carried at their fair value on the balance sheet with changes in fair value recorded through earnings.

Derivative contracts that were entered into at and prior to December 31, 2011 were accounted for as cash flow hedges, and were recorded at fair value on our consolidated balance sheet. Changes in fair value were recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The changes in fair value related to ineffective derivative contracts were recognized as derivative expense (income). The estimated fair value of our derivative contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options. For additional information regarding derivatives and their fair values, see Notes 6 and 7 to the Consolidated Financial Statements and Part II, Item 7A Commodity Price Risk.

Income taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). See Note 11 for additional information regarding Income Taxes.

Recent Accounting Standards

In May 2014, the FASB issued accounting standards update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. The guidance in ASU No. 2014-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk. The total volumes which we hedge through the use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 50% to 75% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices, in addition to modification of our capital spending plans related to operational activities and acquisitions.

As of February 27, 2015, we had commodity contracts covering approximately 63% and 62% of our expected oil and natural gas production for calendar year 2015, respectively, based on the midpoint of publicly disclosed guidance as of March 4, 2015 and including the impact of derivative contracts established after December 31, 2014. Our short call options related to natural gas have been integrated with swaps for purposes of this calculation. Our actual production will vary from the amounts estimated, perhaps materially. See Note 6 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at December 31, 2014 and derivative contracts established subsequent to that date.

The Company may utilize fixed price swaps, which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales. Additionally, the Company may sell put options or call options in conjunction with a swap and use the proceeds to increase the fixed price received.

The Company may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counterparty receives the difference from the Company. Additionally, the Company may sell put options at a price lower than the floor price in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices.

The Company may purchase put options, which reduce the Company's exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company's derivative positions are designated as hedges for accounting purposes.

Interest rate risk

On December 31, 2014, the Company's debt consisted of $300.0 million related to its Second Lien Facility and $35.0 million related to its Credit Facility. The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under the Second Lien Loan and Credit Facility. As of December 31, 2014, the weighted average interest rate on our Credit Facility borrowings was 1.91% and the interest rate on our Second Lien Loan borrowings was 8.50%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $3.4 million based on the $335.0 million outstanding in the aggregate under the two facilities on December 31, 2014. The Company is also subject to market risk exposure going forward related to changes in interest rate for the Second Lien Loan and Credit Facility. See Note 5 to the Consolidated Financial Statements for more information on the Company's interest rates on debt.

Counterparty and customer credit risk

The Company's principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

The Company markets receivables from the sale of our oil and natural gas production to energy marketing companies. We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the year ended December 31, 2014, three purchasers accounted for more than 10% of our revenue: Enterprise Crude Oil, LLC (51%); Plains Marketing, L.P. (22%); and Sunoco (10%). We do not require any of our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At December 31, 2014 our total receivables from the sale of our oil and natural gas production were approximately $18.9 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At December 31, 2014 our joint interest receivables were approximately $6.9 million.

At December 31, 2014 our receivables resulting from derivative contracts were approximately $4.1 million. Our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. The counterparties on our derivative instruments currently in place are lenders under our revolving credit facility. We are likely to enter into additional derivative instruments with these or other lenders under our revolving credit facility, representing institutions with an investment grade ratings. We have existing International Swap Dealers Association Master Agreements ("ISDA Agreements") with our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of offset upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may offset all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. At December 31, 2014 we had a net derivative asset position of $27.9 million and a net derivative liability position of $1.3 million.

ITEM 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Callon Petroleum Company as of December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Callon Petroleum Company's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 4, 2015, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 4, 2015

Part I. Financial Information
Item I. Financial Statements

Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except par and per share values and share data)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 968	$ 3,012
Accounts receivable	30,198	20,586
Deferred tax asset	—	3,843
Fair value of derivatives	27,850	60
Other current assets	1,441	2,063
Total current assets	60,457	29,564
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,077,985	1,701,577
Less accumulated depreciation, depletion and amortization	(1,478,355)	(1,420,612)
Net oil and natural gas properties	599,630	280,965
Unevaluated properties	142,525	43,222
Total oil and natural gas properties	742,155	324,187
Other property and equipment, net	7,118	7,255
Restricted investments	3,810	3,806
Deferred tax asset	44,688	57,765
Deferred financing costs	18,200	1,098
Other assets, net	342	278
Total assets	$ 876,770	$ 423,953
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 76,753	$ 53,447
Accrued interest	5,993	17
Cash-settled restricted stock unit awards	3,856	4,173
Asset retirement obligations	4,747	4,120
Deferred tax liability	6,214	—
Fair value of derivatives	1,249	1,036
Total current liabilities	98,812	62,793
13% senior notes:		
Principal outstanding	—	48,481
Deferred credit, net of accumulated amortization of $0 and $26,239, respectively	—	5,267
Total 13% senior notes	—	53,748
Senior secured revolving credit facility	35,000	22,000
Secured second lien term loan	300,000	—
Asset retirement obligations	1,927	2,612
Cash-settled restricted stock unit awards	7,175	3,409
Other long-term liabilities	121	297
Total liabilities	443,035	144,859
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,578,948 and 1,578,948 shares outstanding, respectively	16	16
Common stock, $0.01 par value, 110,000,000 and 60,000,000 shares authorized; 55,225,288 and 40,345,456 shares outstanding, respectively	552	404
Capital in excess of par value	526,162	401,540
Accumulated deficit	(92,995)	(122,866)
Total stockholders' equity	433,735	279,094
Total liabilities and stockholders' equity	$ 876,770	$ 423,953

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

Callon Petroleum Company
Consolidated Statements of Operations
(in thousands, except per share data)

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Operating revenues:			
Oil sales	$ 139,374	$ 88,960	$ 96,584
Natural gas sales	12,488	13,609	14,149
Total operating revenues	151,862	102,569	110,733
Operating expenses:			
Lease operating expenses	22,372	19,779	23,330
Production taxes	8,973	4,133	3,224
Depreciation, depletion and amortization	56,724	43,967	49,701
General and administrative	25,109	20,534	20,358
Accretion expense	826	1,785	2,253
Gain on sale of other property and equipment	(1,080)	—	—
Impairment of other property and equipment	—	1,707	1,177
Acquisition expense	668	—	—
Total operating expenses	113,592	91,905	100,043
Income from operations	38,270	10,664	10,690
Other (income) expenses:			
Interest expense	9,772	6,094	9,108
Gain on early extinguishment of debt	(151)	(3,696)	(1,366)
(Gain) loss on derivative contracts	(31,736)	1,360	(1,717)
Other income	(515)	(485)	(79)
Total other (income) expense	(22,630)	3,273	5,946
Income before income taxes	60,900	7,391	4,744
Income tax expense	23,134	3,104	2,223
Income before equity in earnings of Medusa Spar LLC	37,766	4,287	2,521
Equity in earnings of Medusa Spar LLC	—	17	226
Net income	37,766	4,304	2,747
Preferred stock dividends	(7,895)	(4,627)	—
Income (loss) available to common stockholders	$ 29,871	$ (323)	$ 2,747
Income (loss) per common share:			
Basic	$ 0.67	$ (0.01)	$ 0.07
Diluted	$ 0.65	$ (0.01)	$ 0.07
Shares used in computing income (loss) per common share:			
Basic	44,848	40,133	39,522
Diluted	45,961	40,133	40,337

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

Callon Petroleum Company
Consolidated Statements of Comprehensive Income
(in thousands)

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Net income	$ 37,766	$ 4,304	$ 2,747
Other comprehensive income (loss):			
Change in fair value of derivatives designated as hedges, net of tax	—	—	(1,624)
Comprehensive income	37,766	4,304	1,123
Preferred stock dividends	(7,895)	(4,627)	—
Comprehensive income (loss) available to common shareholders	$ 29,871	$ (323)	$ 1,123

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

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(in thousands)

	Preferred Stock	Common Stock	Capital in Excess of Par	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity
Balance at 12/31/2011	$ —	$ 394	$ 324,474	$ 1,624	$(125,290)	$ 201,202
Comprehensive income:						
Net income	—	—	—	—	2,747	
Other comprehensive loss	—	—	—	(1,624)	—	
Total comprehensive income	—	—	—	—	—	1,123
Shares issued pursuant to employee benefit plans	—	—	235	—	—	235
Restricted stock	—	4	3,407	—	—	3,411
Balance at 12/31/2012	$ —	$ 398	$ 328,116	$ —	$(122,543)	$ 205,971
Comprehensive income:						
Net income and comprehensive income	—	—	—	—	4,304	4,304
Shares issued pursuant to employee benefit plans	—	—	243	—	—	243
Restricted stock	—	6	3,162	—	—	3,168
Preferred stock issued	16	—	70,019	—	—	70,035
Preferred stock dividend	—	—	—	—	(4,627)	(4,627)
Balance at 12/31/2013	$ 16	$ 404	$ 401,540	$ —	$(122,866)	$ 279,094
Comprehensive income:						
Net income and comprehensive income	—	—	—	—	37,766	37,766
Shares issued pursuant to employee benefit plans	—	—	262	—	—	262
Restricted stock	—	4	2,054	—	—	2,058
Common stock issued	—	144	122,306	—	—	122,450
Preferred stock dividend	—	—	—	—	(7,895)	(7,895)
Balance at 12/31/2014	$ 16	$ 552	$ 526,162	$ —	$ (92,995)	$ 433,735

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

Callon Petroleum Company
Consolidated Statements of Cash Flows
(in thousands)

	For the Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$ 37,766	$ 4,304	$ 2,747
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	58,014	45,393	51,043
Accretion expense	826	1,785	2,253
Amortization of non-cash debt related items	1,272	471	402
Amortization of deferred credit	(487)	(3,164)	(3,086)
Equity in earnings of Medusa Spar LLC	—	(17)	(226)
Deferred income tax expense	23,134	2,778	2,223
Net loss (gain) on derivatives, net of settlements	(27,650)	2,730	(1,683)
Impairment of other property and equipment	—	1,707	1,176
Gain on sale of other property and equipment	(1,080)	—	—
Non-cash gain on early debt extinguishment	(151)	(3,696)	(1,366)
Non-cash expense related to equity share-based awards	1,126	2,092	1,697
Change in the fair value of liability share-based awards	3,936	2,903	1,620
Payments to settle asset retirement obligations	(3,808)	(721)	(1,314)
Changes in current assets and liabilities:			
Accounts receivable	(7,915)	(3,497)	(883)
Other current assets	622	(560)	100
Current liabilities	12,805	3,583	1,753
Payments to settle vested liability share-based awards	(3,469)	(239)	(3,383)
Change in other long-term liabilities	(106)	(711)	103
Change in other assets, net	(448)	(666)	(1,886)
Net cash provided by operating activities	94,387	54,475	51,290
Cash flows from investing activities:			
Capital expenditures	(232,596)	(159,724)	(133,299)
Acquisition	(222,883)	(10,885)	(2,075)
Proceeds from sales of mineral interest and equipment	2,978	89,992	39,936
Distribution from Medusa Spar LLC	—	813	1,735
Net cash used in investing activities	(452,501)	(79,804)	(93,703)
Cash flows from financing activities:			
Borrowings on credit facility	132,500	80,000	53,000
Borrowings on term loan	382,500	—	—
Payments on credit facility	(119,500)	(68,000)	(43,000)
Payments on term loan	(84,149)	—	—
Payment of deferred financing costs	(19,779)	(146)	—
Redemption of 13% senior notes	(50,057)	(50,060)	(10,225)
Issuance of preferred stock	—	70,035	—
Issuance of common stock	122,450	—	—
Payment of preferred stock dividends	(7,895)	(4,627)	—
Taxes paid related to exercise of employee stock options	—	—	(18)
Net cash provided by (used in) financing activities	356,070	27,202	(243)
Net change in cash and cash equivalents	(2,044)	1,873	(42,656)
Balance, beginning of period	3,012	1,139	43,795
Balance, end of period	$ 968	$ 3,012	$ 1,139

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

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of business

Callon Petroleum Company is an independent oil and natural gas company established in 1950. The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company partially owned by a member of current management. As used herein, the “Company,” “Callon,” “we,” “us,” and “our” refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Callon is focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin in West Texas, and more specifically, the Midland Basin. The Company’s operations to date have been predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation. Callon has assembled a multi-year inventory of potential horizontal well locations and intends to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through acreage purchases, joint ventures and asset swaps.

Basis of presentation

Unless otherwise indicated, all dollar amounts included within the footnotes to the financial statements are presented in thousands, except for per share and per unit data.

The Consolidated Financial Statements include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company (“CPOC”). CPOC also includes the subsidiaries Callon Offshore Production, Inc. and Mississippi Marketing, Inc. All intercompany accounts and transactions have been eliminated. In the opinion of management, the accompanying audited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account and transaction eliminations, necessary to present fairly the Company’s financial position, the results of its operations and its cash flows for the periods indicated. Certain prior year amounts have been reclassified to conform to current year presentation.

Note 2 – Summary of Significant Accounting Policies

A. ***Use of Estimates***

The preparation of financial statements in conformity with United States generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

B. ***Cash and Cash Equivalents***

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

C. ***Accounts Receivable***

Accounts receivable consists primarily of accrued oil and natural gas production receivables and joint interest receivables from outside working interest owners.

D. ***Revenue Recognition and Natural Gas Balancing***

The Company recognizes revenue under the entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the Company’s net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the lower of cost or market. The revenue we receive from the sale of NGLs is included in natural gas sales. Natural gas balancing receivables and payables were immaterial as of December 31, 2014 and 2013.

E. ***Major Customers***

The Company's production is generally sold on month-to-month contracts at prevailing prices. The following table identifies customers to whom it sold greater than 10% of its total oil and natural gas production during each of the years ended:

	For the Year Ended December 31,		
	2014	**2013**	**2012**
Enterprise Crude Oil, LLC	51%	38%	32%
Plains Marketing, L.P.	22%	15%	15%
Sunoco	10%	0%	0%
Shell Trading Company	0%	31%	39%
Other	17%	16%	14%
Total	100%	100%	100%

Because alternative purchasers of oil and natural gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its ability to market future oil and natural gas production.

F. ***Oil and Natural Gas Properties***

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as oil and gas properties. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases, other costs related to exploration and development activities, and site restoration, dismantlement and abandonment costs capitalized in accordance with asset retirement obligation accounting guidance. Costs capitalized also include any internal costs that are directly related to exploration and development activities, including salaries and benefits, but do not include any costs related to production, general corporate overhead or similar activities. The Company capitalized $16,688, $14,753 and $13,331 of these internal costs during 2014, 2013 and 2012, respectively.

When applicable, proceeds from the sale or disposition of oil and natural gas properties are accounted for as a reduction to capitalized costs unless the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized in income.

Historical and estimated future development costs of oil and natural gas properties which have been evaluated and contain proved reserves, as well as the historical cost of properties which have been determined to have no future economic value, are depleted using the unit-of-production method based on proved reserves. Excluded from this amortization are costs associated with unevaluated properties, including capitalized interest on such costs. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or the Company determines that these costs have been impaired.

Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves,
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discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling amount). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. See Note 13 for additional information regarding the Company's oil and natural gas properties.

Upon the acquisition or discovery of oil and natural gas properties, the Company estimates the future net costs to dismantle, abandon and restore the property by using available geological, engineering and regulatory data. Such cost estimates are periodically updated for changes in conditions and requirements. In accordance with asset retirement obligation guidance, such costs are capitalized to the full cost pool when the related liabilities are incurred. In accordance with full cost accounting rules, assets recorded in connection with the recognition of an asset retirement obligation are included as part of the costs subject to the full cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations are excluded from the computation of the present value of estimated future net revenues used in determining the full cost ceiling amount.

G. ***Other Property and Equipment***

The Company depreciates its other property and equipment of $7,118 and $7,255 at December 31, 2014 and 2013, respectively, using the straight-line method over estimated useful lives of three to 20 years. Depreciation expense of $836, $750 and $760 relating to other property and equipment was included in general and administrative expenses in the Company's consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012, respectively. The accumulated depreciation on other property and equipment was $14,005 and $13,240 as of December 31, 2014 and 2013, respectively. The Company reviews its other property and equipment for impairment when indicators of impairment exist. See Note 14 for additional information.

H. ***Capitalized Interest***

The Company capitalizes interest on unevaluated oil and gas properties. Capitalized interest cannot exceed gross interest expense. During the years ended December 31, 2014, 2013 and 2012, the Company capitalized $4,295, $4,410 and $2,109 of interest expense.

I. ***Deferred Financing Costs***

Deferred financing costs are stated at cost, net of amortization, which is computed using the straight-line method over the life of the loan, which is reflective of the effective interest rate method. Deferred financing costs of $18,200 and $1,098 as of December 31, 2014 and 2013, respectively, net of accumulated amortization. Amortization of deferred financing costs of $1,272, $471 and $402 was recorded for the years ended December 31, 2014, 2013 and 2012, respectively.

J. ***Asset Retirement Obligations***

The Company is required to record its estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the consolidated statements of operations. See Note 12 for additional information.

K. ***Derivatives***

The Company's derivative contracts executed prior to 2012 were designated as cash flow hedges, and were recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity. Ineffective derivative contracts or ineffective portions of contracts designated as cash flow hedges were recognized as gain or loss on derivative contracts. The last of the Company's derivative contracts designated as cash flow hedges expired on December 31, 2012. Derivative contracts executed subsequent to December 31, 2012 and outstanding as of December 31, 2014 were not designated as accounting hedges, and are carried on the balance sheet at their fair market value. Changes in the fair value of derivative contracts not designated as accounting hedges are reflected in earnings as a gain or loss on derivative contracts. See Notes 6 and 7 for additional information regarding the Company's derivative contracts.

L. ***Income Taxes***

Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and natural gas properties for financial reporting purposes and income tax purposes. GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards, net of a valuation allowance. A valuation allowance is provided for that portion, if any, of the asset for which it is deemed more likely than not that it will not be realized. See Note 11 for additional information.

M. ***Share-Based Compensation***

The Company grants to directors and employees stock options and restricted stock awards ("RS awards"). The Company also grants restricted stock unit awards ("RSU awards") that may be settled in cash or common stock at the option of the Company and RSU awards that may only be settled in cash ("Cash-settleable RSU awards").

Stock Options. For stock options the Company expects to settle in common stock, share-based compensation expense is based on the grant-date fair value as calculated using the Black-Scholes option pricing model and recognized straight-line over the vesting period (generally three years).

RS awards, RSU awards and Cash-settleable RSU awards. For RS and RSU awards that the Company expects to settle in common stock, share-based compensation expense is based on the grant-date fair value and recognized straight-line over the vesting period (generally three years). For Cash-settleable RSU awards that the Company expects or is required to settle in cash, share-based compensation expense is based on the fair value remeasured at each reporting period as calculated using a Monte Carlo pricing model, because vesting of these awards is subject to a market condition, with the estimated value recognized over the vesting period (generally three years).

N. ***Statements of Cash Flows Supplemental Information***

During the three year period ended 2013, the Company paid no federal income taxes. During the years ended December 31, 2014, 2013 and 2012, the company made cash interest payments of $7,283, $13,189 and $13,920, respectively.

O. ***Investment in Medusa Spar LLC***

During the fourth quarter of 2013, the Company closed on the sale of its 15.0% working interest in the Medusa field, its 10.0% membership interest in Medusa Spar LLC ("LLC"), and substantially all of its remaining Gulf of Mexico shelf properties. Prior to the sale, the Company's ownership interest in the LLC was accounted for under the equity method of accounting. The LLC held a 75% undivided ownership interest in the deepwater spar production facilities at the Medusa field in the Gulf of Mexico and earned a tariff based upon production volume throughput from the Medusa area. The Company was obligated to process through the spar production facilities its share of production from the Medusa field and any future discoveries in the area. The balance of the LLC was owned by Oceaneering International, Inc. and Murphy Oil Corporation. See Note 3 for additional information on the Medusa divestiture.

P. ***Earnings per Share (EPS)***

The Company's basic EPS amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS, using the treasury-stock method, reflects the potential dilution caused by the exercise of all options and vesting of all restricted stock and restricted stock units settleable in shares.

Q. ***Recent Accounting Pronouncements***

In May 2014, the Financial Accounting Standards Board issued accounting standards update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. The guidance in ASU No. 2014-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

Note 3 – Acquisitions and Dispositions

2014 acquisitions

In the first quarter of 2014, the Company acquired 1,527 net acres in Upton and Reagan Counties, Texas, which are located in the southern portion of the Midland Basin near its existing core development fields, for an aggregate cash purchase price of $8,200. The properties bear a working interest of 100% and an average net revenue interest of 78%.

On October 8, 2014, the Company completed the acquisition of certain undeveloped acreage and producing oil and gas properties located in Midland, Andrews, Ector and Martin Counties, Texas (the "Central Midland Basin Acquisition") for an aggregate cash purchase price of $210,205, including estimated purchase price adjustments of $2,367 based on an effective date of May 1, 2014. The Company assumed operatorship of the properties on November 1, 2014, and acquired a 62% working interest (46.5% net revenue interest) in the Central Midland Basin Acquisition. The aggregate cash purchase price was funded with a combination of the net proceeds from an equity offering of $122,450 and a portion of the proceeds from borrowings under the Second Lien Loan. For additional information on the debt transactions and equity offering, see Notes 5 and 10, respectively.

The Central Midland Basin Acquisition was accounted for under the purchase method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The following purchase price allocation is based on management's estimates of the fair value of the assets acquired and liabilities assumed. The following table summarizes the acquisition date fair values of the net assets acquired:

Oil and natural gas properties	$	91,895
Unevaluated oil and natural gas properties		118,450
Asset retirement obligations		(140)
Net assets acquired	$	210,205

The following unaudited summary pro forma financial information for the year ended December 31, 2014 and 2013 has been presented for illustrative purposes only and does not purport to represent what the Company's results of operations would have been if the Central Midland Basin Acquisition had occurred as presented, or to project the Company's results of operations for any future periods. The pro forma financial information was prepared assuming the Central Midland Basin Acquisition and the debt transactions and equity offering discussed in Notes 5 and 10, respectively, occurred as of January 1, 2013. The pro forma adjustments are based on available information and certain assumptions that management believes are reasonable, including revenue, lease operating expenses, production taxes, depreciation, depletion and amortization expense, accretion expense, interest expense and capitalized interest.

	For the Years Ended December 31,			
	2014		2013	
Revenues	$	180,458	$	151,766
Income from operations		53,526		36,002
Income available to common stockholders		33,674		4,033
Net income per common share				
Basic	$	0.57	$	0.07
Diluted	$	0.56	$	0.07

2013 acquisitions

During the second quarter of 2013, the Company acquired approximately 2,468 gross (2,186 net) acres in Reagan and Upton Counties, Texas, which is located in the Southern Midland Basin and which is prospective for both horizontal and vertical drilling. The acquisition also included seven gross vertical wells and 1,301 barrels of oil equivalent proved reserves. The purchase price of $11,000 was funded using a portion of the proceeds from the preferred stock offering (discussed in Note 10).

2012 acquisitions

During the first quarter of 2012, the Company acquired 16,233 gross (14,653 net) acres in Borden County, which is located in the Northern Midland basin. The Northern Midland basin has had limited drilling activity compared with the Southern Midland basin (where our current production is located), increasing the economic risk related to these drilling activities. The purchase price of $14,538 was funded from existing cash balances. During the third quarter of 2012, we acquired an additional 8,095 gross acres (6,964 net) in this area for a total consideration of $4,835.

During the second quarter of 2012, the Company signed a purchase and sale agreement to acquire 2,319 gross (1,762 net) acres in southern Reagan County, Texas for a total purchase price of $12,012, which was financed with a draw on the Credit Facility. The transaction had an effective date of May 1, 2012 and closed on July 5, 2012.

2013 dispositions

During the fourth quarter of 2013, the Company closed on the sale of its 15.0% working interest in the Medusa field (Mississippi Canyon blocks 582 and 538), our 10.0% membership interest in Medusa Spar LLC, and substantially all of our remaining Gulf of Mexico shelf properties for total net cash consideration of approximately $88,000 after customary purchase price adjustments. Also during the fourth quarter of 2013, the Company closed on the sale of its 69% interest in the Swan Lake field for $2,000. This was the Company's only field in the Haynesville shale. The proceeds from these sales were accounted for as a reduction to capitalized costs as the sales did not significantly alter the relationship between capitalized costs and proved reserves.

2012 dispositions

During 2012, the Company closed on the sale of its 11.25% working interest in the Habanero field (Garden Banks Block 341) for net cash consideration of $39,410 after customary purchase price adjustments. The proceeds from this sale were accounted for as a reduction to capitalized costs as the sale did not significantly alter the relationship between capitalized costs and proved reserves.

Note 4 - Earnings Per Share

Basic earnings (loss) per share is computed by dividing income (loss) available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of non-vested restricted shares and unexercised options outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. A reconciliation of the basic and diluted net income per share computation is as follows:

The following table sets forth the computation of basic and diluted earnings per share:

	For the Year Ended December 31,		
	2014	2013	2012
Net income (loss)	$ 37,766	$ 4,304	$ 2,747
Preferred stock dividends	(7,895)	(4,627)	—
Income (loss) available to common stockholders	$ 29,871	$ (323)	$ 2,747
Weighted average shares outstanding	44,848	40,133	39,522
Dilutive impact of stock options	—	—	8
Dilutive impact of restricted stock	1,113	—	807
Weighted average shares outstanding for diluted income (loss) per share (a)	45,961	40,133	40,337
Basic income (loss) per share	$ 0.67	$ (0.01)	$ 0.07
Diluted income (loss) per share	$ 0.65	$ (0.01)	$ 0.07
The following were excluded from the diluted earnings per share calculation because their effect would be anti-dilutive:			
Stock options	30	52	52
Restricted stock	317	398	123

(a) Because the Company reported a loss available to common stockholders for the year ended December 31, 2013, no unvested stock awards were included in computing loss per share because the effect was anti-dilutive.

Note 5 – Borrowings

The Company's borrowings consisted of the following at:

	For the Year Ended December 31,	
	2014	2013
Principal components:		
Senior secured revolving credit facility	$ 35,000	$ 22,000
Secured second lien term loan	300,000	—
13% Senior Notes, principal	—	48,481
Total principal outstanding	335,000	70,481
13% Senior Notes, unamortized deferred credit	—	5,267
Total carrying value of borrowings	$ 335,000	$ 75,748

Senior secured revolving credit facility (the "Credit Facility")

On March 11, 2014, the Company entered into the Fifth Amended and Restated Credit Agreement to the Credit Facility with a maturity date of March 11, 2019. JPMorgan Chase Bank, N.A. is Administrative Agent, and participating lenders include Regions Bank, Citibank, N.A., Capital One, N.A., KeyBank, N.A., Whitney Bank, IberiaBank, N.A., OneWest Bank, N.A., SunTrust Bank and Royal Bank of Canada. The total notional amount available under the Credit Facility is $500,000. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. In conjunction with the closing of the Acquisition on October 8, 2014, the borrowing base on the Company's Credit Facility was amended to $250,000.

As of December 31, 2014, the balance outstanding on the Credit Facility was $35,000 with a weighted-average interest rate of 1.91%, calculated as the LIBOR plus a tiered rate ranging from 1.75% to 2.75%, which is determined based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the borrowing base. The Company had $215,000 of available borrowings under the Credit Facility as of December 31, 2014.

Term loans

On March 11, 2014, the Company entered into a term loan in an aggregate amount of up to $125,000, including initial commitments of $100,000 and additional availability of $25,000 subject to the consent of two-thirds of the lenders and compliance with financial covenants after giving effect to such increase. The term loan had a maturity date of September 11, 2019, and was not subject to mandatory prepayments unless new debt or preferred stock was issued. It was prepayable at the Company's option, subject to a prepayment premium. The prepayment amount was (i) 102% if the prepayment event occurs prior to March 11, 2015, and (ii) 101% if the prepayment event occurs on or after March 15, 2015 but before March 15, 2016, and (iii) 100% for prepayments made on or after March 15, 2016. The term loan was secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement. On April 10, 2014, the Company drew an initial amount of $62,500 with an original issue discount of 1.0%.

On October 8, 2014, the term loan described above was repaid in full using proceeds from a new secured second lien term loan (the "Second Lien Loan") in conjunction with the closing of the Acquisition, resulting in a loss on early extinguishment of debt of $3,054. The Second Lien Loan has a maturity date of October 8, 2021. On October 8, 2014, the Company drew an initial amount of $300,000 with a discount of 2.0% and an interest rate of 8.5%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.5% per annum. The Second Lien Loan may be prepaid at the Company's option, subject to a prepayment premium. The prepayment amount is (i) 102% if the prepayment event occurs prior to October 8, 2015, and (ii) 101% if the prepayment event occurs on or after October 8, 2015 but before October 8, 2016, and (iii) 100% for prepayments made on or after October 8, 2016. The Second Lien Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement. The Royal Bank of Canada is Administrative Agent, and participants include several institutional lenders.

13% senior notes due 2016 (“Senior Notes”) and deferred credit

On April 11, 2014, the Company completed a full redemption of the remaining $48,481 principal amount of outstanding Senior Notes using proceeds from the Second Lien Loan. The redemption resulted in a net $3,205 gain on the early extinguishment of debt (including $4,780 of accelerated deferred credit amortization). The gain represents the difference between the $50,057 paid for the redemption of the Senior Notes ($1,576 of redemption costs, primarily the call premium) and the carrying value of the remaining Senior Notes of $53,261 (inclusive of $4,780 of deferred credit). The Company also paid $193 in accrued interest through the redemption date. Upon the redemption, the indenture governing the Senior Notes was discharged in accordance with its terms.

Using a portion of the proceeds from the sale of our interest in Medusa on December 17, 2013, the Company redeemed $48,481 of its Senior Notes, which resulted in a net $3,696 gain on the early extinguishment of debt. The gain represents the difference between the $50,057 paid for the redemption of the Senior Notes (inclusive of $1,576 of redemption expenses, primarily the call premium) and the carrying value of $53,756 (inclusive of the $5,275 of accelerated deferred credit amortization).

In June 2012, the Company redeemed $10,000 of its Senior Notes, which resulted in a net $1,366 gain on the early extinguishment of debt. The gain represents the difference between the $10,225 paid for the redemption of the Senior Notes (inclusive of $225 of redemption expenses, primarily the call premium) and the carrying value of $11,591 (inclusive of the $1,591 of accelerated deferred credit amortization).

Restrictive covenants

The Company’s Credit Facility and Second Lien Loan contain various covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2014.

Note 6 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil and natural gas prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil and natural gas production. The Company utilizes a mix of

collars, swaps, puts, calls and similar derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative instruments exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties’ creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument; see Note 7 for additional information regarding fair value.

The Company executes commodity derivative contracts under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

Financial statement presentation and settlements

Settlements of the Company’s derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a benchmark price, such as the NYMEX price. To determine the fair value of the Company’s derivative instruments, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See Note 7 for additional information regarding fair value.

Derivatives not designated as hedging instruments

The Company elected not to designate its derivative contracts as accounting hedges for contracts executed subsequent to December 31, 2012. Consequently, the Company records its derivative contracts at fair value in the consolidated balance sheet and records changes in fair value as a gain or loss on derivative contracts in the consolidated statement of operations. Cash settlements are also recorded as gain or loss on derivative contracts in the consolidated statement of operations.

The following table reflects the fair value of the Company’s derivative instruments for the periods presented:

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	**Classification**	**Line Description**	**12/31/2014**	**12/31/2013**	**12/31/2014**	**12/31/2013**	**12/31/2014**	**12/31/2013**
Derivatives not designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair value of derivatives	$ 1,262	$ 60	$ (7)	$ —	$ 1,255	$ 60
Natural gas	Non-current	Other long-term liabilities	—	—	—	(72)	—	(72)
Oil	Current	Fair value of derivatives	26,588	—	(1,242)	(1,036)	25,346	(1,036)
	Total		$ 27,850	$ 60	$ (1,249)	$ (1,108)	$ 26,601	$ (1,048)

As previously discussed, the Company’s derivative contracts are subject to master netting arrangements. The Company’s policy is to present the fair value of derivative contracts on a net basis in the consolidated balance sheet. The following presents the impact of this presentation to the Company’s recognized assets and liabilities for the periods indicated:

	For the Year Ended December 31, 2014		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
Current assets: Fair value of derivatives	$ 27,850	$ —	$ 27,850
Current liabilities: Fair value of derivatives	$ (1,249)	$ —	$ (1,249)

	For the Year Ended December 31, 2013		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
Current assets: Fair value of derivatives	$ 8	$ 52	$ 60
Current liabilities: Fair value of derivatives	1,088	(52)	1,036
Long-term liabilities: Fair value of derivatives	$ (72)	$ —	$ (72)

Derivatives not designated as hedging instruments under ASC 815

For the periods indicated, the Company recorded the following related to its derivatives in the consolidated statement of operations as gain or loss on derivative contracts:

	For the Year Ended December 31,		
	2014	2013	2012
Natural gas derivatives			
Net gain (loss) on settlements	$ (84)	$ (148)	$ 34
Net gain (loss) on fair value adjustments	1,267	230	(241)
Total gain (loss)	$ 1,183	$ 82	$ (207)
Oil derivatives			
Net gain (loss) on settlements	$ 4,170	$ 1,518	$ —
Net gain (loss) on fair value adjustments	26,383	(2,960)	1,924
Total gain (loss)	$ 30,553	$ (1,442)	$ 1,924
Total gain (loss) on derivative contracts	$ 31,736	$ (1,360)	$ 1,717

Derivatives designated as hedging instruments under ASC 815

The Company's derivative contracts executed prior to December 31, 2012 were designated as accounting hedges. The table below presents the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase to oil and natural gas sales:

	For the Year Ended December 31,		
	2014	2013	2012
Amount of gain reclassified from OCI into income	$ —	$ —	$ 1,420

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of December 31, 2014:

	For the Three Months Ended			
Oil contracts	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Collar contracts combined with short puts (three-way collar):				
Volume (MBbls)	158	159	—	—
Price per Bbl				
Ceiling (short call)	$ 99.10	$ 99.10	$ —	$ —
Floor (long put)	$ 90.00	$ 90.00	$ —	$ —
Short put	$ 75.00	$ 75.00	$ —	$ —
Swap contracts:				
Total volume (MBbls)	171	136	129	74
Weighted average price per Bbl	$ 92.25	$ 92.18	$ 92.25	$ 92.20
Put spreads:				
Volume (MBbls)	—	—	138	138
Long put price per Bbl	$ —	$ —	$ 90.00	$ 90.00
Short put price per Bbl	$ —	$ —	$ 75.00	$ 75.00

Natural gas contracts	For the Three Months Ended March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Collar contracts combined with short puts (three-way collar):				
Volume (BBtu)	248	227	207	161
Weighted average price per MMBtu				
Ceiling (short call)	$ 4.67	$ 4.32	$ 4.32	$ 4.32
Floor (long put)	$ 4.00	$ 3.85	$ 3.85	$ 3.85
Short put	$ 3.50	$ 3.25	$ 3.25	$ 3.25
Swap contracts:				
Total volume (BBtu)	271	237	219	228
Weighted average price per MMBtu	$ 3.98	$ 3.98	$ 3.98	$ 3.96
Short call contract:				
Short call volume (BBtu)	108	109	110	111
Short call price per MMBtu	$ 5.00	$ 5.00	$ 5.00	$ 5.00

Subsequent to December 31, 2014, the Company restructured its portfolio of benchmark West Texas Intermediate oil hedges for 2015 and separately entered into new swap arrangements. The Company converted all of its three-way collars and put spreads into new swap contracts with fixed swap prices that received a premium to prevailing swap price levels at the time to reflect the value of the monetized put spreads embedded in the converted non-swap structures. Following the restructuring transaction and addition of new swap contracts, we currently have an average of 4,165 barrels of oil per day hedged at a weighted average swap price of $70.89 per barrel for calendar year 2015.

In addition, the Company recently entered into basis differential swaps that provide for a fixed price spread between the Midland and NYMEX prices for West Texas Intermediate oil. The Company hedged an average of approximately 4,120 barrels of oil per day from March 2015 to December 2015 at a weighted average Midland swap spread of ($2.39) per barrel.

The following derivative contracts for oil were executed subsequent to December 31, 2014:

Oil contracts	For the Three Months Ended March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Swap contracts:				
Total volume (MBbls)	231	273	253	253
Weighted average price per Bbl	$ 60.77	$ 60.09	$ 59.83	$ 59.83
Swap contracts (Differentials):				
Total volume (MBbls)	152	400	382	326
Weighted average price per Bbl	$ (2.41)	$ (2.40)	$ (2.39)	$ (2.38)

Note 7 - Fair Value Measurements

The fair value hierarchy outlined in the relevant accounting guidance gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable, and these valuations have the lowest priority.

Fair Value of Financial Instruments

Cash, cash equivalents, restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The Company’s debt is recorded at the carrying amount in the consolidated balance sheet. The carrying amount of floating-rate debt approximated fair value because the interest rates were variable and reflective of market rates.

The following table summarizes the respective carrying and fair values at:

	December 31,			
	2014		2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 35,000	$ 35,000	$ 22,000	$ 22,000
Second Lien Loan	300,000	300,000	—	—
13% Senior Notes due 2016 (a)	—	—	53,748	50,299
Total	$ 335,000	$ 335,000	$ 75,748	$ 72,299

(a) The fair value, using Level 2 inputs, was based upon estimates provided by an independent investment banking firm. 2013 fair value was determined only in relation to the $48,481 face value outstanding of the 13% Senior Notes. The remaining $5,267 represented the deferred credit, which was excluded from the fair value calculation. See Note 5 for additional information.

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis in the consolidated balance sheet. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using an income approach valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. The Company believes that the majority of the inputs used to calculate the commodity derivative instruments fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 6 for additional information regarding the Company's derivative instruments.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis:

December 31, 2014	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ 27,850	$ —	$ 27,850
Derivative financial instruments (non-current)	Other assets, net	—	—	—	—
Sub-total assets		$ —	$ 27,850	$ —	$ 27,850
Liabilities					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ (1,249)	$ —	$ (1,249)
Derivative financial instruments (non-current)	Other long-term liabilities	—	—	—	—
Sub-total liabilities		$ —	$ (1,249)	$ —	$ (1,249)
Total net assets (liabilities)		$ —	$ 26,601	$ —	$ 26,601

December 31, 2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ 60	$ —	$ 60
Derivative financial instruments (non-current)	Other assets, net	—	—	—	—
Sub-total assets		$ —	$ 60	$ —	$ 60
Liabilities					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ (1,036)	$ —	$ (1,036)
Derivative financial instruments (non-current)	Other long-term liabilities	—	(72)	—	(72)
Sub-total liabilities		$ —	$ (1,108)	$ —	$ (1,108)
Total net assets (liabilities)		$ —	$ (1,048)	$ —	$ (1,048)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Acquisition. On October 8, 2014, the Company completed the Acquisition as discussed in Note 3. The Company determined the fair value of the assets acquired using the income approach based on expected future cash flows from estimated reserve quantities; costs to produce and develop reserves; and oil and gas forward prices. Asset retirement obligations assumed in connection with the Central Midland Basin Acquisition were determined in accordance with applicable accounting standards. The fair value measurements were based on level 2 and level 3 inputs. For more information on the Acquisition see Note 3.

During the second quarter of 2013, the Company completed an acquisition as discussed in Note 3. The Company determined the fair value of the assets acquired using the income approach based on expected future cash flows from estimated reserve quantities; costs to produce and develop reserves; and oil and gas forward prices. Asset retirement obligations assumed in connection with this acquisition were determined in accordance with applicable accounting standards. The fair value measurements were based on level 2 and level 3 inputs.

Other Property and Equipment. As discussed in Note 14, the Company's decision to abandon certain of its other property and equipment, that had been classified as held for sale, resulted in an impairment charge of $1,707 which is included in the Company's Statement of Operations for the year ended December 31, 2013. The impairment charge was valued using level 3 inputs. See Note 14 for more information.

Note 8 – Employee Benefit Plans

The Company utilizes various forms of incentive compensation designed to align the interest of the executives and employees with those of its stockholders. Tabular disclosures related to the share-based awards are presented in Note 9. The narrative that follows provides a brief description of each plan, summarizes the overall status of each plan and discusses current year awards under each plan:

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Savings and Protection Plan

The Savings and Protection Plan ("401-K Plan") provides employees with the option to defer receipt of a portion of their compensation, and the Company may, at its discretion, match a portion of the employee's deferral with cash. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the 401-K Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the 401-K Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $1,017, $923 and $918 in the years 2014, 2013 and 2012, respectively.

2011 Omnibus Incentive Plan (the "2011 Plan")

The 2011 Plan, which became effective May 12, 2011 following shareholder approval, authorized and reserved for issuance 2,300,000 shares of common stock, which may be issued upon exercise of vested stock options and/or the vesting of any other share-based equity award that is granted under this plan. The 2011 Plan is the Company's only active plan, and included a provision at inception whereby all remaining, un-issued and authorized shares from the Company's previous share-based incentive plans became issuable under the 2011 Plan. This transfer provision resulted in the transfer of an additional 841,000 shares into the plan, increasing the quantity authorized and reserved for issuance under the 2011 Plan to 3,141,000 at the inception of the plan. Another provision provided that shares which would otherwise become available for issue under the previous plans as a result of vesting and/or forfeiture of any equity awards existing as of May 12, 2012, would also increase the authorized shares available to the 2011 Plan. As of December 31, 2014, the 2011 Plan had 1,132,000 shares remaining and eligible for future issuance.

Equity awards issued under this plan may be subject to various vesting, accelerated vesting, and forfeiture provisions upon the occurrence of certain events. Any vested but unexercised options contractually expire 10 years from the date of grant. Equity awards under the 2011 Plan generally vest over time but may also be subject to attaining a specified performance metrics and may vest immediately or cliff vest at a specified date. The Company will recognize expense on the grant date for all immediately vesting awards, while it will recognize expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis. For market-based awards, the Company recognizes expense based on its analysis of the market criteria, and records expense as necessary based on its analysis. Awards with a market-based provision do not allow for the reversal of previously recognized expense, even if the market metric is not achieved and no shares ultimately vest or are awarded.

Cash-Settled RSU Awards

Certain of the Company's RSUs awarded require cash settlement. Cash-settled RSU awards are accounted for as liabilities as the Company is contractually obligated to settle these awards in cash. The fair value of the Company's market-based RSU awards is calculated using a Monte Carlo valuation model, which considers such inputs as the Company's and its peer group's stock prices, a risk-free interest rate, and an estimated volatility for the Company and its peer group. Changes in the fair value of cash-settleable awards are recorded as adjustments to compensation expense.

Market-based RSUs: A significant portion of the Company's cash-settled RSU awards include a market-based vesting condition that determines the actual number of units that will ultimately vest. The number of RSUs that vest is based on a calculation that compares the Company's total shareholder return to the same calculated return of a group of peer companies as selected by the Company, and the number of units that will vest can range between 0% and 200% of the base units awarded.

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As of December 31, 2014, the Company had the following cash-settleable RSU awards outstanding (including those that are not based on a market condition):

(shares in 000s)	Base Units Outstanding	Potential Minimum Units Vesting	Potential Maximum Units Vesting
Vesting in 2015	837	52	1,622
Vesting in 2016	416	60	772
Vesting in 2017	24	24	24
Other	137	137	137
Total cash-settleable RSU awards	1,414	273	2,555

For the year ended December 31, 2014, 523,000 market-based cash-settled RSUs subject to the peer market-based vesting described above vested at between 150% - 200%, depending on the date of vesting, resulting in cash payments of $1,241 in 2014 and payable amounts of $3,599 in 2015. Also during 2014, 58,000 non-market-based cash settled RSUs vested, resulting in cash payments of $559 in 2014. During 2013, 260,000 market-based cash-settled RSUs subject to the peer market-based vesting described above vested at 100% of their issued units, resulting in cash payments of $1,669 in 2014. Also during 2013, 65,000 non-market-based cash settled RSUs vested, resulting in cash payments of $239 in 2013. See Note 9 for additional information regarding cash-settleable RSUs.

Note 9 - Share-Based Compensation

As discussed in Note 8, the Company grants various forms of share-based compensation awards to employees of the Company and its subsidiaries and to non-employee members of the Board of Directors. At December 31, 2014, shares available for future share-based awards, including stock options or restricted stock grants, under the Company's only active plan, the 2011 Plan, were 1,132,000.

The following table presents share-based compensation expense for each respective period:

	For the Year Ended December 31,					
	2014		2013		2012	
Share-based compensation cost for:	Equity-based	Liability-based	Equity-based	Liability-based	Equity-based	Liability-based
RSU equity awards	$ 4,223	$ —	$ 3,975	$ —	$ 4,210	$ —
Cash-settleable RSU awards	—	6,918	—	5,347	—	2,916
401(k) contributions in shares	270	—	219	—	218	—
Total share-based compensation cost (a)	$ 4,493	$ 6,918	$ 4,194	$ 5,347	$ 4,428	$ 2,916

(a) The portion of this share-based compensation cost that was included in general and administrative expense totaled $7,235, $5,751 and $4,081 for the same years, respectively, and the portion capitalized to oil and gas properties was $4,176, $3,791 and $3,263, respectively.

The following table presents the unrecognized compensation cost for the indicated periods:

	For the Year Ended December 31,		
Unrecognized compensation cost related to:	**2014**	**2013**	**2012**
Unvested RSU equity awards	$ 3,979	$ 5,331	$ 6,320
Unvested cash-settleable RSU awards	4,977	7,669	2,826

The Company's unrecognized compensation cost related to unvested RSU and cash-settleable RSU awards is expected to be recognized over a weighted-average period of 1.6 years.

The following table summarizes the Company's liability for cash-settled RSU awards for the periods indicated:

	December 31,	
Consolidated Balance Sheets Classification	**2014**	**2013**
Cash-settled restricted stock unit awards - current	$ 3,856	$ 4,173
Cash-settled restricted stock unit awards - non-current	7,175	3,409
Total cash-settled RSU awards	$ 11,031	$ 7,582

Stock Options

The Company issued no stock options for the past three years and had no options vest or forfeit during 2014. Additionally, no options were exercised, and 22,000 options expired unexercised during the year. As of December 31, 2014, the Company had 30,000 options outstanding and exercisable at a weighted average exercise price per option of $14.04, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 1.3 years.

As of December 31, 2013, the Company had 52,000 options outstanding and exercisable at a weighted average exercise price per option of $13.75, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 2.3 years. As of December 31, 2012, the Company had 67,000 options outstanding and exercisable at a weighted average exercise price per option of $11.82, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 2.7 years.

Restricted Stock Units

The following table represents unvested restricted stock activity for the year ended December 31, 2014:

(shares in 000s)	Number of Shares	Weighted average Grant-Date Fair Value per Share	Weighted average Period over which expense is expected to be recognized
Outstanding at the beginning of the period	2,262	$ 5.03	
Granted	333	9.67	
Vested (a)	(684)	6.34	
Forfeited	(43)	4.11	
Outstanding at the end of the period	1,868	$ 5.40	1.2

(a) The fair value of shares vested was $4,338.

For the year ended December 31, 2013, the Company granted 944,000 RSUs with a weighted average grant-date fair value of $3.82 per share. The fair value of shares vested during 2013 was $2,689. For the year ended December 31, 2012, the Company granted 1,008,000 RSUs with a weighted average grant-date fair value of $5.22 per share. The fair value of shares vested during 2012 was $2,817.

Note 10 – Equity Transactions

10% Series A Cumulative Preferred Stock ("Preferred Stock")

Holders of the Company's Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10.0% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends are payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by our Board of Directors. Preferred Stock dividends were $7,895 and $4,627 in 2014 and 2013, respectively.

The Preferred Stock has no stated maturity and is not be subject to any sinking fund or other mandatory redemption. On or after May 30, 2018, the Company may, at its option, redeem the Preferred Stock, in whole or in part, by paying $50.00 per share, plus any accrued and unpaid dividends to the redemption date.

Following a change of control, the Company will have the option to redeem the Preferred Stock, in whole but not in part for $50.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), to the redemption date. If the Company does not exercise its option to redeem the Preferred Stock upon a change of control, the holders of the Preferred Stock have the option to convert the Preferred Stock into a number of shares of the Company's common stock based on the value of the common stock on the date of the change of control as determined under the certificate of designations for the Preferred Stock. If the change of control occurred on December 31, 2014, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of the common stock on such date ($5.45) as the value of a share of common stock, each share of Preferred Stock would be convertible
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into approximately 9.2 shares of common stock. If the Company exercises its redemption rights relating to shares of Preferred Stock, the holders of Preferred Stock will not have the conversion right described above.

Common Stock

On September 15, 2014 the Company completed an underwritten public offering of 12,500,000 shares of its common stock at $9.00 per share, before underwriting discounts, and the exercise in full by the underwriters of their option to purchase 1,875,000 additional shares of common stock at $9.00 per share. The Company received net proceeds of approximately $122,450, after the underwriting discounts and estimated offering costs, which were used to fund a portion of the purchase price of the Acquisition (see Note 3).

Note 11 - Income Taxes

The Company provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses and state income taxes. The effective tax rate for the years ended December 31, 2014 and 2013 was 38% and 42%, respectively.

The following table presents Callon's deferred tax assets and liabilities with respect to its carryforwards and other temporary differences:

	As of December 31,	
	2014	**2013**
Deferred tax asset		
Federal net operating loss carryforward	$ 86,629	$ 70,365
Statutory depletion carryforward	8,876	8,880
Alternative minimum tax credit carryforward	208	208
Asset retirement obligations	1,003	1,024
Other	6,621	7,575
Total deferred tax asset	103,337	88,052
Deferred tax liability		
Oil and natural gas properties	54,723	26,412
Other	10,140	32
Total deferred tax liability	64,863	26,444
Net deferred tax asset	$ 38,474	$ 61,608

If not utilized, the Company's federal operating loss ("NOL") carryforwards will expire as follows:

		Year Expiring				
	Total	**2015-2020**	**2021-2023**	**2024-2026**	**2027-2029**	**2030-2034**
Federal NOL carryforwards	$ 247,513	$ —	$ 111,415	$ 14,408	$ 41,379	$ 80,311

The Company's current operations are located in Texas and are subject to the Texas margin tax. The Company has established a full valuation allowance on the tax benefits associated with state net operating loss carryforwards of approximately $171,907, which expire in years through 2034, related to other states in which the Company does not anticipate generating taxable state income. These amounts are not included in the deferred tax summary table above.

The Company had no significant unrecognized tax benefits at December 31, 2014. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. Tax periods for years 2001 through 2014 remain open to examination by the federal and state taxing jurisdictions to which the Company is subject.

Below is a reconciliation of the reported amount of income tax expense attributable to continuing operations to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations.

	For the Year Ended December 31,		
Components of income tax rate reconciliation	**2014**	**2013**	**2012**
Income tax expense computed at the statutory federal income tax rate	35%	35%	35%
Percentage depletion carryforward	—%	(8)%	(22)%
State taxes net of federal benefit	1%	4%	6%
Restricted stock and stock options	—%	5%	2%
Section 162(m)	2%	6%	22%
Other	—%	—%	4%
Effective income tax rate	38%	42%	47%

Components of income tax expense	For the Year Ended December 31, 2014	2013	2012
Current state income tax expense	$ —	$ 326	$ 110
Deferred federal income tax expense	22,373	2,652	1,777
Deferred state income tax expense	761	126	336
Total income tax expense	$ 23,134	$ 3,104	$ 2,223

Note 12 - Asset Retirement Obligations

The table below summarizes the activity for the Company's asset retirement obligations:

	For the Year Ended December 31, 2014	2013
Asset retirement obligations at January 1, 2014	$ 6,732	$ 13,301
Accretion expense	826	1,785
Liabilities incurred	638	679
Liabilities assumed	140	—
Liabilities settled	(2,130)	(457)
Liabilities related to oil and gas properties sold	—	(4,765)
Revisions to estimate	468	(3,811)
Asset retirement obligations at end of period	6,674	6,732
Less: Current asset retirement obligations	(4,747)	(4,120)
Long-term asset retirement obligations at December 31, 2014	$ 1,927	$ 2,612

Certain of the Company's operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the Consolidated Balance Sheets at December 31, 2014 as long-term restricted investments were $3,810. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 13 – Supplemental Information on Oil and Natural Gas Properties (Unaudited)

The following table discloses certain financial data relating to the Company's oil and natural gas activities, all of which are located in the United States.

	For the Year Ended December 31, 2014	2013	2012
Evaluated Properties			
Beginning of period balance	$ 1,701,577	$ 1,497,010	$ 1,421,640
Capitalized G&A	10,071	10,014	12,148
Property acquisition costs (a)	94,541	10,885	2,075
Exploration costs	118,251	147,164	22,703
Development costs	153,545	36,504	38,444
End of period balance	$ 2,077,985	$ 1,701,577	$ 1,497,010
Unevaluated Properties			
Beginning of period balance	$ 43,222	$ 68,776	$ 2,603
Property acquisition costs (a)	128,342	2,259	29,590
Exploration costs	11,177	10,767	34,674
Capitalized interest	4,295	4,410	2,109
Transfers to evaluated	(44,511)	(42,990)	(200)
End of period balance	$ 142,525	$ 43,222	$ 68,776
Accumulated depreciation, depletion and amortization			
Beginning of period balance	$ 1,420,612	$ 1,296,265	$ 1,208,331
Provision charged to expense	56,663	42,251	48,524
Sale of mineral interests	1,080	82,096	39,410
End of period balance	$ 1,478,355	$ 1,420,612	$ 1,296,265

(a) For more information on acquisitions refer to Note 3

Unevaluated property costs primarily include lease acquisition costs, unevaluated drilling costs, seismic, capitalized interest and certain overhead costs related to exploration and development. These costs are directly related to the acquisition and evaluation of unproved properties. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The Company expects that the majority of these costs will be evaluated over the next three but within five years.

Subsequent to December 31, 2014 and through February 27, 2015, the Company completed five horizontal wells, drilled four horizontal wells and had two horizontal wells in progress.

Depletion per unit-of-production, on a BOE basis, amounted to $27.51, $31.12 and $31.56 for the years ended December 31, 2014, 2013, and 2012, respectively. Lease operating expenses per unit-of-production, on a BOE basis, amounted to $10.85, $14.00, and $14.81 for the years ended December 31, 2014, 2013, and 2012, respectively.

Under the full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling amount). These rules generally require pricing based on the preceding 12-months' average oil and natural gas market prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. Given the volatility of oil and natural gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices remain at current levels or decline further, even if only for a short period of time, write-downs of oil and natural gas properties could occur in the future.

Estimated Reserves

The Company's proved oil and natural gas reserves at December 31, 2014 have been estimated by DeGolyer and MacNaughton, the Company's current independent petroleum engineers. The Company's proved oil and natural gas reserves at December 31, 2013 and 2012 were estimated by Huddleston & Co., Inc. The reserves were prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only, and should not be deemed exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and natural gas properties or the cost that would be incurred to obtain equivalent reserves.

Changes in the estimated net quantities of oil and natural gas reserves, all of which are located onshore within the continental United States and offshore within the Gulf of Mexico (prior to December 31, 2013), are as follows:

	Reserve Quantities For the Year Ended December 31,		
	2014	2013	2012
Proved developed and undeveloped reserves:			
Oil (MBbls):			
Beginning of period	11,898	10,780	10,075
Revisions to previous estimates	(243)	(2,540)	(488)
Purchase of reserves in place	3,223	150	38
Sale of reserves in place	-	(3,294)	(504)
Extensions and discoveries	12,547	7,713	2,636
Production	(1,692)	(911)	(977)
End of period	25,733	11,898	10,780
Natural Gas (MMcf):			
Beginning of period	17,751	19,753	35,118
Revisions to previous estimates	(215)	(5,351)	(10,838)
Purchase of reserves in place	8,591	317	115
Sale of reserves in place	-	(4,576)	(4,404)
Extensions and discoveries	18,641	10,619	3,350
Production	(2,220)	(3,011)	(3,588)
End of period	42,548	17,751	19,753
Proved developed reserves:			
Oil (MBbls):			
Beginning of period	5,960	4,955	5,069
End of period	14,006	5,960	4,955
Natural gas (MMcf):			
Beginning of period	9,059	10,680	11,605
End of period	25,171	9,059	10,680
MBOE:			
Beginning of period	7,470	6,735	7,003
End of period	18,201	7,470	6,735
Proved undeveloped reserves:			
Oil (MBbls):			
Beginning of period	5,938	5,825	5,006
End of period	11,727	5,938	5,825
Natural gas (MMcf):			
Beginning of period	8,692	9,073	23,513
End of period	17,377	8,692	9,073
MBOE:			
Beginning of period	7,387	7,337	8,925
End of period	14,623	7,387	7,337

Total Proved Reserves: The Company ended 2014 with estimated net proved reserves of 32,824 MBOE, representing a 121% increase over 2013 year-end estimated net proved reserves of 14,857 MBOE. The increase was primarily due the Company’s development of its properties in the Permian Basin, on which it drilled a total of 34 gross (28.7 net) wells, and acquisitions made during 2014. This increase was primarily offset by 2014 production and revisions.

The Company ended 2013 with estimated net proved reserves of 14,857 MBOE, representing a 6% increase over 2012 year-end estimated net proved reserves of 14,072 MBOE. The increase was primarily due the Company’s development of its properties in the Permian Basin offset by the sale of the Company’s interest in the Medusa field and due to the Company’s reclassification of certain vertical PUD locations to the horizontal probable and PUD categories.

The Company ended 2012 with estimated net proved reserves of 14,072 MBOE, representing a 12% decrease over 2011 year-end estimated net proved reserves of 15,928 MBOE. The decrease was primarily due to the sale of the Company's interest in the Habanero field and the downward revision of our Haynesville Shale undeveloped reserves at year-end 2012, which were reduced due to low natural gas prices. These decreases were partially offset by the Company's development of a portion of its Permian Basin, on which it drilled a total of 27 oil wells during 2012.

Extrapolation of performance history and material balance estimates were utilized by the Company's independent petroleum and geological firm to project future recoverable reserves for the producing properties where sufficient history existed to suggest performance trends and where these methods were applicable to the subject reservoirs. The projections for the remaining producing properties were necessarily based on volumetric calculations and/or analogy to nearby producing completions. Reserves assigned to nonproducing zones and undeveloped locations were projected on the basis of volumetric calculations and analogy to nearby production, and to a small extent, horizontal PDP and PUD categories.

Proved Undeveloped Reserves: The Company annually reviews its proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. Generally, reserves for the Company's onshore properties are booked as PUDs only if the Company has plans to convert the PUDs into proved developed reserves within five years of the date they are first booked as PUDs. The Company's PUDs increased 98% to 14,623 MBOE from 7,387 MBOE at December 31, 2014 and 2013, respectively. The Company added 10,125 MBOE to its PUDs, net of revisions, primarily from the continued horizontal development of its Permian Basin properties and from acquisitions in the Permian Basin. The increase in Permian Basin PUDs was partially offset by the reclassification of 1,757 MBOE, or 24%, included in the year-end 2013 PUD reserves, to PDPs as a result of our horizontal development of Permian Basin properties at a total cost of approximately $34,619, net. Also offsetting the increase was the removal of 1,132 MBOE of PUDs, including the impact from the reclassification of previous vertical PUDs to the horizontal probable category given our focus on horizontal development.

The Company's PUDs increased 1% to 7,387 MBOE from 7,337 MBOE at December 31, 2013 and 2012, respectively. The Company added 5,168 MBOE to its PUDs, primarily from the continued horizontal development of its Permian Basin properties. The increase in Permian Basin PUDs was partially offset by 3,724 MBOE, or 51%, included in the year-end 2012 PUD reserves related to vertical PUD locations that were reclassified to horizontal probable reserves, and to a small extent, horizontal PDP and PUD categories. The reclassified vertical PUDs include locations that included certain target zones that were expected to be more efficiently developed by the Company's multi-level horizontal drilling programs initiated in 2012. Also offsetting the Permian Basin PUD growth were the sale of 1,297 MBOE, or 18%, included in the year-end 2012 PUD reserves related to our Medusa field and the conversion of a small portion of 2012 PUD reserves to PDPs during 2013 from the drilling of vertical wells.

The Company's PUDs decreased 18% to 7,337 MBOE from 8,925 MBOE at December 31, 2012 and 2011, respectively. Additions during the year added 2,344 MBOE to the Company's PUDs, offset by (1) 557 MBOE primarily comprised of transfers to PDPs as a result of our development program, (2) 1,148 MBOE related to the sale of Habanero, and (3) 2,227 MBOE related to reductions in our PUD reserves, primarily related to the Haynesville Shale, by amounts no longer deemed to be economic PUDs at year-end. Of the Company's year-end 2011 PUD reserves, 6% were converted to proved developed producing reserves by year end 2012, at a total cost of approximately $19 million, net.

Standardized Measure

The following tables present the standardized measure of future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2014. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and natural gas reserves. Prices are based on the preceding 12-months' average price based on closing prices on the first day of each month. The following table summarizes the average 12-month oil and natural gas prices net of differentials for the respective periods:

	2014	2013	2012
Average 12-month price, net of differentials, per Mcf of natural gas	$ 6.38	$ 5.45	$ 4.81
Average 12-month price, net of differentials, per barrel of oil	$ 86.30	$ 92.16	$ 94.68

Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

Natural gas production from our Permian Basin and former deepwater offshore properties has a high Btu content of separator natural gas. The natural gas per Mcf prices of $6.38, $5.45 and $4.81 used in the 2014, 2013 and 2012, respectively, reserve estimates include adjustments to reflect the Btu content, transportation charges and other fees specific to the individual properties. The oil prices per Bbl of $86.30, $92.16 and $94.68 used in the 2014, 2013 and 2012 reserve estimates have been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

	Standardized Measure For the Year Ended December 31,		
	2014	2013	2012
Future cash inflows	$ 2,492,178	$ 1,193,299	$ 1,115,570
Future costs			
Production	(873,469)	(357,005)	(249,329)
Development and net abandonment	(288,081)	(155,667)	(273,817)
Future net inflows before income taxes	1,330,628	680,627	592,424
Future income taxes	(164,490)	(68,239)	(55,772)
Future net cash flows	1,166,138	612,388	536,652
10% discount factor	(586,596)	(328,442)	(305,504)
Standardized measure of discounted future net cash flows	$ 579,542	$ 283,946	$ 231,148

	Changes in Standardized Measure For the Year Ended December 31,		
	2014	2013	2012
Standardized measure at the beginning of the period	$ 283,946	$ 231,148	270,357
Sales and transfers, net of production costs	(120,518)	(78,661)	(84,044)
Net change in sales and transfer prices, net of production costs	(156,066)	(46,088)	47,261
Net change due to purchases and sales of in place reserves	111,331	(145,711)	(35,665)
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	299,192	212,431	53,446
Changes in future development cost	186,605	153,983	39,815
Revisions of quantity estimates	(7,673)	(68,958)	(77,322)
Accretion of discount	30,114	25,010	30,989
Net change in income taxes	(32,940)	1,751	13,969
Changes in production rates, timing and other	(14,449)	(959)	(27,658)
Aggregate change	295,596	52,798	(39,209)
Standardized measure at the end of period	$ 579,542	$ 283,946	$ 231,148

Note 14 – Other

Commitments and contingencies

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability hereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment are not expected to have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies hereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Operating leases

In April 2012, the Company contracted a drilling rig (the "Cactus 1 Rig"), which it subsequently renewed in December 2014 for a term of two years ending November 2016. In April 2014, the Company contracted an additional horizontal drilling rig (the "Cactus 2 Rig"), which it subsequently renewed in December 2014 for a term of two years ending in November 2016. The Cactus 2 Rig replaced a previously contracted horizontal drilling rig, which was cancelled in March 2014. In August 2014, the Company signed a one-year contract for a vertical drilling rig to be used as part of its horizontal drilling program, drilling the vertical section of horizontal wells. The rig lease agreements include early termination provisions that would reduce the minimum rentals under the agreement, and also include provisions that would reduce the minimal rental payments assuming the lessor is able to re-charter the rig and staffing personnel to another lessee. Subsequent to December 31, 2014, the Company decided to terminate its one-year contract for the vertical rig effective April 2015 and currently may be required to pay approximately $3,733 in reduced rental payments over the remainder of the lease term. Also subsequent to December 31, 2014, the Company extended the terms of its Cactus 1 Rig and Cactus 2 Rig to end in July 2018 and August 2018, respectively. Lease payments in 2014 were $17,877 and are expected to approximate $16,893 (including early termination payments), $10,980, $10,950 and $6,510 in 2015, 2016, 2017 and 2018, respectively.

Other property and equipment

During 2012, the Company sold certain specialized deep water property and equipment valued at $527 and determined that certain equipment components were not usable without additional rework and thus recorded an impairment charge to with respect to such equipment of $1,177. During 2013, after selling certain specialized deep water property and equipment valued at $114, the Company made a decision to abandon the equipment. As such the Company recorded an impairment charge of $1,707 representing the remaining value of this equipment. During 2014, the Company entered into an agreement to sell the property and equipment to a third party. As a result of the subsequent sale of the property and equipment, the Company recognized a gain of $1,080.

Note 15 – Summarized Quarterly Financial Information (Unaudited)

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 33,285	$ 40,502	$ 39,657	$ 38,418
Income from operations	6,645	12,080	11,562	7,983
Net income	1,863	4,740	12,201	18,962
Income (loss) available to common shares	(111)	2,767	10,227	16,988
Income (loss) per common share - basic	$ 0.00	$ 0.07	$ 0.24	$ 0.31
Income (loss) per common share - diluted	$ 0.00	$ 0.07	$ 0.23	$ 0.30

2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 22,541	$ 22,760	$ 30,797	$ 26,471
Income from operations	898	957	6,345	2,464
Net income (loss)	(800)	758	1,082	3,264
Income (loss) available to common shares	(800)	78	(892)	1,291
Income (loss) per common share - basic	$ (0.02)	$ —	$ (0.02)	$ 0.03
Income (loss) per common share - diluted	$ (0.02)	$ —	$ (0.02)	$ 0.03

ITEM 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

There have been no disagreements with the independent auditors on any matters of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

Item 9A. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2014.

Management's report on internal control over financial reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control structure is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles. Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 based on the framework in *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission (2013 framework)(the COSO criteria). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm has issued an attestation report regarding its assessment of the Company's internal control over financial reporting as of December 31, 2014, which follows Part II, Item 9B of this filing. Additionally, the financial statements for each of the years covered in this Annual Report on Form 10-K have been audited by an independent registered public accounting firm, Ernst & Young LLP whose report is presented immediately preceding the Company's financial statements included in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in internal control over financial reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

ITEM 9A (T). Controls and Procedures

See Item 9A.

ITEM 9B. Other Information

Submissions of matters to a vote of the security holders

None.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited Callon Petroleum Company's internal control over financial reporting as of December 31, 2014 based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework)(the COSO criteria). Callon Petroleum Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Callon Petroleum Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Callon Petroleum Company as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014, and our report dated March 4, 2015 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 4, 2015

PART III.

ITEM 10. Directors, Executive Officers and Corporate Governance

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 14, 2015 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

The Company has adopted a code of ethics that applies to the Company's chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company's website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at mailing address Post Office Box 1287, Natchez, Mississippi 39121.

ITEM 11. Executive Compensation

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 14, 2015 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 14, 2015 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

For information concerning Item 13, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 14, 2015 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

For information concerning Item 14, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 14, 2015 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Item 15. Exhibits

The following is an index to the financial statements and financial statement schedules that are filed in Part II, Item 8 of this report on Form 10-K.

Exhibit			Description
1			The following is an index to the financial statements and financial statement schedules that are filed in Part II, Item 8 of this report on Form 10-K.
			Report of Independent Registered Public Accounting Firm
			Consolidated Balance Sheets as of December 31, 2014 and 2013
			Consolidated Statements of Operations for each of the three years in the period ended December 31, 2014
			Consolidated Statements of Stockholders' Equity (Deficit) for each of the three years in the Period Ended December 31, 2014
			Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2014
			Notes to Consolidated Financial Statements
2			Schedules other than those listed above are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.
3		Exhibits	
	2		Plan of acquisition, reorganization, arrangement, liquidation or succession*
	3		Articles of Incorporation and Bylaws
		3.1	Certificate of Incorporation of the Company, as amended through January 17, 2014 (incorporated by reference to Exhibit 3.1 of the Company's Form 10-Q filed on August 6, 2014
		3.2	Certificate of Designation of Rights and Preferences of 10% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Form 8-A filed on May 23, 2013.
		3.3	Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
	4		Instruments defining the rights of security holders, including indentures
		4.1	Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
		4.2	Certificate for the Company's 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company's Form 8-A filed May 23, 2013
	9		Voting trust agreement
			None
	10		Material contracts
		10.1	Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement on Schedule 14A, filed March 28, 2000, File No. 001-14039)
		10.2	Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)
		10.3	Amendment No. 3 to the Callon Petroleum Company 1996 Stock Incentive Plan (incorporated by reference from Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
		10.4	Amendment No. 1 to the Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference from Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
		10.5	Callon Petroleum Company Amended and Restated 2006 Stock Incentive Plan (incorporated by reference from Exhibit 10.3 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)

	10.6	Callon Petroleum Company 2009 Stock Incentive Plan effective as of April 30, 2009 (incorporated by reference from Exhibit A to the Company's Definitive Proxy Statement on Schedule 14A, filed March 30, 2009, File No. 001-14039)
	10.7	Amendment to the Callon Petroleum Company 1996 Stock Incentive Plan effective as of August 7, 2009 (incorporated by reference from Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2009, File No. 001-14039)
	10.8	Callon Petroleum Company 2010 Phantom Share Plan, adopted May 4, 2010 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on May 7, 2010)
	10.9	Form of Callon Petroleum Company Phantom Share Award Agreement, adopted May 4, 2010 (incorporated by reference to Exhibit 10.2 of the Company's current Report on Form 8-K filed on May 7 , 2010)
	10.10	Deferred Compensation Plan for Outside Directors; Callon Petroleum Company (effective as of January 1, 2011) (incorporated by reference to Exhibit 10.17 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-14039)
	10.11	Amended and Restated Severance Compensation Agreement, dated as of March 15, 2011 and effective as of January 1, 2011, by and between Fred L. Callon and Callon Petroleum Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on March 18, 2011)
	10.12	Form of Amended and Restated Severance Compensation Agreement, dated as of March 15, 2011 and effective as of January 1, 2011, by and between Callon Petroleum Company and its executive officers (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on March 18, 2011)
	10.13	Callon Petroleum Company 2011 Omnibus Incentive Plan (incorporated by reference from Exhibit A of the Company's Definitive Proxy Statement on Schedule 14A filed March 21, 2011, File No. 14039)
	10.14	Agreement, dated March 9, 2014, among the Company and Lone Star Value Investors, L.P., Lone Star Value Co-Invest I, L.P., Lone Star Value Investors GP, LLC, Lone Star Value Management, LLC, Jeffery E. Eberwein and Matthew R. Bob (incorporated by reference from Exhibit 10.1 on Form 8-K, filed on March 10, 2014, File No. 001-14039)
	10.15	Fifth Amended and Restated Credit Agreement among Callon Petroleum Company, JPMorgan Chase Bank, National Association, as administrative agent and the Lenders and parties named therein dated March 11, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Report on Form 10-Q/A filed June 11, 2014)
	10.16	Operator Resignation and Transition Agreement between Callon Petroleum Operating Company and Henry Resources LLC dated August 29, 2014 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed October 14, 2014)
	10.17	Purchase and Sale Agreement between Callon Petroleum Operating Company, as Purchaser, and NAWAB energy partners, lp and NAWAB WI, lp, as Sellers, dated August 29, 2014 (incorporated by reference to Exhibit 10.2 of the Company's Report on Form 8-K filed October 14, 2014)
	10.18	Purchase and Sale Agreement between Callon Petroleum Operating Company, as Purchaser, and Hedloc Investment Co. LP, as Seller, dated August 29, 2014 (incorporated by reference to Exhibit 10.3 of the Company's Report on Form 8-K filed October 14, 2014)
	10.19	Amendment No. 2 to Fifth Amended and Restated Credit Agreement among Callon Petroleum Company, JPMorgan Chase Bank, National Association, as administrative agent and the Lenders and parties named therein dated October 8, 2014 (incorporated by reference to Exhibit 10.4 of the Company's Report on Form 8-K filed October 14, 2014)
	10.20	Second Lien Credit Agreement among Callon Petroleum Company, Royal Bank of Canada and the Lenders party thereto, dated October 8, 2014 (incorporated by reference to Exhibit 10.5 of the Company's Report on Form 8-K filed October 14, 2014)
	10.21	Second Lien Intercreditor Agreement among Callon Petroleum Company, JPMorgan Chase Bank, National Association, Royal Bank of Canada, and the other parties named therein dated October 8, 2014 (incorporated by reference to Exhibit 10.6 of the Company's Report on Form 8-K filed October 14, 2014)
11		Statement re computation of per share earnings*
12		Statements re computation of ratios*
13		Annual Report to security holders, Form 10-Q or quarterly reports*

14		Code of Ethics
	14.1	Code of Ethics for Chief Executive Officers and Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Company’s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
16		Letter re change in certifying accountant*
18		Letter re change in accounting principles*
21		Subsidiaries of the Company
	21.1	Subsidiaries of the Company
22		Published report regarding matters submitted to vote of security holders*
23		Consents of experts and counsel
	23.1	Consent of Ernst & Young LLP
	23.2	Consent of DeGolyer and MacNaughton, Inc.
	23.3	Consent of Huddleston & Co., Inc.
24		Power of attorney*
31		Rule 13a-14(a) Certifications
	31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
	31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)
32		Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)
99		Additional Exhibits
	99.1	Reserve Report Summary prepared by DeGolyer and MacNaughton, Inc. as of December 31, 2014
101		Interactive Data Files **

*	Not applicable to this filing
**	Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

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.

		Callon Petroleum Company
Date:	March 4, 2015	/s/ Joseph C. Gatto, Jr.
		By: Joseph C. Gatto, Jr., senior vice president, chief financial officer (principal financial officer) and treasurer

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.

Date:	March 4, 2015	/s/ Fred L. Callon
		Fred L. Callon (principal executive officer, director)
Date:	March 4, 2015	/s/ Joseph C. Gatto, Jr.
		Joseph C. Gatto, Jr. (principal financial officer)
Date:	March 4, 2015	/s/ Mitzi P. Conn
		Mitzi P. Conn (principal accounting officer)
Date:	March 4, 2015	/s/ L. Richard Flury
		L. Richard Flury (director)
Date:	March 4, 2015	/s/ John C. Wallace
		John C. Wallace (director)
Date:	March 4, 2015	/s/ Anthony J. Nocchiero
		Anthony J. Nocchiero (director)
Date:	March 4, 2015	/s/ Larry D. McVay
		Larry McVay (director)
Date:	March 4, 2015	/s/ Matthew R. Bob
		Matthew R. Bob (director)
Date:	March 4, 2015	/s/ James M. Trimble
		James M. Trimble (director)

Corporate Data

Board of Directors

Fred L. Callon
Chairman, President
and Chief Executive Officer

L. Richard Flury
Former Chief Executive
Gas, Power & Renewables (Retired)
British Petroleum plc

Larry D. McVay
Former Chief Operating Officer
TNK-BP Holdings (Retired)
British Petroleum plc Joint Venture

Anthony J. Nocchiero
Former Sr. Vice President
and Chief Financial Officer
CF Industries, Inc. (Retired)

John C. Wallace
Former Chairman, Fred. Olsen Ltd. (Retired)
Director, Siem Offshore Inc.; Secunda Canada LP
London, England

Matthew R. Bob
President, Eagle Oil & Gas Company

James M. Trimble
Chief Executive Officer and President
of PDC Energy (Retired)

Officers of the Company

Fred L. Callon
Chairman, President
and Chief Executive Officer

Gary A. Newberry
Senior Vice President, Operations

Joseph C. Gatto, Jr.
Chief Financial Officer,
Senior Vice President and Treasurer

B.F. Weatherly
Corporate Secretary

Jerry A. Weant
Vice President, Land

Mitzi P. Conn
Corporate Controller

Transfer Agent and Registrar

American Stock Transfer
& Trust Company, LLC
6201 15th Avenue
Brooklyn, New York 11219
(718) 921-8200

Legal Counsel

Haynes and Boone, LLP
Houston, Texas

Independent Registered Public Accounting Firm

Ernst & Young LLP
New Orleans, Louisiana

Administrative Agent Bank

JPMorgan Chase Bank, N.A.
New York, New York

Corporate Offices

Callon Headquarters Building
200 North Canal Street
Natchez, Mississippi 39120

Mailing Address:
Callon Petroleum Company
PO Box 1287
Natchez, Mississippi 39121

Callon Petroleum Company
1401 Enclave Parkway, Suite 600
Houston, Texas 77077

Callon Petroleum Company
4305 North Garfield Street, Suite 235
Midland, Texas 79705

Form 10-K

The Company's annual report on Form 10-K, excluding exhibits, has been incorporated into this Annual Report.

Callon Website

The Company website can be found at www.callon.com. It contains news releases, corporate governance materials, the annual report, recent investor presentations, stock quotes and a link to SEC filings.

Common Stock Dividend Policy

It is anticipated that all available funds will be reinvested in the Company's business activities. Therefore, the Company does not anticipate paying cash dividends on its common stock for the foreseeable future.

Market for Common Stock

Effective April 22, 1998, the Company's Common Stock began trading on the New York Stock Exchange under the symbol "CPE."

Preferred Stock Dividend Policy

Holders of our Series A preferred stock (NYSE: CPE.A) are entitled to a cumulative dividend, whether or not declared, of $5.00 per annum, payable quarterly, equivalent to 10% of the liquidation preference of $50.00 per share.

CEO Section 303A.12(a) Certification

In accordance with requirements mandated by the New York Stock Exchange under Section 303A.12 (a) of the Listed Company Manual, each public company is required to disclose in its Annual Report to Shareholders that its CEO certification was filed and to state any qualifications to such certification. On behalf of Fred L. Callon, the Company filed the required certification on March 4, 2015 without qualification.

Notice of Annual Shareholders' Meeting

The Annual Meeting of Shareholders will be held Thursday, May 14, 2015 at 9:00 a.m. in the Grand Ballroom of the Natchez Grand Hotel, 111 South Broadway Street, Natchez, MS 39120. Information with respect to this meeting is contained in the Proxy Statement sent to shareholders of record on March 27, 2015. The 2014 Annual Report is not to be considered a part of the proxy soliciting materials.

2014 Annual Report

This Annual Report and the statements contained in it are submitted for the general information of the shareholders of Callon Petroleum Company. The information is not presented in connection with the sale or the solicitation of any offer to buy any securities, nor is it intended to be a representation by the Company of the value of its securities. If you have questions regarding this Annual Report or the Company, or would like additional copies of this report, please contact our Investor Relations Department at 1401 Enclave Pkwy, Ste 600, Houston, TX 77077 Phone: (281) 589-5200. In accordance with SEC rules, you may access the Annual Report at www.callon.com, which does not have "cookies" that identify visitors to the site.

Security analysts and investment professionals should direct written inquiries to Joe Gatto, Chief Financial Officer and Treasurer, Callon Petroleum Company, 1401 Enclave Parkway, Suite 600, Houston, TX 77077 Phone: (281) 589-5200, Fax: (281) 589-5215

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