CALLON PETROLEUM CO
Form 10-K
March 13, 2014

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

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013
OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(D) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-14039

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

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

(Registrant's Telephone Number, Including Area Code): 601-442-1601
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 ý
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 ý
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 ý 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 ý 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 ý
Non-accelerated filer ¨	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 ý

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2013 was approximately $129.6 million.

As of March 10, 2014, 40,465,227 shares of the Registrant’s common stock, par value $.01 per share, were outstanding.

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, 2013) relating to the Annual Meeting of Stockholders to be held on May 15, 2014, which are incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Special Note Regarding Forward Looking Statements

All statements, other than historical fact or present financial information, 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. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

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-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or si

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 commodities (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 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 Securities and Exchange Commission.

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, 2013 and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or elsewhere in this 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 statutorily prescribed meanings when used in this report. As used in this document:

- 3-D: three-dimensional.
- ARO: Asset Retirement Obligation.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- Bcf: billion cubic feet.
- 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.
- BOE/d: BOE per day.
- BLM: Bureau of Land Management.
- BOEM: Bureau of Ocean Energy Management, Regulation and Enforcement; formerly the Minerals Management Service.
- 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.
- BSEE: Bureau of Safety and Environmental Enforcement.
- DOI: Department of Interior.
- EPA: Environmental Protection Agency.
- GHG: greenhouse gases.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand boe.
- MBOE/d: Mboe per day.
- Mcf: thousand cubic feet of natural gas.
- Mcfe: thousand cubic feet of natural gas equivalents.
- Mcf/d: Mcf per day.
- MMBbls: million barrels of oil.
- MMBOE: million BOE.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- MMS: Minerals Management Service.
- 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.
- GAAP: Generally Accepted Accounting Principles in the United States

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. 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 unle the context requires otherwise.

In 2013, the Company completed its onshore strategic repositioning that began in 2009, shifting its operations from the offshore waters in the Gulf of Mexico to the onshore, Permian Basin in Texas. In the fourth quarter of 2013, the Company sold its interest in its only remaining deepwater property, the Medusa field, in addition to the sale of the Medusa spar facility and substantially all remaining offshore shelf properties. Previously, Callon sold its interest in its deepwater Habanero field in the fourth quarter of 2012. Collectively, these transactions completed the Company’s transition to an onshore operator with an asset base concentrated exclusively in the Midland Basin, a sub-basin contained in the broader Permian Basin.

Callon exited 2013 with average Permian production in the month of December of 3,611 BOE/d (approximately 84% oil), a 129% increase over our exit rate in 2012. We believe that the Company’s transition to a horizontal development program, which was expanded from two fields to four fields in late 2013, has improved Callon’s overall capital efficiency and has contributed to a net increase of 59% in the Company’s Permian proven reserve base.

The Company operates 100% of its Permian acreage, which provides additional flexibility to modify development plans to address potential changes in the operating and commodity price environments. As of December 31, 2013, we had estimated net proved reserves of 11.9 MMBbls and 17.8 Bcf, or 14.9 MMBOE, all of which were located in the Permian Basin, compared with approximately 67% located in the Permian Basin at December 31, 2012. Additionally, 80% of our proved reserves were crude oil and 50% were proved developed at year-end 2013, on a BOE basis.

Our Business Strategy

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

Drive production and reserve growth through horizontal development of our resource base. Our initial drilling efforts in the Permian Basin targeted the development of multiple zones with vertical wells as part of the “Wolfberry” play. As part of this drilling program, we amassed 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 Callon to initiate the horizontal development of our resource base in 2012. Importantly, we believe horizontal development of our resource base will provide the opportunity to improve returns relative to vertical drilling by accessing a larger base of reserves in target zone with a lateral wellbore. During the fourth quarter of 2013, approximately 44% of our total Permian production was sourced from horizontal wells. We expect the contribution of horizontal production volumes from our existing properties to increase with the recent expansion of our horizontal development efforts to four fields as part of our current two-rig drilling program.

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 shales, establishing production from both zones in the Southern Midland Basin. We have been focused on these development zones to reduce drilling risk as we continue to grow our asset base in the Permian Basin. We believe additional opportunities exist to selectively target various other prospective zones including the Jo-Mill, Lower Spraberry, Wolfcamp A, Wolfcamp C and Cline formations, and plan to selectively drill potential identified locations to complement our core development efforts in the Wolfcamp B. Moreover, we will monitor the efficiency of our horizontal wells related to reservoir drainage over time and pursue downspacing initiatives within target zones if overall returns can be enhanced. We recently transitioned to closer spacing of our horizontal laterals in the Southern Midland Basin in both the Upper and Lower Wolfcamp B shales.

Outside of our core development areas in the Southern and Central Midland Basin, we maintain an exploration position in the Northern Midland Basin. Our current activity in the Northern Midland Basin is limited to vertical drilling in order to assess resource potential and economic returns. If our exploration concept is proven to economically produce hydrocarbons on a repeatable basis from vertical wells, we will then determine whether the testing of horizontal development concepts is warranted.

Pursue selective acquisitions in the Permian Basin. We have demonstrated our ability to acquire and trade acreage in the Midland Basin. Specifically, we added our Taylor Draw field in 2012 and Garrison Draw Field in 2013 for a total of $23 million, including acquired production and proved reserves. These two fields are now part of our core horizontal development plan. We have built on these acquisitions with recent acquisitions of acreage near our existing East Bloxom (see Recent Developments below), as well as completing an acreage trade at Garrison Draw which added contiguous acreage for effective long lateral horizontal development. 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.

Capitalize on opportunities to further reduce cost of capital. Following the disposition of our offshore properties, we have the opportunity to recapitalize the Company with a lower cost of capital commensurate with an improved credit risk profile as a purely onshore operator. As part of an ongoing effort to reduce our cost of capital, we have redeemed nearly $90 million of our 13% Senior Notes due 2016 (the "Senior Notes") since 2011 and recently called for the redemption of the remaining $49 million of principal to occur in April 2014, replacing these Senior Notes with lower cost financing. Additionally, we believe the demonstrated growth in our proved developed reserve base provides the foundation for a meaningful expansion of our borrowing base capacity under our revolving credit agreement. We recently increased the notional amount and reduced the interest expense related to our revolving credit agreement, evidencing another step in reducing our overall cost of capital (see Recent Developments below).

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 13,600 net 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, 2013, our estimated net proved reserves were comprised of approximately 80% oil and 20% natural gas, which includes NGLs in the production stream. This oil exposure provides us the opportunity to benefit from currently more favorable prices as compared to natural gas.

Multi-year drilling inventory. Our current acreage position in the Permian Basin provides visible growth potential from a horizontal drilling inventory of almost 20 years based on our current two-rig horizontal drilling program. As of December 31, 2013, 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, we have identified an inventory of approximately 540 potential horizontal well locations in multiple horizons across our Southern and Central Midland Basin acreage. Of these potential locations, approximately 225 are identified in the Upper Wolfcamp B, Lower Wolfcamp B and Wolfcamp A zones which have been drilled on our acreage and are currently producing.

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. For example, our average drill time for a typical 7,800 foot lateral Wolfcamp shale well decreased from approximately 30 days at the start of our drilling program in 2012 to under 20 days as of February 2014. 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 all of our Permian Basin acreage, providing us the opportunity to modify our operational plans to respond to changes in operational and commodity price environments. This operating control also allows us to modify drilling and completion techniques, and change drilling schedules 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 established a Health, Safety and Environmental department dedicated to our operations in the Permian Basin. This group is responsible for monitoring the activity and safety compliance of both our employees as well as third party service providers and consultants. 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. As an example, we were recently awarded the Midland Bruno Hanson/Midland College Award for Environmental Excellence which is given to companies that demonstrate strong environmental stewardship in the Permian Basin.

Financial flexibility to fund growth initiatives. We bolstered our capital structure in 2013 with the issuance of Series A Cumulative Preferred Stock and the sale of our offshore assets. We have continued to build upon these transactions with the recent completion of the Amended Credit Facility and Second Lien Facility as described in Recent Developments.

Exploration and Development Activities

Our 2013 total capital expenditures, on a cash basis and including acquisitions, were $171 million, representing a 17% increase over 2012 actual capital expenditures. Of the $171 million, approximately $145 million was allocated to onshore drilling, development and leasehold acquisition activity in the Permian basin. During 2013, capital expenditures for exploration and development costs related to oil and natural gas properties included the following expenditures (in millions):

Southern Midland Basin	$111
Central Midland Basin	20
Northern Midland Basin	7
Other	7
Total capital expenditures	145
Capitalized general and administrative costs allocated directly to exploration and development projects	11
Capitalized interest	4
Total capitalized expenses	15
Total operational expenditures	160
Acquisitions	11
Total capital expenditures, including acquisitions	$171

We expanded our horizontal pad development efforts from two to four fields in late 2013, adding Carpe Diem in Midland County and Garrison Draw in Reagan County. We expect our 2014 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 two wells in the Southern Midland Basin to evaluate the Wolfcamp A shale and a test of the Lower Spraberry shale formation in the Central Midland Basin. Planned vertical drilling activity is anticipated to be limited to five deep Wolfberry wells in the Pecan Acres field and one well in the Garrison Draw field. In addition, our plans include three vertical exploration wells in the Northern Midland Basin, the timing and location of which being subject to change as results are evaluated during the course of 2014.

Recent Developments

Credit facilities

On March 11, 2014, we entered into an amended senior secured revolving credit facility (the “Amended Credit Facility”) in the amount of $500 million with JPMorgan Chase Bank, N.A. as Administrative Agent (“J.P. Morgan”). The Credit Facility will have an initial borrowing base amount of $95 million and a maturity date of March 11, 2019. In conjunction with the Amended Credit Facility, we entered into a senior secured second lien term loan facility (the “Second Lien Facility”) in an aggregate amount of up to $125 million with J.P. Morgan as Administrative Agent and with a maturity date of September 11, 2019. See Note 4 for additional information.

Acquisitions

During the first quarter of 2014, we added 1,280 net acres in Upton County near our existing core development fields for an aggregate purchase price of $7.0 million. This acreage added an estimated 96 gross potential horizontal well locations from seven prospective zones to our drilling inventory. In addition, we expect to leverage existing infrastructure from our East Bloxom field in the development of this new acreage. See Notes 6 and 12 to our financial statements for additional information regarding acquisitions.

Table of Contents

Divestitures

Effective December 5, 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. The Company sold these assets to W&T Offshore, Inc., an unrelated third-party, for total net cash consideration of approximately $100 million before customary purchase price adjustments. The Medusa field had production net to Callon of 582 MBOE in 2013. Also during the fourth quarter of 2013, the Company closed on the sale of its 69% interest in the Swan Lake field for $2 million. This field included 429 net acres and produced approximately 107 MMcf during the year ended December 31, 2013. This was the Company's only field in the Haynesville shale. See Note 12 to our financial statements for additional information.

Oil and Natural Gas Properties

As of December 31, 2013, our estimated net proved reserves totaled 14.9 MMBOE and included 11.9 MMBbls and 17.8 Bcf, with a pre-tax present value, discounted at 10%, of $301.1 million. Pre-tax present value is a non-GAAP financial measure, which we reconcile to the GAAP measure of standardized measure of $283.9 million in note (d) to the table below. Oil constituted approximately 80% of our total estimated equivalent net proved reserves and approximately 80% 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, 2013:

	Estimated Net Proved Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE) (a)	Pre-tax Discounted Present Value ($000) (b)(c)(d)
Southern Midland Basin	10,103	15,021	12,607	$267,216
Central Midland Basin	1,699	2,730	2,154	39,336
Northern Midland Basin	96	—	96	3,921
Other (c)	—	—	—	(9,329)
Total	11,898	17,751	14,857	$301,144

(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, 2013, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc.

(c) Includes a reduction for estimated plugging and abandonment costs that are reflected as a liability on our balance sheet at December 31, 2013, 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, 2013 was $283.9 million inclusive of the $17.2 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $5.45 used in the 2013 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 $92.16 used in the 2013 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, 2013, we owned approximately 31,829 net acres in the Permian Basin. Our reserves in the Permian Basin represent all of our proved reserves at year-end 2013 as compared to 67% at year-end 2012. Average net production from the Company's Permian Basin properties increased 38% to 2,227 BOE/d in 2013 from 1,619 BOE/d in 2012. As of December 2013, our average daily net production from the Permian Basin was 3,611 BOE/d.

Southern Midland Basin

- Counties (fields): Upton (East Bloxom), Reagan (Taylor Draw and Garrison Draw) and Crockett (Block 5)
- 8,904 net acres as of December 31, 2013
- 77 producing wells (17 horizontal)
- Initiated horizontal development in 2012
- 4th quarter 2013 net production: 2,334 BOE/d (72% horizontal)

The Southern Midland Basin is our largest operating area in terms of production. Following recently completed acquisitions in the first quarter of 2014, we currently have approximately 10,200 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 across our entire position in the Southern Midland Basin in 2014 and expect to test additional zones in future years.

Central Midland Basin

- Counties (fields): Midland (Carpe Diem and Pecan Acres) and Ector (Kayleigh)
- 3,359 net acres as of December 31, 2013
- 50 producing vertical wells
- Initiated horizontal development in 2013
- 4th quarter 2013 net production: 564 BOE/d

The Central Midland Basin has been the focus of our high-graded vertical drilling program, targeting multiple zones down to the Woodford shale. We have recently shifted our focus to horizontal development of the Carpe Diem field. Our first Wolfcamp B wells were placed on production in the first quarter of 2014 and we plan to add Carpe Diem to our core development fields going forward. This area is prospective for multiple horizontal development zones and we plan to target the Lower Spraberry in 2014 as we delineate zones outside of the Wolfcamp B.

Northern Midland Basin

- Counties (fields): Borden (Black Magic and Baird Ranch) and Lynn (Tahoka Prospect)
- 19,566 net acres as of December 31, 2013
- One producing vertical well
- Ongoing going exploration and delineation activity

Our Northern Midland Basin position was established in 2012 with the acquisition of 21,617 net acres in Borden and Lynn Counties. We currently own approximately 17,433 net acres following our decision to allow certain acreage in the Northern Midland Basin to expire as we refine our targeted areas for exploration. We began our exploration program in Borden County during the second half of 2012, drilling one gross (0.75 net) vertical and two gross (1.5

net) horizontal wells, targeting the Cline and Mississippi lime. We have subsequently focused our exploration activity on the Mississippi chat, drilling a vertical well (Lacey Newton 2801) in late 2013. We plan to further evaluate the areal extent of this prospective play with at least one vertical exploration well in Borden County in 2014. We also plan to drill our first exploration well in Lynn County in the first half of 2014, testing several prospective zones, including the Spraberry.

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 approximately 65,000 net acres located in various counties in Nevada. These leases are with the Bureau of Land Management and carry a primary term that expires in 2018. 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.

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 an 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 2011 and 2012.

	Years Ended December 31,		
	2013	2012	2011
Proved developed:			
Oil (MBbls)	5,960	4,955	5,069
Natural gas (MMcf)	9,059	10,680	11,605
MBOE	7,470	6,735	7,003
Proved undeveloped:			
Oil (MBbls)	5,938	5,825	5,006
Natural gas (MMcf)	8,692	9,073	23,513
MBOE	7,387	7,337	8,925
Total proved:			
Oil (MBbls)	11,898	10,780	10,075
Natural gas (MMcf)	17,751	19,753	35,118
MBOE	14,857	14,072	15,928
Financial Information:			
Estimated pre-tax future net cash flows (a)	$680,627	$592,424	$568,798
Pre-tax discounted present value (a) (b)	$301,144	$250,097	$309,890
Standardized measure of discounted future net cash flows (a) (b)	$283,946	$231,148	$270,357

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

(b) 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, 2013 was $283.9 million inclusive of the $17.2 million discounted estimated future income taxes relating to such future net revenues. The natural gas Mcf prices of $5.45 used in the 2013 reserve estimates have been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected oil prices of $92.16 used in the 2013 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.

See Note 12 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 6% to 14,857 MBOE from 14,072 MBOE at December 31, 2013 and 2012, respectively. Additions during the year were 9,979 MBOE, primarily due to the Company's horizontal development of a portion of its Permian Basin properties. These increases were partially offset by (1) 4,057 MBOE related to the sale of the Company's Gulf of Mexico assets and Haynesville field, (2) 3,724 MBOE of reductions in the Company's PUD reserves, primarily related to the reclassification of certain vertical PUD locations to the horizontal probable category, and a small amount to the horizontal PDP and PUD categories at year end and (3) 1,413 MBOE related to the Company's production during 2013. The reclassified vertical PUDs include Wolfberry PUD locations that included certain target zones that are now expected to be more efficiently developed by the Company's multi-level horizontal drilling programs initiated in 2012. The vast majority of these previously booked vertical PUDs are now internally classified as horizontal probable reserves, with a small amount now captured in horizontal PDPs and PUDs.

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 2014 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 2014 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:

	PUDs (MBOE) at December 31,		
	2013	2012	2011
Permian Basin	7,387	6,040	4,861
Haynesville shale	—	—	1,730
Total Onshore	7,387	6,040	6,591
Medusa (a)	—	1,297	1,186
Habanero (b)	—	—	1,148
Total Offshore	—	1,297	2,334
Total	7,387	7,337	8,925

(a) Effective July 1, 2013, we sold our interest in the Medusa field. See Note 12 for additional information.
(b) Effective December 28, 2012, we sold our interest in the Habanero field. See Note 12 for additional information.

Our PUDs increased 1% to 7,387 MBOE from 7,337 MBOE at December 31, 2013 and 2012, respectively. We added 5,168 MBOE to the Company's PUDs, primarily from the continued horizontal development of our Permian Basin properties. The increase in Permian Basin PUDs was partially offset by the reclassification of 3,724 MBOE, or 51% of volumes included in year-end 2012 PUD reserves related to vertical PUD locations that were moved to the horizontal probable category, and a small amount to the horizontal PDP and PUD categories, as we believe the previously booked Wolfberry PUD locations included certain target zones that we now expect can be more effectively developed over the next five years by our multi-level horizontal drilling program that was commenced during 2012. Also offsetting our PUD additions was 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 our 2012 PUD reserves to PDPs during 2013 from vertical drilling for a net cost of approximately $6 million. Most of our PUDs at year-end 2012 were attributable to vertical well locations. During 2013, our drilling program was predominantly focused on horizontal wells as we continued to delineate our acreage for horizontal development of multiple zones that were previously the target of vertical development wells. Based on our horizontal drilling results and subsequent capital allocation decisions, only three of the vertical wells previously included as PUDs in our 2012 reserve report were drilled in 2013. Our horizontal drilling program converted 4,431 MBOE of reserves that were not classified as proved at year end 2012 to proved developed reserves at year end 2013.

The Company plans to develop its Permian Basin PUDs as part of a multi-year drilling program. At December 31, 2013, we had no reserves that remained undeveloepd 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.

Table of Contents

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 26 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 Huddleston & Co., Inc. ("Huddleston"), a Texas registered engineering firm, as our independent petroleum and geological firm. The Company provided to Huddleston information about our oil and gas properties, including production profiles, prices and costs, and Huddleston prepared its own estimates of the reserves attributable to the Company's properties. All of the information regarding reserves in this annual report is derived from Huddleston's report. Huddleston's reserve report letter is included as an Exhibit to this annual report. The principal engineer at Huddleston who is responsible for preparing the Company's reserve estimates has over 30 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.

To further enhance the control environment over the reserve estimation process, our Board of Directors includes a Strategic Planning Committee whose purpose, as stated in the Committee's charter, includes assisting 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 Huddleston. 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.

	Years Ended December 31,		
	2013	2012	2011
	(in thousands, except per unit data)		
Production			
Oil (MBbls)	911	977	996
Natural gas (Mcf)	3,011	3,588	5,081
Total (MBOE)	1,413	1,575	1,843
Revenues			
Oil sales	$88,960	$96,584	$100,962
Natural gas sales	13,609	14,149	26,682
Total revenues	$102,569	$110,733	$127,644
Operating costs			
Lease operating expense	$19,779	$23,330	$18,285
Production taxes	4,133	3,224	2,062
Total operating costs	$23,912	$26,554	$20,347
Realized prices			
Oil ($/Bbl, including realized gains (losses) on derivatives) (a)	$97.65	$98.86	$101.34
Oil ($/Bbl, excluding realized gains (losses) on derivatives) (a)	97.65	97.41	101.72
Natural gas ($/Mcf, including realized gains (losses) on derivatives) (b)	4.52	3.94	5.25
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) (b)	4.52	3.94	5.25
Operating costs per BOE			
Lease operating expense	$14.00	$14.81	$9.92
Production taxes	2.92	2.05	1.12
Total operating costs per BOE	$16.92	$16.86	$11.04

(a) Oil prices for production from our two divested deepwater fields reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production, prior to the sale of Medusa in December 2013, and Argus Bonita WTI differential for Habanero production, prior to the sale of Habanero during December 2012.

(b) Natural gas prices exceeded the related NYMEX prices, which are quoted on an MMBtu basis, primarily due to the value of the NGLs in our liquids-rich natural gas stream, primarily from our Permian basin production.

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. At December 31, 2013, the Company had four wells awaiting fracture stimulation.

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	17	15.5	15	13.5	3	3.0
Total	18	16.5	16	14.5	3	3.0
Central Midland Basin						
Vertical wells	5	3.0	7	4.4	—	—
Horizontal wells	2	1.7	—	—	2	1.7
Total	7	4.7	7	4.4	2	1.7
Northern Midland Basin						