CALLON PETROLEUM CO
Form 10-K
March 14, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K
for the year ended
December 31, 2012

[X]	Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2012, or
[ ]	Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the transition period from____ to____

Commission File Number 001-14039
CALLON PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	64-0844345 (I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi (Address of principal executive offices)	39120 (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

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 [X]

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 [X]

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 [X]	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 [X]	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 [X]
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 [X]

The aggregate market value of the voting and non-voting common equity stock held by non-affiliates of the registrant was $162.0 million as of June 30, 2012.

As of March 8, 2013, 39,870,136 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, 2012) relating to the Annual Meeting of Stockholders to be held on May 16, 2013, 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 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-K 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 respond to low natural gas prices,
- 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 (“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, 2012 and all quarterly reports on Form 10-Q filed subsequently thereto (“Form 10-Qs”).

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.

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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 ("MMS").
- 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.
- 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.
- OCS: outer continental shelf.
- Oil: includes crude oil and condensate.
- ONRR: Office of Natural Resources Revenue.
- PDPs: proved developed producing reserves.
- PDNPs: proved developed non-producing reserves.
- PUDs: proved undeveloped reserves.
- Reserve life: a measurement of the time it will take to produce our proved reserves calculated by dividing our estimate net equivalent reserves at December 31, 2012 by our total production during 2012 on an equivalent basis.
- SEC: United States Securities and Exchange Commission.

- US 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.

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PART I.

Items 1 and 2 - Business and Properties

Overview and Business Strategy

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 2009, the Company began to shift its operational focus from exploration, development and production in the Gulf of Mexico to the acquisition and development of onshore properties. Currently, our onshore properties located in the Permian Basin in Texas are the foundation of our onshore strategy. As of December 31, 2012, we had estimated net proved reserves of 10.8 MMbbls and 19.8 Bcf, or 14.1 MMboe. Of these reserves and on an MMboe basis, approximately 68% were located onshore in the Permian Basin, compared with approximately 61% located onshore at December 31, 2011. Additionally, 77% of our proved reserve volumes were crude oil at year-end 2012 compared to 63% at year-end 2011.

Our Business Strategy

Our goal is to increase stockholder value by:

- Continuing to build our onshore production base through:
conversion of our existing Permian acreage position to production
leveraging our technical and operational teams across a larger production base
pursuing opportunistic producing property and leasehold acquisitions

- Focusing on capital efficiency through:
exploiting Permian resources through repeatable program drilling
continuing to invest in supporting infrastructure
high-grading of capital allocation across our expanded drilling portfolio continuing to refine our vertical and horizontal completion techniques and target zones

- Delivering on asset growth potential through:
focusing on an established production base from vertical Wolfberry wells
the drilling inventory of horizontal locations identified in 2012 from our evaluation efforts in the southern Midland basin from horizontal locations developed in 2012
exploration activities on our acreage in the northern Midland basin

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Our Strengths

We believe that we are well positioned to achieve our business objectives and to execute our strategy due to the following factors:

- We have assembled a Permian leasehold position of over 32,900 net acres that are prospective for the exploration, development and exploitation of multiple oil-bearing intervals through both vertical and horizontal drilling.

- Our initial horizontal drilling efforts commenced in 2012 have resulted in a large inventory of drillable locations in the southern Midland basin for future development of two zones of the Wolfcamp shale, complementing our existing vertical drilling program. We continue to evaluate other intervals prospective for horizontal development that may add to this inventory depending on evaluation results by us and other industry players.

- We continue to replace high decline-rate, natural gas production from the Gulf of Mexico shelf area with longer reserve life, liquids-rich production from our Permian drilling programs. As a result, we have increased our reserve life 185% to 8.9 years at year-end 2012 from 4.8 years at year-end 2008.

- Our offshore properties generate substantial cash flow, which we can redeploy in the acquisition, exploration and development of onshore properties. Since initiating our onshore transition strategy in 2009, we have invested nearly $263 million of offshore cash flow into our onshore initiatives.

- Effective December 28, 2012, we sold our interest in the Habanero field for net cash consideration of $39.4 million, accelerating our cash flows from this offshore property and monetizing the value of additional undeveloped reserve potential. These proceeds allowed us to substantially reduce the outstanding balance on our Senior Secured Revolving Credit Facility (the "Credit Facility"), strengthening our liquidity in 2013 to support our Permian-focused capital development program.

- On December 31, 2012, our total liquidity position was approximately $56.1 million, including $1.1 million of available cash and $55 million of unused borrowing base available under our Credit Facility. The $65 million borrowing base at December 31, 2012 increased by $20 million or 44% over the base at December 31, 2011.

- We have assembled a management team experienced in oil and natural gas acquisitions, exploration, development and production in the areas in which we focus our operations, with an average of 28 years of experience in their relevant fields of expertise. Our technical and operational teams continue to benefit from the knowledge gained from our increased level of activity in the Permian basin and from the addition of new employees with significant industry experience.

Exploration and Development Activities

Our 2012 capital expenditures approximated $147 million, and represented a 39% increase over 2011 actual capital expenditures. Of the $147 million, approximately 88% was allocated to onshore drilling, development and leasehold acquisition activity in the Permian basin. During 2012, capital expenditures on an accrual basis for exploration and development costs related to oil and natural gas properties included the following expenditures (in millions):

Southern Midland basin	$70.3
Northern Midland basin	21.4
Leasehold acquisitions and seismic	37.2
Plugging and abandonment costs in the Gulf of Mexico	2.3
Capitalized interest	2.0
Capitalized general and administrative costs allocated directly to exploration and development projects	13.3

Total capital expenditures	$146.5

With our continued operational focus onshore, primarily in the Permian basin, we expect that over 92% of our 2013 capital expenditures will be focused on the acquisition, exploration, development and operation of onshore properties, with only 8% of capital expenditures directed towards our offshore properties, excluding the capital required for the subsea development project discussed below. In addition to the 2013 capital program, which is outlined within Management's Discussion and Analysis (Part II, Item 7), we have received various long-lead time requests for capital expenditures related to the proposed subsea development of the Medusa field, and we expect to receive additional requests throughout 2013. The operator plans to begin drilling these

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wells will begin in the first quarter of 2014. For additional information, please refer to our Offshore - Deepwater discussion, which is also located within Management's Discussion and Analysis.

Recent Developments

Acquisitions

During the first quarter of 2012, the Company acquired approximately 16,233 gross (14,653 net) acres in Borden county, Texas, 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 risk of success for these drilling activities. The purchase price of $14.5 million 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 $4.8 million.

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 $12.0 million, which was financed with a draw on the Company's Credit Facility. The transaction had an effective date of May 1, 2012 and closed on July 5, 2012.

Divestitures

On December 28, 2012, we closed the sale of our 11.25% working interest in the Habanero field (Garden Banks Block 341) to Shell Offshore Inc., a subsidiary of Royal Dutch Shell Plc, for an estimated net cash consideration of $39.4 million after customary purchase price adjustments. We used the proceeds from the sale to reduce outstanding borrowings on our Credit Facility, providing additional liquidity to fund our 2013 capital program. The borrowing base under our Credit Facility was revised to $65 million following the Habanero sale, and was redetermined as scheduled in the first quarter of 2013 based upon the evaluation of year-end proved reserves.

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Crude Oil and Natural Gas Properties

As of December 31, 2012, our estimated net proved reserves totaled 14.1 MMBoe and included 10.8 MMBbls and 19.8 Bcf, with a pre-tax present value, discounted at 10%, of $250.1 million. Pre-tax present value is a non-US GAAP financial measure, which we reconcile to the US GAAP standardized measure of $231.1 million in note (d) to the table below. Oil constitutes approximately 77% of our total estimated equivalent net proved reserves and approximately 48% 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 field and for all other properties combined at December 31, 2012:

	Operator	Estimated Net Proved Reserves Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe) (a)	Pre-tax Discounted Present Value ($000) (b)(c)(d)
Onshore:					
Permian basin	Callon	7,209	13,242	9,416	$78,950
Haynesville shale	Callon	—	1,231	205	$666
Total Onshore		7,209	14,473	9,621	$79,616
Gulf of Mexico Deepwater:					
Mississippi Canyon 538/582 “Medusa”	Murphy	3,551	2,083	3,898	$179,967
Total Gulf of Mexico Deepwater		3,551	2,083	3,898	$179,967
Gulf of Mexico Shelf and Other:					
West Cameron Block 295	Apache	5	954	164	$1,081
East Cameron Block 2	Apache	5	487	86	633
East Cameron Block 257	SandRidge Energy	—	1,182	197	(718)
Other (c)	Various	10	574	106	(10,482)
Total Gulf of Mexico Shelf and Other		20	3,197	553	$(9,486)
Total Net Proved Reserves		10,780	19,753	14,072	$250,097

(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 an 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, 2012, 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 is reflected as a liability on our balance sheet at December 31, 2012, in accordance with accounting for asset retirement obligations rules. The negative Pre-Tax Discounted Present Value of the “Other” reflects plugging and abandonment obligations exceeding the future net cash flows, with most of such obligations estimated to occur within the next five years.

(d) The Company uses the financial measure “Pre Tax Discounted Present Value” which is a non-US GAAP financial measure. The Company believes that Pre Tax Discounted Present Value, while not a financial measure in accordance with US 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, 2012 was $231.1 million inclusive of the $18.9 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $4.81 used in the 2012 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 $94.68 used in the 2012 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.

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Onshore Properties

Onshore proved reserves accounted for approximately 68% of year-end 2012 proved reserves on a Boe basis as compared to 61% of 2011 reserves on a Boe basis, consistent with our strategy of using our offshore cash flow to explore and develop our onshore properties and following the sale of our offshore interest in the Habanero field.

Permian Basin

As of December 31, 2012, we owned approximately 32,962 net acres in the Permian basin, where we are exclusively focused on the Midland sub-basin. Our reserves in the Permian basin represent approximately 67% of our total proved reserves at year-end 2012 as compared to 48% at year-end 2011. Average net production from the Company's Permian basin properties increased 67% to 1,614 Boe/d in 2012 from 967 Boe/d in 2011.

We describe our activities in the Permian basin based on two geographic areas, the southern and northern Midland basin, given their relative stages of development.

The southern portion of our position (located in Texas counties of Crockett, Upton, Midland, Ector, Reagan and Glasscock) represents the vast majority of our current Permian production. We have been pursuing a vertical development program in this area since our entry into the Permian in 2009, drilling 71 gross (63 net) vertical wells over that period. In 2012, we commenced the horizontal drilling of our properties in Upton and Reagan counties, drilling three net wells targeting the Wolfcamp B shale.

Our northern Midland basin position was established in 2012 with the acquisition of 24,328 gross (21,617 net) acres in Borden and Lynn counties. We began our exploration program in Borden county during the second half of 2012, drilling one gross (0.8 net) vertical and two gross (1.8 net) horizontal wells, targeting the Cline and Mississippi lime.

The following table summarizes our wells drilled and completed by area during 2012:

Property	Drilling		Completion	
	Gross	Net	Gross	Net
Southern Midland basin vertical wells	15	10.7	22	16.0
Southern Midland basin horizontal wells	3	2.8	2	2.0
Total	18	13.5	24	18.0

Property	Drilling		Completion	
	Gross	Net	Gross	Net
Northern Midland basin vertical wells	1	0.8	—	—
Northern Midland basin horizontal wells	2	1.8	1	1.0
Total	3	2.6	1	1.0

Other

We own a 69% working interest in a 429 net acre unit of the Haynesville shale natural gas unit located in southern Bossier parish, Louisiana. As of December 31, 2012, our Haynesville shale proved reserves were reduced by 90% compared to year-end 2011 due to low natural gas prices. During 2012, our one producing well produced 3% of our total production on an equivalent basis. Also during 2012, this well was shut-in for a combined 112 days during the fourth quarter of 2011 and the first quarter of 2012 due to well interference from an offsetting well. Production was restored in mid-March 2012 following a successful remediation operation and, as of December 31, 2012, our Haynesville well was producing approximately 751 Mcf of natural gas per day. We currently have no drilling obligations related to this lease position and will wait for natural gas prices to return to a level that would justify capital allocation within our portfolio before recommencing our development of the field.

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Gulf of Mexico Deepwater

Medusa, Mississippi Canyon Blocks 538/582

The Medusa field, in which we own a 15% working interest, is located in 2,235 feet of water approximately 50 miles offshore Louisiana, and currently produces from eight existing wellbores. Murphy Exploration & Production Company ("Murphy"), the operator, owns a 60% working interest and ENI Deepwater, LLC, owns the remaining 25% working interest. Since the field entered production in 2003, cumulative gross volumes have approximated 58 MMBoe.

During 2012, the Medusa field produced 464 MBoe net to Callon from eight wells which accounted for 29% of our total production. Six of the field's wells continue to produce from their initial completions as of December 31, 2012. We project that 1.1 MMBoe of net PDNPs can be accessed by recompletions in the existing wells. These up-hole recompletions in existing wellbores are expected to occur as existing completions deplete to a level that is uneconomic to justify continued production. We anticipate the development of our current net 1.3 MMBoe of PUD reserves in conjunction with a subsea development program to be commenced during 2014.

Gulf of Mexico Shelf

Approximately 4% of our year-end 2012 proved reserves were attributable to the shelf area of the Gulf of Mexico and other properties. We own interests in 14 producing wells in eight oil and natural gas fields in the shelf area of the Gulf of Mexico area. These wells produced 340 MBoe net to our interest in 2012, which accounted for 22% of our total production.

For additional information regarding the Company's properties, including its 2013 capital expenditures program and future development plans, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

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Proved Reserves

Estimates of volumes of proved reserves, net to our interest, at year end 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 volumes are presented in MBoe. For the MBoe computation, 6,000 cubic feet of gas are the equivalent of one barrel of oil.

The following table sets forth certain information about our estimated net proved reserves. All of our proved reserves are located in the continental United States and in federal and state waters in the Gulf of Mexico.

	Years Ended December 31,		
	2012	2011	2010
Proved developed:			
Oil (MBbls)	4,955	5,069	4,503
Natural gas (MMcf)	10,680	11,605	12,715
MBoe	6,735	7,003	6,622
Proved undeveloped:			
Oil (MBbls)	5,825	5,006	3,645
Natural gas (MMcf)	9,073	23,513	20,241
MBoe	7,337	8,925	7,019
Total proved:			
Oil (MBbls)	10,780	10,075	8,149
Natural gas (MMcf)	19,753	35,118	32,957
MBoe	14,072	15,928	13,641
Estimated pre-tax future net cash flows (a)	$592,424	$568,798	$379,448
Pre-tax discounted present value (a) (b)	$250,097	$309,890	$205,532
Standardized measure of discounted future net cash flows(a) (b)	$231,148	$270,357	$198,916

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2012, 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-US GAAP financial measure. The Company believes that Pre-tax discounted present value, while not a financial measure in accordance with US GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of crude 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, 2012 was $231.1 million inclusive of the $18.9 million discounted estimated future income taxes relating to such future net revenues. The natural gas Mcf prices of $4.81 used in the 2012 reserve estimates have been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected crude oil prices of $94.68 used in the 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.

See Note 14 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.

Estimated net proved reserves at December 31, 2012, represented a 12% decrease over 2011 year-end estimated net proved reserves 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 pricing assumptions. These decreases were partially offset by the Company's development of a portion of its Permian basin, on which it added 7 PDP and 19 PUD wells during 2012.

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Proved Undeveloped Reserves ("PUDs")

Annually, the Company reviews its PUDs to ensure appropriate plans exist for development. Except as noted below, reserves are recognized as PUDs only if the Company has plans to convert the PUDs into PDPs within five years of the date they are first recorded as PUDs. The basis for our development plans include the allocation of capital to projects included within our 2013 capital budget and, in subsequent years, the allocation of capital within our long-range business plan. Generally, our 2013 capital budget and our long-range capital plans are 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,		
	2012	2011	2010
Permian basin	6,040	4,861	2,928
Haynesville shale	—	1,730	1,757
Total Onshore PUDs	6,040	6,591	4,685
Medusa	1,297	1,186	1,186
Habanero (a)	—	1,148	1,148
Total Deepwater PUDs	1,297	2,334	2,334
Total PUDs	7,337	8,925	7,019

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

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 our 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.

Our 1,297 MBoe of deepwater PUDs have been classified as PUDs for more than five years, though we expect to develop these PUDs within the next two years. Our decision to classify these reserves as PUDs was primarily based on (1) our ongoing development planning in the area, (2) our historical record of completing development of comparable long-term projects, (3) the amount of time which we have maintained the leases or booked reserves without significant development activities and (4) the extent to which we have followed previously adopted development plans. Our discussions with the field's operator have resulted in the modification of certain development plans for Medusa to drill or sidetrack PUDs within a shorter period of time than originally estimated. The Company expects to drill a new well in 2014 within the Medusa field to access the PUD reserves of 1,297 MBoe. During 2012, the Company did not convert any offshore PUDs to PDPs.

The Company's plans to develop its onshore, Permian basin PUDs as part of a multi-year drilling program, which is expected to be completed on existing acreage within five years of the initial recording of any PUD.

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 30 years of industry experience including 25 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

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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, natural gas and natural gas liquids reserves and work of the 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.

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Production Volumes, Average Sales Prices and Average 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 crude oil and natural gas for the periods indicated.

	Years Ended December 31,		
	2012	2011	2010
	(in thousands, except per unit data)		
Production			
Natural gas and NGLs (Mcf)	3,588	5,081	4,892
Crude oil (MBbl)	977	996	859
Total (MBoe)	1,575	1,843	1,674
Revenues			
Natural gas and NGL sales	$14,149	$26,682	24,639
Crude oil sales	96,584	100,962	65,243
Total revenues	$110,733	$127,644	$89,882
Lease Operating Expenses			
Production costs	$22,981	$17,693	$15,770
Severance/production taxes	2,430	1,826	816
Gathering	349	592	802
Ad Valorem	794	236	324
Total lease operating expenses	$26,554	$20,347	$17,712
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on derivatives) (a)	$3.94	$5.25	$5.04
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) (a)	3.94	5.25	4.91
Crude oil ($/Bbl, including realized gains (losses) on derivatives) (b)	98.86	101.34	75.97
Crude oil ($/Bbl, excluding realized gains (losses) on derivatives) (b)	97.41	101.72	75.97
Operating costs per Boe - Total Consolidated			
Production costs	$14.59	$9.60	$9.61
Severance/production taxes	1.54	0.99	0.49
Gathering	0.22	0.32	0.48
Ad Valorem	0.50	0.13	0.19
Total operating costs per Boe	$16.85	$11.04	$10.77

(a) 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 and deepwater production.

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

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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 and in federal and state waters in the Gulf of Mexico. At December 31, 2012, the Company was in the process of drilling one exploratory well (which is excluded from the table below) and had four wells awaiting fracture stimulation.

	Years ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Crude oil	14	9.70	36	32.77	20	19.37
Natural gas	—	—	—	—	1	0.69
Non-productive	—	—	—	—	—	—
Total	14	9.70	36	32.77	21	20.06
Exploration:						
Crude oil	7	6.20	—	—	—	—
Natural gas	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total	7	6.20	—	—	—	—

Wells drilled within the productive boundaries of statistical plays, such as on our southern Midland basin acreage, have been classified as development wells.

The following table sets forth productive wells as of December 31, 2012:

	Crude Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	103	84.50	10	4.30
Royalty interest	3	0.10	2	0.08
Total	106	84.60	12	4.38

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

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

	Year ended December 31, Production Volumes (MBoe)			% of Total Proved Reserves at 12/31/2012					
Offshore - Gulf of Mexico:	2012	2011	2010	2012		2011		2010	
Medusa	464	641	593	28	%	27	%	33	%
Habanero	134	197	233	—	%	8	%	10	%
Shelf and other	340	551	616	4	%	4	%	7	%
Total offshore:	938	1,389	1,442	32	%	39	%	50	%
Onshore:									
Permian basin	591	353	150	67	%	48	%	33	%
Haynesville shale	46	101	82	1	%	13	%	17	%
Total onshore:	637	454	232	68	%	61	%	50	%

Total	1,575	1,843	1,674	100	%	100	%	100	%

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Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2012.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	1,741	681	233	167	1,974	848
Texas (a)	10,891	8,914	27,236	24,048	38,127	32,962
Federal onshore (b)	—	—	64,963	64,963	64,963	64,963
Federal waters (c)	44,920	17,136	23,715	7,599	68,635	24,735
Total	57,552	26,731	116,147	96,777	173,699	123,508

(a) A portion of our Texas acreage requires continued 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, has approximately six years remaining, and had a carrying value at December 31, 2012 of approximately $2.6 million included in the Company's unevaluated properties balance. The lease requires no drilling activity to hold the acreage, and we continue to monitor the activity of other operators conducting drilling in the area.

(c) The Company's federal waters acreage is held by production.

Title to Properties

The Company believes that the title to its crude 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 typically subject, in one degree or another, 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 both onshore and offshore operations (including sudden and accidental pollution), physical damage to its offshore oil and natural gas properties, aviation liability, auto liability, worker's compensation, employer's liability, and maritime employers liability. The company carries control of well insurance for all offshore wells, though unless contractually bound to do so, the Company does not carry control of well insurance for onshore operations. 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 environmental liability coverage for the effects of pollution on third parties

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arising from its operations. The Company's insurance policies contain high policy limits, and in most cases, deductibles (generally ranging from $0 to $1.5 million) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, 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.

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 ended:

	December 31,					
	2012		2011		2010	
Shell Trading Company	39	%	45	%	44	%
Plains Marketing, L.P.	15	%	17	%	20	%
Enterprise Crude Oil, LLC	32	%	16	%	—	%
Louis Dreyfus Energy Services	2	%	4	%	13	%
Other	12	%	18	%	23	%
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 87 employees as of December 31, 2012, which included 13 petroleum engineers and four petroleum geoscientists. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

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Regulations

General. The oil and natural gas industry is subject to regulation at the federal, state and local level, and some of the laws, rules and regulations that govern our operations carry substantial penalties for non-compliance. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

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 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.

For instance, our OCS leases in federal waters are administered by three Bureaus of the Department of Interior "DOI". In response to concerns that the former MMS revenue-generating and resource development functions were at odds with its safety and environmental regulatory functions, the DOI reorganized the MMS into three separate agencies: the BOEM, to be the resource manager for conventional and renewable energy and mineral resources on the OCS; the BSEE, to promote and enforce safety in offshore energy exploration and production operations; and the ONRR, to collect and distribute royalties, rents, fees and other revenues, including the development of regulations with respect to revenue valuation and collection and enforcement activities. In this “Exploration and Production” section, we refer to actions of one or more of the foregoing agencies as actions of “the DOI Bureaus”.

The DOI Bureaus require compliance with detailed regulations and orders. Lessees must obtain DOI Bureau approval for exploration, exploitation and production plans and applications for permits to drill prior to the commencement of such operations. Since the April 20, 2010 blowout and oil spill at the BP Deepwater Horizon Macondo oil well, the DOI Bureaus have issued numerous rules, Notices to Lessees and other guidance documents augmenting the existing regulations with more stringent safety, engineering and environmental requirements. The DOI Bureaus have also issued a rule requiring that all operators in the OCS formulate detailed Safety and Environmental Management Systems to improve the safety of their operations on the OCS. Current DOI Bureau regulations restrict the flaring or venting of natural gas, and prohibit the flaring of liquid hydrocarbons and oil without prior authorization. The DOI Bureaus are considering whether to require flaring rather than venting, where practical, to reduce the potential effect of greenhouse gas emissions.

DOI Bureau policies concerning the volume of production that a lessee must have to maintain an offshore lease beyond its primary term also are applicable to Callon. Similarly, the DOI Bureaus have promulgated other regulations and Notices to Lessees governing the plugging and abandonment of wells located offshore and the installation and decommissioning of production facilities. To cover the various obligations of lessees on the OCS, the DOI Bureaus generally requires that lessees post bonds, letters of credit, or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. Under some circumstances, the DOI Bureaus may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial conditions and results of operations.

As stated above, the April 20, 2010 blowout and oil spill at the BP Deepwater Horizon oil rig has prompted the federal government to impose heightened regulation of oil and natural gas exploration and production on the OCS. Especially with respect to deepwater operations, the DOI Bureaus have issued rules that are more stringent than the rules issued by the MMS, and have announced their intention to issue additional safety rules and be more scrupulous in implementing existing environmental requirements in the future. Legislation has been introduced in the United States Congress to toughen the regulation of oil and natural gas exploration and production on the OCS. In addition, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, whose members were appointed by President Obama, issued a report proposing, among other things, fundamental reform of the regulation of oil and natural gas exploration and production on the OCS. The tightening of regulation on the OCS could impose

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higher costs on, and render it more difficult to timely obtain regulatory approval of our proposed activities on the OCS, especially as to deepwater projects.

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 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 Regulation. Various federal, state and local laws and regulations concerning the release of contaminants into the environment, including the discharge of contaminants into water and the emission of contaminants into the air, the generation, storage, treatment, transportation and disposal of wastes, and the protection of public health, welfare, and safety, and the environment, including natural resources, affect our exploration, development and production operations, including operations of our processing facilities. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, constructing, operating and abandoning wells. Regulatory requirements relate to, among other things, the handling and disposal of drilling and production waste products, the control of water and air pollution and the removal, investigation, and remediation of petroleum-product contamination. In addition, our operations may require us to obtain permits for, among other things,

- air emissions,
- discharges into surface waters (including wetlands), and
- the construction and operations of underground injection wells or surface pits to treat, re-use or dispose of produced water and other nonhazardous oilfield wastes.

In the event of an unauthorized discharge (e.g., to land or water), emission (e.g., to air) or other activity, we may be liable for, among other things, penalties, costs and damages, and subject to injunctive relief, and we could be required to cleanup or mitigate the environmental impacts of those discharges, emissions or activities. Also, under federal, and certain state, laws, the present and certain past owners and operators of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of hazardous substances into the environment and damage to natural resources caused by such release. The Environmental Protection Agency, state environmental agencies and, in some cases third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions. We therefore could be required to remove or remediate previously disposed wastes and remediate contamination, including contamination in surface water, soil or groundwater, caused by disposal of that waste, irrespective of whether disposal or release were unlawful. We could be responsible for wastes disposed of or released by us or prior owners or operators at properties owned or leased by us or at locations where wastes have been taken for disposal also irrespective of whether disposal or release were authorized. We could also be required to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination.

Federal, and certain state, laws also impose duties and liabilities on certain "responsible parties" related specifically to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. These laws assign liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed under these laws, they are limited. In the event of an oil discharge or substantial threat of discharge, we could be liable for costs and damages.

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The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes thereby increasing the costs of disposal. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

There are federal and certain state laws that impose restrictions on activities adversely affecting the habitat of certain plant and animal species. In the event of an unauthorized impact or taking of a protected species or its habitat, we could be liable for penalties, costs and damages, and subject to injunctive relief, and we could be required to mitigate those impacts. A critical habitat or suitable habitat designation also could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development.

Oil and natural gas exploration and production activities are being subjected to additional regulatory scrutiny under the Clean Air Act (“CAA”). On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both 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 new hydraulically fractured gas wells and also existing gas wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from certain compressors, controllers, dehydrators, storage tanks, natural gas processing plants and other equipment based upon equipment types, locations, and emission thresholds. These rules may require changes to our operations, including the installation of new equipment to control emissions.

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary costs of doing business within the oil and natural gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities. We believe we are in compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Greenhouse Gas (“GHG”) Regulation. Although federal legislation regarding the control of greenhouse gasses, or GHGs, thus far has been unsuccessful, the EPA has moved forward with rulemaking to regulate GHGs as pollutants under the CAA. These GHG regulations may require us to incur increased operating costs and may have an adverse effect on demand for the oil and natural gas we produce.

The EPA, as of January 2, 2011, requires the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs in a multi-step process, with the largest sources first subject to permitting. Those permitting provisions, should they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. On November 30, 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions if the total emissions within a basin exceed 25,000 metric tons CO_2 equivalent per year. Although this rule does not limit the amount of GHGs that can be emitted, it will require us to incur costs to monitor, keep records of, and potentially report GHG emissions associated with our operations if the reporting threshold is reached with production growth.

In addition to 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. The 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.

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Application of the Safe Drinking Water Act to Hydraulic Fracturing. Congress has considered but has not passed legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. A number of state, local and regional regulatory authorities have or are considering hydraulic fracturing regulation. For example, Texas has adopted regulations requiring the disclosure of hydraulic fracturing chemicals. Potential federal as well as existing and potential state regulation could cause us to incur substantial compliance costs, and the requirement could negatively affect our ability to conduct fracturing activities on our assets.

In addition, the EPA has recently been taking actions to assert federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, 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, with final results expected in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming. This study remains subject to review. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and 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. Consequently, these studies and initiatives could spur further legislative or regulatory action regarding hydraulic fracturing or other production operations. Further, the BLM has indicated that it will engage in rulemaking to regulate hydraulic fracturing on federal lands.

Further, EPA has announced an initiative under the Toxic Substances Control Act (“TSCA”) to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

All of the acreage and undeveloped reserves within the Permian basin are subject to hydraulic fracturing procedures as the process is required to economically develop the Wolfberry formation. The hydraulic fracturing process is integral to the Company's overall drilling and completion costs in the Permian basin and represented approximately 34% or $0.8 million of the total drilling/completion costs per vertical well drilled during 2012.

The hydraulic fracturing activity is limited to the oil and natural gas bearing formations, which are found at depths ranging between 6,000 and 12,000 feet from the surface in Midland, Ector and Upton counties, Texas. The Railroad Commission of Texas has defined potable water sources in this area as usable-quality ground water from the surface to a depth of 250 feet for our acreage in Midland and Ector counties and to a depth of 425 feet for our acreage in Upton counties.

The Company diligently reviews best practices and industry standards, and complies with all regulatory requirements in the protection of these potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources.

Based on current drilling techniques, a typical fracturing procedure for a vertical well in the Wolfberry formation uses approximately 1.8 million gallons of fresh water, approximately 1.2 million pounds of sand and other elements including enzymes and guar, a common food additive. Horizontal wells typically use 9.5 million gallons of water and approximately 6.2 million pounds of sand.

In compliance with the law enacted in Texas in June 2011 and regulations adopted in December 2011, the Company will disclose hydraulic fracturing data to the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission chemical registry effective January 2, 2012. This disclosure is required for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment. A copy of the completed form is uploaded into the Chemical Disclosure Registry also known as FracFocus, which is a publically accessible website.

There have not been any incidents, citations or suits related to the Company's hydraulic fracturing activities involving environmental concerns.

The Federal Water Pollution Control Act, also known as the “Clean Water Act” and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S.

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Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and cleanup and response costs.

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.

Mineral Lease 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 interests in numerous federal onshore oil and natural gas leases. 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 Regulations. If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements. Certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the BLM, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, or other appropriate federal, state, or tribal agencies.

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 polices 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 15 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.

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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. 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 Facility;
- the profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and natural gas properties.

Natural gas prices have been depressed recently and have the potential to remain depressed for the next several years, which may have an adverse effect on our financial condition and results of operations. Natural gas prices have been depressed for the last several years as a result of over-supply caused by, among other things, increased drilling in unconventional reservoirs, reduced economic activity associated with a recession and weather conditions. We expect natural gas prices to be depressed during the foreseeable future. Approximately 23% of our estimated net proved reserves at December 31, 2012 are natural gas, and 38% of our production in 2012 was natural gas. A sustained reduction in natural gas prices could have an adverse effect on our results of operations and financial condition.

If oil and natural gas prices decrease or remain depressed for extended periods of time, we may be required to take additional writedowns of the carrying value of our oil and natural gas properties. We may be required to writedown the carrying value of our oil and natural gas properties when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated net proved reserves, increases in our estimates of development costs or if we experience deterioration in our exploration results. 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. We review the carrying value of our properties quarterly, based on the pricing noted above. Once incurred, a writedown of oil and natural gas properties is not reversible at a later date, even if prices increase. See Note 14 to our Consolidated Financial Statements.

Our actual recovery of reserves may substantially differ from our proved reserve estimates. 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. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

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 based on historical performance and expected future operation investment activities;
- Future oil and natural gas prices and quality and locational differences; and
- Future development and operating costs.

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You should not assume that any present value of future net cash flows from our producing reserves contained in this Form 10-K represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2012 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, 2012, approximately 14% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 52% of total proved reserves by volume, and approximately 18% of our PUDs were attributable to our deepwater property. Recovery of undeveloped reserves 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 are able to replace reserves that we have produced, our cash flows and production will decrease over time. The high-rate production characteristics of our Gulf of Mexico properties subject us to high reserve replacement needs. In general, the volume of production from oil and natural gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Our Gulf of Mexico, deepwater properties accounted for approximately 38% of our production which included the Habanero property during 2012 and 28% of our estimated proved reserves at December 31, 2012 excluding the Habanero property. Similarly, our Gulf of Mexico shelf properties accounted for approximately 22% of our production during 2012 and 4% of our estimated proved reserves at December 31, 2012. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices. Without successful exploration or acquisition activities, our reserves, production and revenues will decline.

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 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. The incremental capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores. We cannot assure you that our future exploitation, exploration, development, and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

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. Our industry is cyclical and, from time to time, there is 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.

A significant portion of our production and reserves is concentrated in our deepwater offshore property, and any production problems or inaccuracies in reserve estimates related to this property would adversely impact our business. During 2012, approximately 29% of our daily production came from our Medusa field, which is currently our only deepwater property located in the Gulf of Mexico. In addition, at December 31, 2012, approximately 28% of our total net proved reserves were located within this field. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

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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. During 2012, we purchased 24,328 net acres in the northern portion of the Midland basin, an area that has seen only limited development activity. We expect to conduct substantial exploration of this acreage over the next several years. Although we have been successful in exploration in the past, we cannot assure you that we will continue to increase reserves through exploration or at an acceptable cost. Additionally, we are often uncertain as to the future costs and timing of drilling, completing and producing wells. Our exploration drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- 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;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of our joint working interest owners; and
- changes to governmental regulations.

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. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling, and 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.

We may be 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 business segment or 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.

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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.

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.

There is competition for available oil and natural gas properties. Our competitors include major oil and gas companies, independent oil and gas companies and financial buyers. Some of our competitors may have greater and more diverse resources than we do. High commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties. The increased competition and rising prices for available properties could limit or impede our ability to identify acquisition opportunities that are economic for a company our size and that are necessary to grow our reserves or replace reserves produced.

We do not operate and have limited influence over the operations of our deepwater property. Our lack of control could result in the following:

- the operator may initiate exploration or development at a faster or slower pace than we prefer or that we anticipate in preparing our reserve estimates;
- the operator may propose to drill more wells or build more facilities on a project than we have funds for or that we deem appropriate, which may mean that we are unable to participate in the project or share in the revenues generated by the project even though we paid our share of exploration costs; and
- if an operator refuses to initiate a project, we may be unable to pursue the project.

Any of these events could materially impact the value of our non-operated properties.

Weather, 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;
- hurricanes, storms and other 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.

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If we experience any of these problems, it could affect well bores, platforms, 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.

Offshore operations are also subject to a variety of additional operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for development or leasehold acquisitions, or result in loss of equipment and properties.

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, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and 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.

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;
- the proximity of the natural gas production to natural gas and NGL 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.

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 the Wolfcamp shale, Cline shale, and Mississippian lime 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. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established. 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 writedowns 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 in 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. We experienced Gulf of Mexico production interruption in 2005, 2006, 2007, and 2012 from Hurricanes Katrina, Rita, and Isaac and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance. 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 affect 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 as well as numerous independents, 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.

During 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”). Among other things, the Act requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions); the CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain

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capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivative activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts reduce the availability of derivatives to protect against risks we encounter, restrict our flexibility in conducting trading and hedging activity and increase our exposure to less creditworthy counterparties. 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 and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the 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; by hedging, we may not benefit from price increases. 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 production. Hedging will also prevent us from receiving the full advantage of increases in oil or natural gas prices above the fixed amount specified in the hedge.

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.
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, wilderness areas or coral reefs; 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. We could also be affected by more stringent laws and regulations adopted in the future, including any related 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.

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Climate change legislation or regulations restricting emissions of "greenhouse gasses" could result in increased operating costs and reduced demand for the oil and natural gas we produce. The EPA has adopted its so-called "GHG tailoring rule" that will phase in federal PSD permit requirements for greenhouse gas emissions from new sources and modification of existing sources, federal Title V operating permit requirements for all sources, based upon their potential to emit specific quantities of GHGs. These permitting provisions to the extent applicable to our operations could require us to implement emission controls or other measures to reduce GHG emissions and we could incur additional costs to satisfy those requirements.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published its amendments to the greenhouse gas reporting rule to include 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 greenhouse gas emissions from such facilities is required on an annual basis if the total emissions within a basin exceed 25,000 metric tons CO_2 equivalent per year. We will have to incur costs associated with this monitoring obligation and potentially additional reporting costs if production growth triggers the emission threshold.

In addition, the United States Congress has considered 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 hurricanes and floods), sea levels, 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 affect 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 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. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. A progress report was issued in December 2012, and final results anticipated

in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review. A committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Legislation was introduced before Congress 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 imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized. 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, EPA has announced an initiative 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 is regulated at the federal level, our fracturing activities could become subject to additional

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permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. 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.

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.

ITEM 1B. Unresolved Staff Comments

None.

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.

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PART II.

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

The Company's 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.

			Stock Price	
	2012		High	Low
First quarter	ended	March 31, 2012	$7.95	$5.09
Second quarter	ended	June 30, 2012	6.45	3.80
Third quarter	ended	September 30, 2012	6.55	4.11
Fourth quarter	ended	December 31, 2012	6.36	4.05
	2011			
First quarter	ended	March 31, 2011	$9.36	$5.81
Second quarter	ended	June 30, 2011	8.04	5.93
Third quarter	ended	September 30, 2011	7.73	3.79
Fourth quarter	ended	December 31, 2011	5.99	3.02

As of March 1, 2013 the Company had approximately 3,229 common stockholders of record.

The Company has never paid dividends on its common stock, and intends to retain its cash flow from operations for the future operation and development of its business. In addition, the Company's Credit Facility and the terms of our outstanding debt prohibit the payment of cash dividends on our common stock.

During the fourth quarter of 2012, 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, 2012 (securities amounts are presented in thousands).

	Outstanding Options		
Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	37	$ 13.51	1,669
Equity compensation plans not approved by security holders	30	7.90	—
Total	67	11.82	1,669

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

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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 two 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 compares the yearly percentage change in the cumulative total stockholder return on the Company’s common stock with the cumulative total return of the New York Stock Exchange Market Index and of the Morningstar Group Index (consisting of independent oil and gas drilling and exploration companies) from December 31, 2007, through December 31, 2012. 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.

	For the Year Ended December 31,					
Company/Market/Peer Group	2007	2008	2009	2010	2011	2012
Callon Petroleum Company	$100.00	$15.81	$9.12	$35.99	$30.21	$28.57
NYSE Composite Index	100.00	60.86	78.25	88.89	85.63	99.47
Morningstar Group Index	100.00	39.51	71.28	74.52	64.64	71.97

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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, 2012 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. The information included in this table for the year ended December 31, 2011 include the effects of corrections on the previously reported financial statements, as further discussed in Note 1 to the Consolidated Financial Statements included in Part II, Item 8 of this filing.

	For the year ended December 31,				
	2012	2011	2010	2009	2008
Statement of Operations Data:	(In thousands, except per share amounts)				
Operating revenues:					
Oil and natural gas sales	$110,733	$127,644	$89,882	$101,259	$141,312
Medusa BOEM royalty recoupment (a)	—	—	—	40,886	—
Total operating revenues	$110,733	$127,644	$89,882	$142,145	$141,312
Operating expenses:					
Non-impairment related operating expenses	$100,043	$88,022	$68,703	$68,692	$97,497
Impairment of oil and gas properties (b)	—	—	—	—	485,498
Total operating expenses	$100,043	$88,022	$68,703	$68,692	$582,995
Income (loss) from continuing operations	10,690	39,622	21,179	73,453	(441,683)
Net income (loss) (c)	2,747	106,396	8,386	46,796	(438,893)
Earnings (loss) per share ("EPS"):					
Basic	$0.07	$2.81	$0.29	$2.12	$(20.68)
Diluted	$0.07	$2.76	$0.28	$2.11	$(20.68)
Weighted average number of shares outstanding for Basic EPS	39,522	37,908	28,817	22,072	21,222
Weighted average number of shares outstanding for Diluted EPS	40,337	38,582	29,476	22,200	21,222
Statement of Cash Flows Data:					
Net cash provided by operating activities	$51,290	$79,167	$100,102	$19,698	$89,054
Net cash used in investing activities	(93,703)	(91,511)	(59,738)	(43,189)	(4,511)
Net cash provided by (used in) financing activities	(243)	38,703	(26,252)	10,000	(120,667)
Balance Sheet Data:					
Oil and natural gas properties, net	$269,521	$215,912	$168,868	$130,608	$159,252
Total assets	378,173	369,707	218,326	227,991	266,090
Long-term debt (d)	120,668	125,345	165,504	179,174	272,855
Stockholder' equity (deficit)	205,971	201,202	15,810	(80,854)	(129,804)
Proved Reserves Data:					
Total oil (MMBbls)	10,780	10,075	8,149	6,479	6,027
Total natural gas (MMcf)	19,753	35,118	32,957	19,103	18,652
Total proved reserves (MBoe)	14,072	15,928	13,641	9,663	9,136
Standardized measure	$231,148	$270,357	$198,916	$135,921	$86,305

(a) Following the decisions resulting from several court cases brought by another oil and gas company, the court ruled that the BOEM was not entitled to receive these royalty payments. The amount above reflects royalty recoupments for production from the fields 2003 inception through December 31, 2008, which were accrued at December 31, 2009 and paid by the BOEM during 2010.

(b) In 2008, the Company recorded a $485.5 million impairment of oil and gas properties as a result of the ceiling test. See Notes 2 and 12 to the Consolidated Financial Statements for a description of the relevant accounting policy and the Company's oil and gas properties disclosures, respectively.

(c) 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 11 for additional information.

(d) 2012 and 2011 long-term debt includes a non-cash deferred credit of $13,707 and $18,384, respectively that will be amortized into earnings as a reduction to interest expense over the life of the 13% Senior Notes due 2016. See Note 5 for additional information.

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

General

The following management's discussion and analysis is intended to assist in understanding 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.

We have been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. In 2009, we began to shift our operational focus from exploration in the Gulf of Mexico to building an onshore asset portfolio in order to provide a multi-year, low-risk drilling program in both oil and natural gas basins. This onshore transition has been, and is expected to continue to be, primarily funded by reinvesting the cash flows from our Gulf of Mexico properties including, as previously discussed, the proceeds from the monetization of our interest in the deepwater Habanero field in the fourth quarter of 2012.

Well count information is presented gross unless otherwise indicated.

Overview and Outlook

During 2012, Callon realized net income and fully diluted earnings per share of \$2.7 million and \$0.07, respectively, compared to net income of \$106.4 million and fully diluted earnings per share of \$2.76, respectively for 2011. Net income during 2011 benefited significantly from an income tax benefit of \$69.3 million, that related primarily to the full reversal of a valuation allowance we previously recorded against our deferred tax assets (see Note 11 for additional information). The Company’s earnings, and the drivers of these earnings, are discussed in greater detail within the “Results of Operations” section included below.

During 2012, the Company continued to transition its asset base from primarily offshore to primarily onshore, seeking to replace high volume offshore production with long-lived onshore crude oil production. In addition to building upon its portfolio of unconventional drilling opportunities with a crude oil focus, the Company continued to expand upon its expertise as an onshore operator in the Permian basin while maintaining a strong financial position to facilitate future growth. Significant accomplishments for 2012 include:

- Increased 2012 Permian basin production by 67% to 591 Mboe as compared to 2011,
- Increased 2012 Permian basin proved reserves by 24% to 9.4 MMboe as compared to 2011,
- Increased 2012 Permian basin leasehold position by 246% to 32,962 net acres as compared to 2011,
- Commenced the horizontal development of our East Bloxom field in the southern portion of the Midland basin, with the drilling of two horizontal wells targeting the Wolfcamp B shale. The average initial (24-hour) production rate from these two wells was 801 Boe per day, with an oil composition of 83%,
- Commenced the evaluation of our newly acquired northern Midland acreage position, testing numerous vertical and horizontal development concepts,
- Accelerated offshore cash flows for onshore redeployment with the sale of our interest in the Habanero field for \$39.4 million, and
- Expanded our lending bank group to five institutions and increased our Credit Facility size by \$20.0 million or 44% as compared to December 31, 2011.

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Highlights of our onshore activity and Gulf of Mexico operations include:

Onshore - Permian Basin

We expect that our production and reserve growth initiatives will continue to focus primarily on the Permian basin, in which we own approximately 38,127 gross (32,962 net) acres as of December 31, 2012.

Southern Portion: We currently own approximately 11,345 net acres in the southern portion of the Permian basin, an increase of 19% since year-end 2011. Our current production in the southern Midland basin (Crockett, Ector, Glasscock, Midland, and Upton counties in Texas) is primarily from the Wolfberry play, although we added production volumes from the horizontal development of the Wolfcamp B shale during 2012.

During 2012, we drilled 15 vertical wells and completed 22 vertical wells. As part of this program, we tested deeper target zones below the Atoka in the fourth quarter of 2012. Based on the results of this test, we are currently planning to add these deeper zones to our ongoing vertical Wolfberry-type drilling and completion program at our Pecan Acres and Carpe Diem fields.

In addition to this vertical drilling program, we commenced a horizontal oil shale drilling program at our East Bloxom field in the second quarter of 2012, initially targeting the Wolfcamp B formation. In 2012, we drilled and completed two horizontal wells on this acreage position, each with a lateral length of over 7,100 feet. In the first quarter of 2013, we drilled an additional three horizontal Wolfcamp shale wells at East Bloxom, with two wells targeting the Wolfcamp B shale and one targeting the Wolfcamp A shale.

In order to increase our exposure to horizontal development of the Wolfcamp B shale, we acquired 2,319 gross (1,762 net) acres in southern Reagan county, Texas, which closed on July 5, 2012, and is now referred to as our Taylor Draw field. We finished the drilling of our initial horizontal well, targeting the Wolfcamp B shale, in December 2012, completed the well in February 2013, and are currently evaluating the well results that include some positive indications.

Based on our initial results and the results of other industry participants, we are planning to increase our level of horizontal drilling activity in 2013 in this portion of the basin, drilling a total of 14 wells. Given this level of sustained activity, we are planning on executing these wells from drilling pads using batch completions in an effort to maximize capital efficiency. These development plans are currently expected to be focused on our East Bloxom and Taylor Draw fields.

Northern Portion: We currently own approximately 21,617 net acres in the northern portion of the Permian basin, which includes the 14,653 net acres in Borden county, Texas and an additional 6,964 net acres in Lynn county, Texas. These leasehold positions were acquired during the course of 2012 for a total consideration of $19.4 million, or $896 per net acre. These positions represent our effort to expand our drilling inventory in the Midland basin with exploration upside potential at a reasonable cost of entry.

After completing a 3-D seismic survey on our acreage position, we commenced the drilling of an exploratory vertical well in July 2012, followed by the drilling of two horizontal wells. The first horizontal well was drilled in the Cline shale and was completed in December 2012. The hydrocarbons from this well did not produce in economic quantities and the well was temporarily abandoned in February 2013. We drilled the second horizontal well, targeting the Mississippian lime interval, in November 2012, completed the well in February 2013 and are currently evaluating the well results.

Although the area has experienced a recent increase in drilling activity, the northern Midland basin has had limited drilling activity compared with the southern basin (where our current production is located), which significantly increases the risk associated with successful drilling activities in this area.

In addition to the $29.6 million consideration paid for each of the above referenced leasehold additions, the Company's unevaluated property balance of $68.8 million at December 31, 2012 includes $29.7 million of exploration and facility costs incurred in 2012 on these properties and $9.5 million of other related items. See Note 12 for additional information. Based on the Company's present development plans, the Company expects the majority of the exploration and facility costs will be transferred to evaluated properties during 2013.

Offshore - Deepwater

Our net interest in the Habanero field produced an average of 366 Boe per day for 2012. The field was shut-in for approximately 50 days during the year for scheduled maintenance, and hurricane-related issues. On December 28, 2012, we completed the sale of our interest in the Habanero field to Shell Offshore Inc., a subsidiary of Royal Dutch Shell Plc, for net cash consideration of $39.4 million.

Our remaining deepwater property, our 15% interest in the Medusa field, continues to play a key role in our portfolio. Our net interest in the Medusa field produced an average of 1,268 Boe per day during 2012, approximately 87% being crude oil that receives pricing based on Mars WTI crude. The Medusa platform was shut-in for 28 days during the second quarter of 2012 for planned construction activities on the West Delta 143 oil pipeline through which Medusa's production is transported. Due to Hurricane Isaac, the platform was once again shut-in from August 27, 2012 to September 4, 2012.

We anticipate that the future cash flows from Medusa will continue to contribute to the funding of our onshore activity. In addition, we believe that additional reserve potential exists as part of this project. The operator of the field, Murphy Oil Corporation, has sanctioned a two well subsea development for the Medusa field. One of these wells will be targeting the development of reserves associated with our existing PUD reserves in the T-4B sand with an uphole recomplete to the T-0A and T-0B sand. The remaining well will target probable reserves. We anticipate that the drilling of these wells will begin in the first quarter of 2014.

Offshore – Shelf & Other Properties

We own interests in 14 producing wells in eight crude oil and natural gas fields in the shelf area of the Gulf of Mexico. These wells produced 340 MBoe net to our interest in 2012, which accounted for 22% of our total production. Production from the East Cameron Block 257 field, which contributed an average of 175 Boe per day of production prior to being shut-in in November 2011, is expected to recommence once the Stingray Pipeline is brought back online. The restart of flows on the pipeline is currently anticipated to occur in the second quarter of 2013.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Cash and cash equivalents decreased by $42.7 million during 2012 to $1.1 million compared to $43.8 million at December 31, 2011. The decrease in our cash balance is primarily attributable to 2012 capital expenditures of $133.3 million, representing a $33.1 million or 33% increase over the amount spent during the same period in 2011. While at December 31, 2012, our Balance Sheet reflects a working capital deficiency of $18.6 million, which is reflective of our current capital investment-driven growth strategy within our Permian properties, we believe that as discussed below our operating cash flows combined with the borrowing availability under our Credit Facility provides the liquidity necessary to meet our operational cashflow needs.

Senior Secured Credit Facility (the "Credit Facility")

On June 20, 2012, Regions Bank increased the Company's Credit Facility to $200 million with an associated borrowing base under the Credit Facility of $60 million and a maturity of July 31, 2014. Subsequently and in October 2012, the Credit Facility was further amended to increase the borrowing base to $80 million, extend the maturity to March 15, 2016 and add Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Regions Bank continues to serve as Administrative Agent for the Credit Facility.

As of December 31, 2012 the borrowing base was revised to $65 million following the sale of our interest in the deepwater Habanero field. Proceeds from the sale, net cash consideration of $39.4 million after customary purchase price adjustments, were used to reduce outstanding borrowings on our Credit Facility. The borrowing base will be redetermined as scheduled in the first quarter of 2013 based upon the evaluation of year-end proved reserves.

Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The Credit Facility is secured by mortgages covering the Company's major producing fields.

As of December 31, 2012, the balance outstanding under the Credit Facility was $10.0 million with a weighted average interest rate on the Credit Facility of 2.72% , calculated as the London Interbank Offered Rate (“LIBOR”) plus a tiered rate ranging from 2.5% to 3.0%, which is based on utilization of the Credit Facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. As of March 13, 2013 , the balance outstanding on the Credit Facility was $25 million as the Company drew an additional $15 million in support of the Company's ongoing capital development program.

Senior Notes due 2016

At December 31, 2012, following a $10 million principal redemption in June 2012, we had approximately $97 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly.

2013 Capital Expenditures

For 2013, we designed a flexible capital spending program, which we plan to fund from cash on hand and cash flows from operations in addition to borrowings under our Credit Facility. However, depending on macroeconomic conditions or the Company's operational results, our capital budget may be adjusted up or down during the year.

Our 2013 capital budget has been established at $125.0 million with over 90% of our budgeted operating expenditures (including drilling, completion, infrastructure, and plugging and abandonment) allocated to our Midland basin operations.. The 15% decrease in total capital from 2011 reflects our primary focus on drilling and completion activities in the Permian basin and reduced emphasis on acreage acquisitions that were budgeted in 2012 to expand the Company's presence in the basin. Our budget includes further exploration and development of our Permian basin properties with plans to complete approximately 26 gross wells including 14 horizontal wells and 12 vertical wells.
Components of the 2013 capital budget include (in millions):

Midland basin	$97
Gulf of Mexico	10
Total projected operations budget	107
Capitalized general and administrative costs	14
Capitalized interest and other	4
Total projected capital expenditures budget	$125

Our total liquidity at December 31, 2012 was $56.1 million, including $1.1 million of cash available and $55.0 million of availability under our Credit Facility. We believe that this liquidity position, combined with our expected operating cash flow based on current commodity prices and forecasted production, will be adequate to meet our forecasted capital expenditures, interest payments, and operating requirements for 2013.

The following table includes the Company's contractual obligations and purchase commitments as of December 31, 2012, at which date the Company had no product delivery commitments:

(amounts in thousands)	Payments due by Period				
	Total	< 1 Year	Years 2 - 3	Years 4 - 5	>5 Years
13% Senior Notes	$96,961	$—	$—	$96,961	$—
Office space lease commitments	3,012	384	785	719	1,124
Drilling rig leases and related (a)	11,512	9,235	2,277	—	—
Other	40	13	27	—	—
Total	$111,525	$9,632	$3,089	$97,680	$1,124

(a) The agreement includes early termination provisions that would reduce the minimum rentals under the agreement, assuming the lessor is unable to re-charter the rig and staffing personnel to another lessee, as follows: <1 year of $5.8 million and 2-3 years of $1.4 million.

Summary cash flow information is provided as follows:

Operating Activities. For the year ended December 31, 2012, net cash provided by operating activities was $51.3 million, compared to $79.2 million for the same period in 2011. The decrease relates primarily to lower revenues from a 2% decrease in crude oil production, a 29% decrease in natural gas production and a 31% increase in lease operating expenses, partially offset by a 2% increase in the average sales price on an equivalent basis. Production and realized prices are discussed below in Results of Operations.

Investing Activities. For the year ended December 31, 2012, net cash used in investing activities was $93.7 million as compared to $91.5 million for the same period in 2011. The net $2.2 million increase in cash used in investing activities is primarily attributable to a $33.1 million increase in capital expenditures related to development activity on our Permian basin acreage and $2.1 million for producing property acquisitions. These expenditures were largely offset by a $32.3 million year-over-year increase in proceeds received for the sale of certain mineral interests including the late 2012 sale of our interest in the deepwater Habanero field discussed below and in Note 12 to the financial statements. The $33.1 million increase in capital expenditures includes the acquisition of additional acreage in Borden and Lynn counties located in the northern Midland basin, additional acreage in Reagan county in the southern Midland basin and costs associated with the horizontal drilling activity.

Financing Activities . For the year ended December 31, 2012, net cash used in financing activities was $0.2 million compared to cash provided by financing activities of $38.7 million during the same period of 2011. Net cash used for 2012 financing activities included a net $10 million draw on our Credit Facility offset by the $10.2 million redemption of Senior Notes. Net cash provided by 2011 financing activities included $73.8 million of net proceeds from an equity offering offset by approximately $35.1 million used to redeem a $31 million principal portion of our outstanding 13% Senior Notes and to pay the $4.0 million call premium and other redemption expenses.

Income Taxes

Prior to 2012, we carried a full valuation allowance against our net deferred tax asset. The income tax benefit of $69.3 million in 2011 resulted primarily from the reversal of the valuation allowance established in 2008 against our net deferred tax assets. As a result of reporting net income from 2009 to 2011, we achieved income on an aggregate basis for the three-year period ended December 31, 2011. Additionally we expect to generate sufficient taxable income necessary to fully utilize all of the deferred tax assets prior to their expiration. Consequently, we reversed the $69.3 million valuation allowance at December 31, 2011. For additional information, see Note 11 to the Consolidated Financial Statements.

Global Settlement with Joint Interest Partner

During the second quarter of 2011, we entered into a final project wind-down agreement with a former joint interest partner in a deepwater project. The agreement provided for the extinguishment of all existing agreements and commitments between the parties as it relates to the past development of the deepwater project. The agreement also included a formal extinguishment of the non-recourse credit agreement between the parties and the assignment to us of the joint interest partner's 50% rights to the remaining project assets, which included primarily the unsold, residual equipment and all engineering data. For additional information regarding the settlement, please refer to Note 3 included in Item II, Part 8 of this filing.

Results of Operations

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

	For the year ended December 31,						
	2012	2011	Change	% Change	2010	Change	% Change
Net production:							
Crude oil (MBbls)	977	996	(19)	(2)%	859	137	16 %
Natural gas (MMcf)	3,588	5,081	(1,493)	(29)%	4,892	189	4 %
Total production (MBoe)	1,575	1,843	(268)	(15)%	1,674	169	10 %
Average daily production (Boe)	4,303	5,049	(746)	(15)%	4,587	462	10 %
Average realized sales price (see below):							
Crude oil (Bbl)	$98.86	$101.34	$(2.48)	(2)%	$75.97	$25.37	33 %
Natural gas (Mcf)	3.94	5.25	(1.31)	(25)%	5.04	0.21	4 %
Total (Boe)	70.31	69.26	1.05	2 %	53.69	15.57	29 %
Crude oil and natural gas revenues (in thousands):							
Crude oil revenue	$96,584	$100,962	$(4,378)	(4)%	$65,243	$35,719	55 %
Natural gas revenue	14,149	26,682	(12,533)	(47)%	24,639	2,043	8 %
Total	$110,733	$127,644	$(16,911)	(13)%	$89,882	$37,762	42 %
Additional per Boe data:							
Sales price	$70.31	$69.26	$1.05	2 %	$53.69	$15.57	29 %
Lease operating expense	(16.86)	(11.04)	(5.82)	(53)%	(10.58)	(0.46)	4 %
Operating margin	$53.45	$58.22	$(4.77)	(8)%	$43.11	$15.11	35 %

Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil and Mcf of natural gas:

Average NYMEX oil price ($/Bbl)	$94.19	$95.14	$(0.95)	(1)%	$79.52	$15.62	20 %
Basis differential and quality adjustments (a)	3.97	7.58	(3.61)	(48)%	(2.39)	9.97	(417)%
Transportation	(0.75)	(1.00)	0.25	25 %	(1.16)	0.16	(14)%
Hedging (b)	1.45	(0.38)	1.83	482 %	—	(0.38)	100 %
Average realized oil price ($/Bbl)	$98.86	$101.34	$(2.48)	(2)%	$75.97	$25.37	33 %
Average NYMEX natural gas price ($/Mcf)	$2.82	$4.03	$(1.21)	(30)%	$4.40	$(0.37)	(8)%
Basis differential and quality adjustments (c)	1.12	1.22	(0.10)	(8)%	0.51	0.71	139 %
Hedging (b)	—	—	—	n/a	0.13	(0.13)	(100)%
Average realized natural gas price ($/Mcf)	$3.94	$5.25	$(1.31)	(25)%	$5.04	$0.21	4 %

(a)

Crude oil prices for production from our two deepwater fields include a premium over NYMEX pricing based on Mars WTI differential for Medusa production and Argus Bonita WTI differential for Habanero production.

(b) As discussed in Note 6, the Company discontinued hedge accounting beginning with derivative contracts executed on January 1, 2012. Consequently, the realized portion of derivative contracts is now included in the statement of operations within Gain on derivative contracts. The amounts reported above reflect the realized portion of derivative contracts designated as cash flow hedges.

(c) 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 and deepwater production.

Revenues

The following tables are intended to reconcile the change in oil, natural gas and total revenue by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program (in thousands):

	Oil	Natural Gas	Total
Revenues for the year ended December 31, 2009	$73,842	$27,417	$101,259
Volume decrease	(11,164)	(4,050)	(15,214)
Price increase	2,556	649	3,205
Impact of hedges increase	9	623	632
Net decrease during the year	(8,599)	(2,778)	(11,377)
Revenues for the year ended December 31, 2010	$65,243	$24,639	$89,882
Volume increase	10,406	952	11,358
Price increase	25,688	1,091	26,779
Impact of hedges decrease	(375)	—	(375)
Net increase during the year	35,719	2,043	37,762
Revenues for the year ended December 31, 2011	$100,962	$26,682	$127,644
Volume decrease	(1,926)	(7,840)	(9,766)
Price decrease	(3,872)	(4,693)	(8,565)
Impact of hedges increase	1,420	—	1,420
Net decrease during the year	(4,378)	(12,533)	(16,911)
Revenues for the year ended December 31, 2012	$96,584	$14,149	$110,733

Crude Oil Revenue

For the year ended December 31, 2012, crude oil revenues of $96.6 million decreased $4.4 million or 4% compared to revenues of $101.0 million for the year ended December 31, 2011. A decrease in commodity prices and production resulted in decreased oil revenue. The average price realized decreased 2% to $98.86 per barrel compared to $101.34 for the same period of 2011. Similarly, production decreased by 2% to 977 MBbls compared to 996 MBbls during the same period in 2011. Crude oil prices for production from our two deepwater fields are adjusted and reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production and Bonita WTI differential for Habanero production. Production decreases relate primarily to the down-time at the Habanero and Medusa fields and the normal and expected declines from our other offshore properties. These production declines were offset by production from our new Permian wells, 22 vertical and two horizontal, brought onto production during 2012.

For the year ended December 31, 2011, crude oil revenues of $101.0 million increased $35.7 million or 55% compared to revenues of $65.2 million for the year ended December 31, 2010. An increase in commodity prices and production resulted in increased crude oil revenue. The average price realized increased 33% to $101.34 per barrel compared to $75.97 for the same period of 2010. Similarly, production increased by 16% to 996 MBbls compared to 859 MBbls during the same period in 2010. Crude oil prices for production from our two deepwater fields are adjusted and reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production and Bonita WTI differential for Habanero production. Production increases relate primarily to progress in developing our Permian basin properties and a successful recompletion at our Medusa field, partially offset by the downtime experienced at our deepwater fields and due to normal and expected declines in our other properties.

Natural Gas Revenue

For the year ended December 31, 2012, natural gas revenues of $14.1 million represented a decrease of 47% or $12.5 million when compared to natural gas revenues of $26.7 million for the year ended December 31, 2011. Natural gas production decreased 29%, driven primarily by down time at our Haynesville well, which was shut-in for 70 days during the first quarter of 2012 due to well interference from an offsetting well, and due to down time at our East Cameron 257 well, which was suspended in the fourth quarter of 2011 due to a natural gas leak in an upstream section of the Stingray Pipeline that transports production volumes from the field. Production from our East Cameron 257 well is expected to resume once the pipeline is brought back online during the second quarter of 2013. Also contributing to the decline was the previously discussed down-time at our Habanero and Medusa fields and normal and expected declines in natural gas production from our offshore and Haynesville wells. In addition to production decreases, the average realized price decreased 25% to $3.94 per Mcf compared to an average realized price of $5.25 per Mcf in 2011. Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream, primarily from our Permian basin and deepwater production.

For the year ended December 31, 2011, natural gas revenues of $26.7 million represented an increase of 8% or $2.0 million when compared to natural gas revenues of $24.6 million for the year ended December 31, 2010. Natural gas production increased 4%, primarily driven by production from our Haynesville Shale natural gas well, which was placed on production during September 2010, and due to down time at our East Cameron #2 field, which was shut-in during the first quarter of 2010 for repairs to the host facility and did not return to production until December 2010. In addition to production increases, the average realized price increased 4% to $5.25 per Mcf compared to an average realized price of $5.04 per Mcf in 2010. Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream, primarily from our Permian basin and deepwater production. Offsetting the increases in production are normal and expected declines in production from our other natural gas properties and a 35-day shut-in, as of December 31, 2011, of our Haynesville well due to interference caused by an offsetting well. The Haynesville well returned to production in mid-March 2012.

Operating Expenses

	For the year ended December 31,							
					Total Change		Boe Change	
	2012	Per Boe	2011	Per Boe	$	%	$	%
Lease operating expenses	$26,554	$16.86	$20,347	$11.04	$6,207	31 %	$5.82	53 %
Depreciation, depletion and amortization	49,701	31.56	48,701	26.42	1,000	2 %	5.14	19 %
General and administrative	20,358	12.93	16,636	9.03	3,722	22 %	3.9	43 %
Accretion expense	2,253	1.43	2,338	1.27	(85)	(4)%	0.16	13 %
Impairment of other property and equipment (See Note 3)	1,177	0.75	—	—	1,177	100 %	0.75	100 %
Total operating expenses	$100,043		$88,022					

	For the year ended December 31,							
					Total Change		Boe Change	
	2011	Per Boe	2010	Per Boe	$	%	$	%
Lease operating expenses	$20,347	$11.04	$17,712	$10.58	2,635	15 %	$0.46	4 %
Depreciation, depletion and amortization	48,701	26.42	31,805	19.00	16,896	53 %	7.42	39 %
General and administrative	16,636	9.03	16,507	9.86	129	1 %	(0.83)	(8)%
Accretion expense	2,338	1.27	2,446	1.46	(108)	(4)%	(0.19)	(13)%
Acquisition expense	—	—	233	0.14	(233)	(100)%	(0.14)	(100)%
Total operating expenses	$88,022		$68,703					

Lease Operating Expenses

For the year ended December 31, 2012, lease operating expenses ("LOE") of $26.6 million increased 31% or $6.2 million compared to $20.3 million for the year ended December 31, 2011. The increase was primarily due to $4.2 million in costs related to significant growth in the number of wells now producing in our Permian basin properties and $3.3 million associated with the remediation work on the Haynesville well. These increases were partially offset by a $1.3 million decline in LOE for our deepwater properties due to lower throughput charges as a result of reduced production volumes discussed previously.

For the year ended December 31, 2011, lease operating expenses ("LOE") of $20.3 million increased by 15% or $2.6 million compared to $17.7 million for the year ended December 31, 2010. The significant growth in the number of wells now producing in our Permian basin properties and our Haynesville Shale well increased total LOE approximately $3.6 million , or $1.95 on a per Boe basis, compared to the corresponding period of 2010. Additionally, total LOE increased approximately $0.5 million related to Medusa Spar maintenance work, the increased production from the Medusa A6 well following the well recompletion, and increased $0.8 million due to processing fees at our East Cameron #2 well, which resumed production in December 2010 after being shut-in for repairs on the host facility during the first quarter of 2010. Partially offsetting these increases was a mix of lower LOE related primarily to our shelf properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") for the year ended December 31, 2012 increased 19% per Boe to $31.56 per Boe compared to $26.42 per Boe for the year ended December 31, 2011. The prior period DD&A rates were effectively reduced by the impact of a $486 million 2008 impairment charge following a ceiling test writedown. This significant oil and natural gas property impairment charge resulted in a lower, prospective DD&A rate for the then existing reserves. Increases in the DD&A rate subsequent to that impairment are attributable to our planned exploration and development expenditures related to our onshore reserve development including the ongoing onshore development cost increases in the Permian basin area. We currently estimate that a normalized DD&A rate for our properties will approximate $36.00 per Boe.

Depreciation, depletion and amortization (“DD&A”) for the year ended December 31, 2011 increased 39% per Boe to $26.42 per Boe compared to $19.00 per Boe for the year ended December 31, 2010. Onshore development cost increases account for nearly all of the increase.

General and Administrative, net of amounts capitalized

For the year ended December 31, 2012, general and administrative (“G&A”) expenses, net of amounts capitalized, increased $3.7 million or 22% to $20.4 million from $16.6 million for the same period of 2011. The increase is due mainly to $1.6 million in costs for non-recurring employee-related expenses including early retirement and severance expense for which we had no expense during the same period of 2011. Additionally, we incurred an increase in non-cash charges of $1.2 million related to incentive compensation share-based instruments awarded during 2012. The remaining increase relates primarily to higher compensation-related expenses including the costs associated with employing staff to support our onshore growth and 100% operated Permian production, as well as relocation and related costs.

For the year ended December 31, 2011, G&A expenses of $16.6 million, net of amounts capitalized, was relatively flat compared to $16.5 million for the year ended 2010.

Accretion Expense

Accretion expense related to our asset retirement obligation decreased 4% for the year ended December 31, 2012 compared to the same periods of 2011. Accretion expense correlates directionally with the Company's asset retirement obligation (“ARO”). At December 31, 2012, our ARO of $13.3 million was lower than the $13.9 million ARO at December 31, 2011. See Note 13 for additional information regarding the Company's ARO.

For the year ended December 31, 2011, accretion expense decreased 4% for the year ended December 31, 2011 compared to the same periods of 2010. The Company's accretion expense decreases as its ARO decreases. At December 31, 2011, our ARO of $13.9 million was lower than the $15.9 million ARO at December 31, 2010. See Note 13 for additional information regarding the Company's ARO.

Impairment of Other Property and Equipment

During 2012, the Company recorded a write-down of the value of certain assets acquired in 2011 as part of a settlement reached with a former joint interest partner on a deepwater project. For information concerning the impairment of these assets, which are currently classified as available for sale, please see Note 3 to the Consolidated Financial Statements.

Other (Income) Expense

	For the year ended December 31,						
	2012	2011	$ Change	% Change	2010	$ Change	% Change
Interest expense	$9,108	$11,717	$(2,609)	(22)%	$13,312	$(1,595)	(12)%
(Gain) loss on early extinguishment of debt	(1,366)	(1,942)	576	30 %	339	(2,281)	(673)%
Gain on acquired assets (See Note 3)	—	(5,041)	5,041	100 %	—	(5,041)	(100)%
Gain on derivative contracts	(1,717)	—	(1,717)	(100)%	—	—	— %
Other (income) expense	(79)	(1,426)	1,347	94 %	(257)	(1,169)	(455)%
Total other expenses,net	$5,946	$3,308			$13,394		
Income tax expense (benefit)	$2,223	$(69,283)	$71,506	103 %	$(174)	$(69,109)	(39,718)%
Equity in earnings of Medusa Spar LLC	226	799	(573)	(72)%	427	372	87 %

Interest Expense

Interest expense on Callon's debt obligations decreased 22% to $9.1 million for the year ended December 31, 2012 compared to $11.7 million for the same period of 2011. The decrease relates primarily to the redemption of $10 million principal of 13% Senior Notes during June 2012 in addition to a $1.5 million increase in capitalized interest compared to 2011, partially offset by interest expense related to increased borrowings under our Credit Facility and decreases in the deferred credit amortization. The increase in capitalized interest relates to a higher balance year-over-year in average unevaluated oil and natural gas properties following the purchase of additional unevaluated acreage with exploration costs in the Permian basin.

Interest expense on Callon's debt obligations decreased 12% to $11.7 million for the year ended December 31, 2011 compared to $13.3 million for the same period of 2010. The decrease relates primarily to the redemption of $31 million principal of 13% Senior Notes during March 2011. This early redemption reduced interest expense by approximately $3.2 million for the current year compared to 2010. Additionally, 2010 interest expense included approximately $0.5 million related to the remaining outstanding $16.1 million of 9.75% Senior Notes, which were redeemed on April 30, 2010 and were therefore not included in 2011 interest expense. Offsetting these declines in interest expense is a $1.4 million drop in capitalized interest in 2011 compared to 2010, and relates to a lower balance year-over-year in average unevaluated oil and natural gas properties following the transfer to evaluated earlier in 2011 of certain leases, primarily offshore, that the Company elected not to renew. Further offsetting the declines discussed above are slight decreases in the deferred credit amortization recorded in 2011 compared to 2010.

(Gain) Loss on Early Extinguishment of Debt

During June 2012, the Company redeemed $10 million of its Senior Notes with a carrying value of $11.6 million , including $1.6 million of the Notes’ deferred credit, in exchange for $10.2 million , comprised of the $10 million principal of the Notes and $0.2 million of redemption expenses, which resulted in a $1.4 million net gain on the early extinguishment of debt.

During March 2011, using a portion of the proceeds from the Company's February 2011 equity offering, the Company redeemed 13% Senior Notes with a carrying value of $37 million, including $6.0 million of the Notes' deferred credit, in exchange for $35.1 million, comprised of the $31 million principal of the notes, the $4.0 million call premium and miscellaneous redemption expenses, which resulted in a $1.9 million net gain on the early extinguishment of debt.

Gain on Acquired Assets

During 2011 and related to the 2012 activity mentioned above, we entered into a settlement with a former deepwater joint interest partner, which included the transfer of certain assets and liabilities to Callon with estimated net fair values of $8.7 million. The assets acquired consisted primarily of the surplus project equipment while the liabilities assumed consisted of deferred tax liabilities associated with the basis difference of the equipment. The adjusted fair market value of the net assets acquired was recorded during 2011 as a $5.0 million gain and a $3.7 million adjustment to our full cost pool of oil and gas properties. The gain recognition was required as a result of our acquiring the joint interest partner's former share of the assets, and the full cost pool adjustment was required to reflect our share of the assets held prior to the deconsolidation of a related subsidiary in 2010. See Note 3 for additional information concerning the gain on acquired assets.

Gain on Derivative Contracts

As discussed in Note 6 and beginning with derivative contracts executed in 2012, the Company elected to no longer designate its derivative contracts as accounting hedges. For the year ended December 31, 2012, unrealized losses and gains on mark-to-market derivative instruments, net were $1.7 million gain, compared to none in 2011 when all derivative contracts were designated as hedges for accounting purposes. See Notes 6 and 7 for disclosures related to derivative instruments including their composition and valuation.

Income Tax Expense (Benefit)

The income tax expense of $2.2 million in 2012 resulted primarily from pre-tax income earnings of $4.7 million. See Note 11 for a discussion of our effective tax rate.

Prior to 2012, we carried a full valuation allowance against our net deferred tax asset. The income tax benefit of $69.3 million in 2011 resulted primarily from the reversal of the valuation allowance established in 2008 against our net deferred tax assets. As a result of reporting net income from 2009 to 2011, we achieved income on an aggregate basis for the three-year period ended December 31, 2011. Additionally we expect to generate sufficient taxable income necessary to fully utilize all of the deferred tax assets prior to their expiration. Consequently, we reversed the $69.3 million valuation allowance at December 31, 2011. For additional information, see Note 11 to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements

The Company holds a 10% ownership interest in Medusa Spar LLC ("LLC"), which is accounted for under the equity method of accounting for investments. The LLC owns a 75% undivided ownership interest in the deepwater spar production facilities at the Company's Medusa field in the Gulf of Mexico. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is 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 Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy Oil Corporation.

Summary of Significant Accounting Policies and Critical Accounting Estimates

Property and Equipment

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 our proved 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 depletion by using the depletable base, 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 crude 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 crude 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 crude 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, the properties are sold or the Company 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 Mcfe produced during the period, the Company records a depletion 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 calculate 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 crude 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 crude oil and natural gas properties exceed the estimated discounted (at 10%) future net cash flows from proved reserves, the Company is required to write-down the value of its crude 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 and include consideration of existing cash flow hedges. Given the volatility of crude oil and natural gas prices, it is reasonably possible that the Company’s estimates of discounted future net cash flows from proved crude oil and natural gas reserves could change in the near term. If crude oil and natural gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of crude oil and natural gas properties could occur in the future. See Notes 2 and 12 for additional information regarding the Company's crude oil and natural gas properties.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows

Estimates of quantities of proved crude 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 crude oil and natural gas production in the future. Crude oil and natural gas prices are volatile, but we are required to assume that they remain constant. In general, higher crude 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. Increases in costs will reduce estimated crude 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.

In addition, the process of estimating proved crude 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 crude oil and natural gas prices under "Risk Factors."

Sales of crude 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 excluded from amortization." Unproved property costs are transferred to the depletable base when wells are completed on the properties or the properties are sold. In addition, the Company is required to determine whether its unproved properties are impaired and, if so, include the costs of such properties in the depletable base. The Company determines whether an unproved 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 its 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 obligation and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 13 for additional information.

Derivatives

To manage crude 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% 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.

Beginning in 2012, we elected to no longer designate derivative contracts executed after January 1, 2012 as accounting hedges under FASB ASC 815-20-25. As such and beginning with derivative contracts executed during 2012, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market through earnings at the end of each period. Realized gains (losses) related to cash settlements on these contracts are recorded in the Statement of Operations as an increase or decrease in crude oil and natural gas sales. Unrealized gains (losses) related to our derivative contracts not designated as accounting hedges are recorded in the Statement of Operations as an increase or decrease in Unrealized gains (losses) on mark-to-market derivative instruments.

Derivative contracts that existed at and prior to December 31, 2011 were accounted for as cash flow hedges, and were recorded at fair market value on its 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 are 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 crude oil and natural gas prices). See Note 11 for additional information regarding Income Taxes.

Recent Accounting Standards

Various accounting standards and interpretations were issued in 2012 with effective dates subsequent to December 31, 2012. We have evaluated the recently issued accounting pronouncements that are effective in 2013 and believe that none of them will have a material effect on our financial position, results of operations or cash flows when adopted. For a discussion of recently issued accounting standards, see Note 2 to the Consolidated Financial Statements.

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ITEM 7A. Quantitative and Qualitative Disclosures about Market Risks

Commodity Price Risk

The Company’s revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil and natural gas, which have historically been very volatile due to unpredictable events such as economical growth or retraction, weather and climate, changes in supply and government actions. Crude oil and natural gas price declines and volatility could adversely affect the Company’s revenues, cash flows and profitability. Price volatility is expected to continue. Using the Company's annual sales volumes for 2012, excluding the effects of the Company’s hedging program, a 10% decline in the NYMEX price of crude oil and natural gas would have reduced our revenues by approximately $9.1 million and $1.3 million, respectively.

While the Company does not enter into derivative transactions for speculative purposes, in order to limit its exposure to this risk, the Company sometimes utilizes price "collars," swaps, puts and other structures to reduce the risk of changes in crude oil and natural gas prices. Under a collar arrangements, no payments are due by either party as long as the market price is above the floor price and below the ceiling price set in the collar. If the price falls below the floor, the counterparty to the collar pays the difference to Callon, and if the price rises above the ceiling, Callon pays the difference to the counterparty. Fixed price “swaps” reduce the Company's exposure to decreases in commodity prices, while simultaneously limiting the benefit the Company might otherwise have received from any increases in commodity prices. The Company’s derivatives policy also allows Callon to, at its discretion, purchase or sale “puts.” Purchased "puts" reduce the Company's exposure to decreases in prices of the hedged commodity while allowing realization of the full benefit from any increases those prices. If the commodity price falls below the "put" price, the counter-party pays the difference to Callon. Conversely, sold "puts" expose the Company to risk whereby Callon would pay its counter-party if prices fall below the "put" price. See Note 6 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2012.

Interest Rate Risk

On December 31, 2012, the majority of the Company's debt consisted of its fixed-rate 13% Senior Notes. However, the Company’s Credit Facility with Regions Bank includes a variable interest rate, and as such fluctuates based on short-term interest rates. Although the Company had $10 million borrowings outstanding at December 31, 2012 under its Credit Facility, were the Company to fully draw its available $65 million borrowing base at the beginning of the year, a 100 basis point change in the variable interest rate would increase the Company’s annual interest expense by $0.65 million. For additional information, see Note 5 to the Consolidated Financial Statements additional information regarding the Company’s Credit Facility and other borrowings at December 31, 2012.

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ITEM 8. Financial Statements and Supplementary Data

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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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2013, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 14, 2013

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CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December, 31 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$1,139	$43,795
Accounts receivable	15,608	15,181
Fair market value of derivatives	1,674	2,499
Other current assets	1,502	1,601
Total current assets	19,923	63,076
Crude oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,497,010	1,421,640
Less accumulated depreciation, depletion and amortization	(1,296,265)	(1,208,331)
Net oil and natural gas properties	200,745	213,309
Unevaluated properties excluded from amortization	68,776	2,603
Total oil and natural gas properties	269,521	215,912
Other property and equipment, net	10,058	10,512
Restricted investments	3,798	3,790
Investment in Medusa Spar LLC	8,568	9,956
Deferred tax asset	64,383	65,743
Other assets, net	1,922	718
Total assets	$378,173	$369,707
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$36,016	$26,057
Asset retirement obligations	2,336	1,260
Fair market value of derivatives	125	—
Total current liabilities	38,477	27,317
13% Senior Notes:		
Principal outstanding	96,961	106,961
Deferred credit, net of accumulated amortization of $17,800 and $13,123, respectively	13,707	18,384
Total 13% Senior Notes	110,668	125,345
Senior secured revolving credit facility	10,000	—
Asset retirement obligations	10,965	12,678
Other long-term liabilities	2,092	3,165
Total liabilities	172,202	168,505
Stockholders' equity:		
Preferred Stock, $.01 par value, 2,500,000 shares authorized;	—	—
Common Stock, $.01 par value, 60,000,000 shares authorized; 39,800,548 and 39,398,416 shares outstanding at December 31, 2012 and 2011, respectively	398	394
Capital in excess of par value	328,116	324,474
Other comprehensive income	—	1,624
Retained deficit	(122,543)	(125,290)
Total stockholders' equity	205,971	201,202

Total liabilities and stockholders' equity	$378,173	$369,707

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the year ended December 31, 2012	2011	2010
Operating revenues:			
Crude oil sales	$96,584	$100,962	$65,243
Natural gas sales	14,149	26,682	24,639
Total operating revenues	110,733	127,644	89,882
Operating expenses:			
Lease operating expenses	26,554	20,347	17,712
Depreciation, depletion and amortization	49,701	48,701	31,805
General and administrative	20,358	16,636	16,507
Accretion expense	2,253	2,338	2,446
Acquisition expense	—	—	233
Impairment of other property and equipment (See Note 3)	1,177	—	—
Total operating expenses	100,043	88,022	68,703
Income from operations	10,690	39,622	21,179
Other (income) expenses:			
Interest expense	9,108	11,717	13,312
(Gain) loss on early extinguishment of debt	(1,366)	(1,942)	339
Gain on acquired assets (See Note 3)	—	(5,041)	—
Gain on derivative contracts	(1,717)	—	—
Other income, net	(79)	(1,426)	(257)
Total other expenses, net	5,946	3,308	13,394
Income before income taxes	4,744	36,314	7,785
Income tax expense (benefit)	2,223	(69,283)	(174)
Income before equity in earnings of Medusa Spar LLC	2,521	105,597	7,959
Equity in earnings of Medusa Spar LLC	226	799	427
Net income available to common shares	$2,747	$106,396	$8,386
Net income per common share:			
Basic	$0.07	$2.81	$0.29
Diluted	$0.07	$2.76	$0.28
Shares used in computing net income per common share:			
Basic	39,522	37,908	28,817
Diluted	40,337	38,582	29,476

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

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CALLON PETROLEUM COMPANY
CONSOLIDATE STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	For the year ended December 31,		
	2012	2011	2010
Net income	$2,747	$106,396	$8,386
Other comprehensive income (loss):			
Change in fair value of derivatives designated as accounting hedges	(1,624)	2,561	(1,082)
Total other comprehensive income	$1,123	$108,957	$7,304

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)
(In thousands)

	Preferred Stock	Common Stock	Capital in Excess of Par	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
Balance at December 31, 2009	$—	$287	$243,898	$ 145	$(325,184)	$(80,854)
Deconsolidation of subsidiary	—	—	—	—	85,095	85,095
Comprehensive income:						
Net income	—	—	—	—	8,386	
Other comprehensive loss	—	—	—	(1,082)	—	
Total comprehensive income						7,304
Shares issued pursuant to employee benefit plans	—	1	192	—	—	193
Restricted stock	—	2	4,070	—	—	4,072
Balance at December 31, 2010	$—	$290	$248,160	$ (937)	$(231,703)	$15,810
Comprehensive income:						
Net income	—	—	—	—	106,396	
Other comprehensive income	—	—	—	2,561	—	
Total comprehensive income						108,957
Shares issued pursuant to employee benefit plans	—	—	207	—	—	207
Restricted stock	—	3	2,446	—	—	2,449
Common stock issued	—	101	73,661	—	—	73,762
Reconsolidate subsidiary	—	—	—	—	17	17
Balance at December 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 December 31, 2012	$—	$398	$328,116	$ —	$(122,543)	$205,971

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the year ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$2,747	$106,396	$8,386
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	51,043	49,753	32,629
Accretion expense	2,253	2,338	2,446
Amortization of non-cash debt related items	402	461	397
Amortization of deferred credit	(3,086)	(3,155)	(3,670)
Equity in earnings of Medusa Spar LLC	(226)	(799)	(427)
Deferred income tax expense	2,223	10,928	1,503
Valuation allowance	—	(80,211)	(1,503)
Unrealized gain on derivative contracts	(1,683)	—	—
Impairment of other property and equipment	1,176	—	—
Gain on acquired assets	—	(4,995)	—
Non-cash gain for early debt extinguishment	(1,366)	(1,942)	339
Non-cash expense related to equity share-based awards	1,697	1,337	2,347
Change in the fair value of liability share-based awards	1,620	761	760
Payments to settle asset retirement obligations	(1,314)	(2,563)	(2,486)
Changes in current assets and liabilities:			
Accounts receivable	(883)	(3,734)	59,527
Other current assets	100	180	(209)
Current liabilities	1,753	4,695	907
Payments to settle vested liability share-based awards	(3,383)	—	—
Change in natural gas balancing receivable	51	252	347
Change in natural gas balancing payable	(102)	(115)	(300)
Change in other long-term liabilities	205	100	(115)
Change in other assets, net	(1,937)	(520)	(776)
Cash provided by operating activities	51,290	79,167	100,102
Cash flows from investing activities:			
Capital expenditures	(133,299)	(100,243)	(59,908)
Acquisitions	(2,075)	—	(995)
Proceeds from sale of mineral interests and equipment	39,936	7,615	—
Investment in restricted assets related to plugging and abandonment	—	(150)	(375)
Distribution from Medusa Spar LLC	1,735	1,267	1,540
Cash used in investing activities	(93,703)	(91,511)	(59,738)
Cash flows from financing activities:			
Borrowings on senior secured revolving credit facility	53,000	—	—
Payments on senior secured revolving credit facility	(43,000)	—	(10,000)
Redemption of remaining 9.75% senior notes	—	—	(16,212)
Redemption of 13% senior notes	(10,225)	(35,062)	—
Issuance of common stock	—	73,765	—
Taxes paid related to exercise of employee stock options	(18)	—	(40)
Cash (used in) provided by financing activities	(243)	38,703	(26,252)
Net change in cash and cash equivalents	(42,656)	26,359	14,112

Cash and cash equivalents:			
Balance, beginning of period	43,795	17,436	3,635
Less: Cash held by subsidiary deconsolidated at January 1, 2010	—	—	(311)
Balance, end of period	$1,139	$43,795	$17,436

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

NOTE 1 – Description of Business and Basis of Presentation

Callon Petroleum Company is an independent crude oil and natural gas company, which since 1950 has been focused on building reserves and production both onshore and offshore through efficient operations and low finding and development costs. Today, the Company's principal development operations are in the Permian basin in West Texas. The Company's producing assets in the Gulf of Mexico provide significant cash flow to execute Callon's current onshore development operations. Following the December 2012 sale of our deepwater Gulf of Mexico property, discussed later within Note 12, the Company has one remaining deepwater Gulf of Mexico property, along with several Gulf of Mexico shelf properties, providing cash flow to support Callon's onshore development operations.

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.

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. Certain prior year amounts have been reclassified to conform to presentation in the current year. To the extent these amounts are material, we have either footnoted them within the Company's disclosures or have noted the items within this footnote.

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

Callon Petroleum Company | Notes to the Consolidated Financial Statements (All amounts in thousands, except share, per-share and per-hedge data) | Table of Contents

Correction of an Immaterial Error

During the second quarter of 2012, the Company determined that its December 31, 2011 financial statements reflected a misstatement caused by an error in adjusting the Company's deferred tax position at December 31, 2011. Management concluded that the impact of this error was immaterial on the prior reporting period. However, because the adjustment to correct the error in 2012 would have had a material impact on the 2012 financial statements, we corrected the prior period financial statements in the second quarter 2012 Form 10-Q and within the December 31, 2012 Form 10-K in accordance with SEC guidance. The adjustment had no effect on the Company's cash flow, and the information included in this Form 10-K sets forth the effects of this correction on the previously reported Balance Sheet and Income Statement as of and for the year ended December 31, 2011 as follows:

	Year ended December 31, 2011		
	As Reported	Adjustment	As Adjusted
Balance Sheet:			
Deferred tax asset	$63,496	$2,247	$65,743
Total assets	367,460	2,247	369,707
Retained deficit	(127,537)	2,247	(125,290)
Total stockholders' equity	198,955	2,247	201,202
Total liabilities and stockholders' equity	367,460	2,247	369,707
Income Statement:			
Income tax benefit	$(67,036)	$(2,247)	$(69,283)
Net income available to common shares	104,149	2,247	106,396
Net income per common share - Basic	2.75	0.06	2.81
Net income per common share - Diluted	2.70	0.06	2.76

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 (“US 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 crude oil and natural gas production receivables. The balance in the reserve for doubtful accounts netted within accounts receivable was $34 and $36 at December 31, 2012 and 2011, respectively. During 2012, 2011, and 2010 the Company recorded $0, $(281) and $281, respectively of bad debt expense in general and administrative expenses. The negative bad debt expense in 2011 relates to the collection of an amount charged to bad debt expense during 2010.

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 natural gas liquids is included in natural gas sales. Natural gas balancing receivables were $93 and $144 as of 2012 and 2011, respectively. Natural gas balancing payables were $653 and $756 as of 2012 and 2011, respectively.

Callon Petroleum Company | Notes to the Consolidated Financial Statements (All amounts in thousands, except share, per-share and per-hedge data) | Table of Contents

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 a significant percentage (>10%) of its total crude oil and natural gas production during each of the years ended:

	December 31,		
	2012	2011	2010
Shell Trading Company	39 %	45 %	44 %
Plains Marketing, L.P.	15 %	17 %	20 %
Enterprise Crude Oil, LLC	32 %	16 %	— %
Louis Dreyfus Energy Services	2 %	4 %	13 %
Other	12 %	18 %	23 %
Total	100 %	100 %	100 %

Because alternative purchasers of crude 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 crude oil and natural gas production.

F. Crude 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 property and equipment. 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 $13,331, $11,857 and $11,829 of these internal costs during 2012, 2011 and 2010, respectively.

When applicable, proceeds from the sale or disposition of crude 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.

Costs of crude oil and natural gas properties, including future development costs, which have proved reserves and properties which have been determined to be worthless, 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 management determines that these costs have been impaired.

Under the SEC's full cost accounting rules, we review the carrying value of our crude oil and natural gas properties each quarter. Under these rules, we compare the present value, discounted at 10%, of estimated future net cash flows from proved crude oil and natural gas reserves to the capitalized costs of crude oil and natural gas properties (net of accumulated depreciation, depletion and amortization and related deferred income taxes) which may not exceed a "ceiling".

These rules generally require that we price our future crude oil and natural gas production at the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Our reference prices are the West Texas Intermediate, or WTI, for crude oil and the Henry Hub spot price for natural gas. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. The reserve estimates exclude the effect of any derivatives we have in place. The rules require an impairment if our capitalized costs exceed this "ceiling". See Notes 12 and 14 for additional information regarding the Company's crude oil and natural gas properties.

Upon the acquisition or discovery of crude oil and natural gas properties, the Company estimates by using available geological, engineering and regulatory data the future net costs to dismantle, abandon and restore the property. Such cost estimates are periodically updated for changes in conditions and requirements. In accordance with asset retirement obligation guidance issued by the FASB, such costs are capitalized to the full-cost pool when the related liabilities are incurred. In accordance with SEC's 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 $6,424 and $3,998 at December 31, 2012 and 2011, respectively, using the straight-line method over estimated useful lives of three to 20 years. Depreciation expense of $760, $645 and $446 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, 2012, 2011 and 2010, respectively. The accumulated depreciation on other property and equipment was $13,238 and $12,688 as of December 31, 2012 and 2011, respectively. Included within the Company's other property and equipment, and excluded from depreciation, are certain assets held for sale, which were valued at $3,634 and $6,514 as of December 31, 2012 and 2011, respectively. The Company reviews its other property and equipment for impairment when indicators of impairment exist. See Note 7 for additional information regarding the assets held for sale and their fair values.

H. 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 13 for additional information.

I. 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 portions of contract designated as cash flow hedges are recognized as derivative expense (income). The last of the Company's derivative contracts designated as cash flow hedges expired on December 31, 2012. Derivative contracts executed during 2012 and outstanding as of December 31, 2012 are not designated as accounting hedges, and are also 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.

J. Income Taxes

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

K. Share-Based Compensation

The Company grants to directors and employees stock options, restricted stock awards ("RS awards"), and 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 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, recognized over the vesting period (generally three years) and classified as Accounts payable and accrued liabilities for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified as Other long-term liabilities.

L. Statements of Cash Flows

During the three year period ended 2012, the Company paid no federal income taxes. During the years ended December 31, 2012, 2011 and 2010, the company made cash interest payments of $13,920, $14,922 and $18,579, respectively.

M. Off-Balance Sheet Investment in Medusa Spar LLC

The Company holds a 10% ownership interest in Medusa Spar LLC ("LLC"), which is accounted for under the equity method of accounting for investments. The LLC owns a 75% undivided ownership interest in the deepwater spar production facilities at the Company's Medusa field in the Gulf of Mexico. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is 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 Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy Oil Corporation.

N. Consolidation of Variable Interest Entities

In June 2009, the FASB issued an accounting standard which became effective for the Company on January 1, 2010, and which amended US GAAP as follows:

- to require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a Variable Interest Entity ("VIE"), identifying the primary beneficiary of a VIE;
- to require ongoing reassessment of whether an enterprise is the primary beneficiary of a VIE, rather than only when specific events occur;
- to eliminate the quantitative approach previously required for determining the primary beneficiary of a VIE;
- to amend certain guidance for determining whether an entity is a VIE;
- to add an additional reconsideration event when changes in facts and circumstances pertinent to a VIE occur;
- to eliminate the exception for troubled debt restructuring regarding VIE reconsideration; and
- to require advanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a VIE.

The Company adopted the pronouncement for consolidation of variable interest entities on January 1, 2010. Upon adoption, and as discussed in Note 3, the Company reevaluated its interest in its subsidiary, Callon Entrada. Based on the evaluation performed, management concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which the Company is not the primary beneficiary. Therefore, effective January 1, 2010, Callon Entrada was deconsolidated from the consolidated financial statements of the Company. During the second quarter of 2011 and through the formal execution of a wind-down agreement with its former joint interest partner in the Entrada deepwater project, the Company became the primary beneficiary of Callon Entrada. Consequently, effective April 29, 2011, Callon Entrada was reconsolidated in the Company's financial statements. For additional information, see Note 3.

O. 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 reflects the potential dilution, using the treasury-stock method, which assumes that options were exercised and restricted stock was fully vested. Diluted EPS also includes the impact of unvested share appreciation plans. For awards in which the share price goals have already been achieved, shares are included in diluted EPS using the treasury-stock method. For those awards in which the share price goals have not been achieved, the number of contingently issuable shares included in the diluted EPS is based on the number of shares, if any, using the treasury-stock method, that would be issuable if the market price of the Company's stock at the end of the reporting period exceeded the share price goals under the terms of the plan.

P. Treasury Stock

The Company applies the weighted-average-cost method of accounting for treasury stock transactions and held 29 treasury shares as of December 31, 2012.

Q. Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

NOTE 3 - Global Settlement with Joint Interest Partner

During May 2011, the Company entered into a final project wind-down agreement (the "Agreement") with CIECO. As a result of this Agreement, which included both the assignment of the rights to the Entrada assets (including the rights to 50% of the assets previously held by CIECO and the rights to 50% of the assets held by Callon Entrada) and the proceeds from the ultimate sale of such assets, the Company gained the power to direct the activities related to the sale of the remaining assets, and therefore became the primary beneficiary of Callon Entrada. Therefore, Callon Entrada was consolidated in the Company's consolidated financial statements, effective April 29, 2011. Upon consolidating Callon Entrada, the Company estimated the fair values of the assets acquired to be $11,349 and liabilities assumed, primarily deferred tax liabilities associated with the tax basis difference in the assets, of Callon Entrada to be $2,681as a result of this Agreement. Also in connection with this Agreement, Callon Entrada agreed to pay to CIECO approximately $438, which represented the net balance of joint interest billings due to CIECO and which had been previously accrued. The agreement also included joint releases of each party from any further liabilities or obligations to the other party in connection with the Entrada project. The adjusted fair market value of the net assets acquired of approximately $8,759 were recorded during 2011 as a $5,041 gain and $3,718 as an adjustment to the Company's full cost pool of crude oil and natural gas properties.

While the Company continues to actively market these assets, its inability to complete a transaction over the past several quarters constituted an impairment indicator, which prompted the Company to reevaluate the remaining value of the assets. As of December 31, 2012, the remaining unsold assets, which are included in the Company's balance sheet as a component of Other property and equipment, net had carrying values of $3,634. During the year ended December 31, 2012, the Company sold assets valued at $527, and recorded an impairment charge of $1,177 to its Statement of Operations as a result of the Company's December 31, 2012 impairment analysis. The Company continues to actively market these assets, and will continue to monitor the assets for additional impairment. See Note 7 for additional information regarding the determination of the assets' fair values.

NOTE 4 - Earnings per Share

Basic net income per common share was computed by dividing net income by the weighted average number of shares of common stock outstanding during the year. Diluted net income per common share was determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options and restricted stock considered common stock equivalents computed using the treasury stock method.

A reconciliation of the basic and diluted net income per share computation is as follows (in thousands, except per share amounts):

	For the year ended December 31,		
	2012	2011	2010
(a) Net income	$2,747	$106,396	$8,386
(b) Weighted average shares outstanding	39,522	37,908	28,817
Dilutive impact of stock options	8	18	108
Dilutive impact of restricted stock	807	656	551
(c) Weighted average shares outstanding			

for diluted net income per share	40,337	38,582	29,476
Basic net income per share (a/b)	$0.07	$2.81	$0.29
Diluted net income per share (a/c)	$0.07	$2.76	$0.28

The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:

Stock options	52	67	122
Restricted stock	123	816	5

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NOTE 5 - Borrowings

	For the year ended December 31,	
	2012	2011
Principal components:		
Credit Facility	$10,000	$—
13% Senior Notes due 2016, principal	96,961	106,961
Total principal outstanding	$106,961	$106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	13,707	18,384
Total carrying value of borrowings	$120,668	$125,345

Senior Secured Revolving Credit Facility (the “Credit Facility”)

On June 20, 2012, Regions Bank increased the Company's Credit Facility to $200,000 with an associated borrowing base under the Credit Facility of $60,000 and a maturity of July 31, 2014. In October 2012, the Credit Facility was further amended to increase the borrowing base to $80,000, extend the maturity to March 15, 2016 and add Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Regions Bank continues to serve as Administrative Agent for the Credit Facility.

Following the sale of our interest in the deepwater Habanero field and as of December 31, 2012, the borrowing base was revised to $65,000, representing a 44% increase over the $45,000 borrowing base at December 31, 2011. The $39,410 proceeds from this sale, net of customary purchase price adjustments, were used to reduce outstanding borrowings on the Credit Facility to the $10,000 reflected on the Company's Consolidated Balance Sheet as of December 31, 2012.

Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The next redetermination is scheduled for the first quarter of 2013, and will be based upon year-end 2012 proved reserves. The Credit Facility is secured by mortgages covering the Company's major producing fields.

As of December 31, 2012, the balance outstanding on the Credit Facility was $10,000 with an interest rate on the Credit Facility of 2.72%, calculated as the London Interbank Offered Rate ("LIBOR"), plus a tiered rate ranging from 2.5% to 3.0%, which is based on the amount drawn on the Credit Facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. As of March 13, 2013, the balance outstanding on the Credit Facility was $25,000 as the Company drew an additional $15,000 in support of the Company's ongoing capital development program.

13% Senior Notes due 2016 (“Senior Notes”) and Deferred Credit

As of December 31, 2012, the Company had principal outstanding of $96,961 related to its 13% Senior Notes due 2016. The interest coupon is payable on the last day of each quarter.

Upon issuing the Senior Notes during November 2009, the Company reduced the carrying amount of the Old Notes by the fair value of the common and preferred stock issued in the amount of $11,527. The $31,507 difference between the adjusted carrying amount of the Old Notes and the face value of the Senior Notes was recorded as a deferred credit, which is being amortized as a reduction in interest expense over the life of the Senior Notes at an 8.5% effective interest rate.

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The following table summarizes the Company’s deferred credit balance at December 31, 2012:

Gross Carrying Amount	Accumulated Amortization	Carrying Value	Amortization Recorded during Current Year (a)	Estimated Annual Amortization Expense Expected to be Recognized in 2013 (b)
$31,507	$17,800	$13,707	$4,677	$3,300

(a) Of the amount recorded as amortization during the current year, $3,086 was recorded as a reduction of interest expense and $1,591 (discussed below) was recorded as a component of the gain on early extinguishment of debt.

(b) Deferred credit amortization expected to be recorded as a reduction in interest expense during, 2014, 2015 and 2016 is $3,592, $3,910, and $2,905, respectively.

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 (inclusive of $225 of redemption expenses) for Notes with a carrying value of $11,591 (inclusive of the $1,591 of accelerated deferred credit amortization).

Following the completion of an equity offering during February 2011, the Company redeemed $31,000 of the Notes. This redemption was completed in March 2011, and resulted in a gain on the early extinguishment of debt of $1,974. The gain represents the difference between the $35,062 paid for $37,004 (including $31,000 principal amount of the notes plus $6,004 of accelerated deferred credit amortization) carrying value of the Notes, offset by the $4,030 charge related to the 13% call premium required by the terms of the call option and $32 of redemption expenses.

Certain of the Company’s subsidiaries guarantee the Company’s obligations under the Senior Notes. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantors are minor.

Restrictive Covenants

The Indenture governing our Senior Notes and the Company’s Credit Facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon’s Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2012.

NOTE 6 – Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its crude oil and natural gas production. The Company utilizes primarily collars and swap derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for trading purposes.

Counterparty Risk

The use of derivative transactions exposes the Company to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. To reduce the Company's risk in this area, counterparties to the Company's commodity derivative instruments predominantly include a large, well-known financial institution and/or a large, well-known oil and gas company. The Company monitors counterparty creditworthiness on an ongoing basis; however, 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.

The Company executes commodity derivative transactions 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 transfer or terminate the arrangement.

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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 New York Mercantile Exchange ("NYMEX") price. The fair value of the Company's derivative instruments, depending on the type of instruments, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. See Note 7 for additional information regarding fair value.

During 2012, the Company elected not to designate its derivative contracts, nor does it expect to designate future derivative contracts, as an accounting hedge under FASB ASC 815. Consequently, any derivative contract not designated as an accounting hedge will be carried at its fair value on the balance sheet and marked-to-market at the end of each period, with the change in value reflected as a gain or loss on the statement of operations.

Prior to 2012, the Company's derivative contracts recorded on the Consolidated Balance Sheets were designated as cash flow hedges, and were recorded at fair market value with the changes in fair value recorded net of tax through OCI in stockholders' equity. The future cash settlements on effective derivative contracts were recorded as an increase or decrease in crude oil and natural gas sales. Both changes in fair value and cash settlements on effective derivative contracts were recognized as derivative expense (income).

The following table reflects the fair values of the Company's derivative instruments for the periods indicated:

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	12/31/12	12/31/11	12/31/12	12/31/11	12/31/12	12/31/11
Derivatives not designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$—	$—	$(125)	$—	$(125)	$—
Natural gas	Non-current	Other long-term liabilities	—	—	(116)	—	(116)	—
Crude oil	Current	Fair market value of derivatives	1,674	—	—	—	1,674	—
Crude oil	Non-current	Other long-term assets	250	—	—	—	250	—
	Subtotals		$1,924	$—	$(241)	$—	$1,683	$—
Derivatives designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$—	$—	$—	$—	$—	$—
Natural gas	Non-current	Other long-term assets	—	—	—	—	—	—
Crude oil	Current	Fair market value of derivatives	—	—	—	2,499	—	2,499
Crude oil	Non-current	Other long-term liabilities	—	—	—	—	—	—

Subtotals	$—	$—	$—	$2,499	$—	$2,499
Totals	$1,924	$—	$(241)	$2,499	$1,683	$2,499

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Derivatives not designated as hedging instruments under ASC 815

For the periods indicated, the Company recorded the following related to its derivative instruments that were not designated as accounting hedges and are recorded in the Statement of Operations as the gain or loss on derivative contracts:

	For the year ended December 31,		
	2012	2011	2010
Natural gas derivatives			
Realized gain, net	$34	$—	$—
Unrealized loss, net	(241)	—	—
Subtotal loss, net	$(207)	$—	$—
Crude oil derivatives			
Realized gain, net	$—	$—	$—
Unrealized gain, net	1,924	—	—
Subtotal gain, net	$1,924	$—	$—
Total gain on derivative instruments, net	$1,717	$—	$—

Derivatives designated as hedging instruments under ASC 815

The tables below present the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase (decrease) to crude oil and natural gas sales:

	For the year ended December 31,		
	2012	2011	2010
Amount of gain (loss) reclassified from OCI into income (effective portion)	$1,420	$(375)	$632
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	—	—	—

Derivative positions

Listed in the table below are the outstanding oil and natural gas derivative contracts as of December 31, 2012:

Product	Instrument	Average Volumes per Month	Quantity Type	Average Floor Price per Hedge	Average Ceiling Price per Hedge	Period
Crude oil (a) (b)	Collar	40	Bbls	$90.00	$116.00	Jan13 - Dec13

Product	Instrument	Average Volumes per Month	Quantity Type	Put/Call Price	Fixed-Price Swap	Period
Natural gas (c)	Swap	91	MMbtu	n/a	$3.52	Jan13 - Dec13
Natural gas (c)	Put Option	91	MMbtu	$3.00	n/a	Jan13 - Dec13
Natural gas (c)	Call Option	38	MMbtu	$4.75	n/a	Jan14 - Dec14

(a)

See "Subsequent Event" discussion below regarding the replacement of this crude oil derivative contract in January 2013.

(b) A collar is a combination of a sold call option (ceiling) and a purchased put option (floor).

(c) The natural gas swap, put and call option were executed contemporaneously. The "above market" $3.52/MMbtu swap price the Company received was offset by the value of the two options sold by the Company. The short natural gas put option, when combined with the swap, creates the potential for a reduction in the effective swap price if NYMEX natural gas prices are below $3.00/MMbtu in 2013. The short natural gas call option, when combined with the Company's long production position, represents a "covered call," and creates a $4.75/MMbtu ceiling during the covered period.

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Subsequent Event:

Derivative contracts executed subsequent to December 31, 2012 include the following:

Product	Instrument	Average Volumes per Month	Quantity Type	Put Price	Fixed-Price Swap	Period
Crude oil (a)	Swap	40	Bbls	n/a	$101.30	Feb13 - Dec13
Crude oil	Swap	30	Bbls	n/a	$93.35	Jan14 - Dec14
Crude oil (a)	Put	30	Bbls	$70.00	n/a	Jan14 - Dec14

(a) During January 2013, the Company monetized the remaining portion (Feb13-Dec13) of its 2013 crude oil collar positions of 40 Bbls per month reflected in previous table. The proceeds from this transaction, combined with the proceeds from the sale of the listed put for 30 Bbls per month, were used to finance the uplift in the crude oil swap for the period Feb13-Dec13.

NOTE 7 – Fair Value Measurements

Fair value is defined within the accounting rules as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The rules established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 Valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority.

Level 2 Valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability.

Level 3 Valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

Fair Value of Financial Instruments

Cash, Cash Equivalents, and Short-Term 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 on its Consolidated Balance Sheet. The fair value of Callon’s fixed-rate debt, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

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

	For the year ended December 31,			
	2012		2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$10,000	$10,000	$—	$—
13% Senior Notes due 2016 (a)	110,668	100,112	125,345	110,571
Total	$120,668	$110,112	$125,345	$110,571

(a) 2012 and 2011 Fair value is calculated only in relation to the $96,961 and $106,961 face value outstanding of the 13% Senior Notes, respectively. The remaining $13,707 and $18,384, respectively represents the Company's deferred credits and have been 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 (unless otherwise noted below) in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

(All amounts in thousands, except share, per-share and per-hedge data)

Commodity Derivative Instruments. Callon's derivative policy allows for commodity derivative instruments to consist of collars, natural gas and crude oil basis swaps, and similar commodity instrument structures. The fair value of these derivatives is derived using a valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract, and the values are corroborated by quotes obtained from counterparties to the agreements. 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 for each hierarchy level:

December 31, 2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current Portion	Fair market value of derivatives	$—	$1,674	$—	$1,674
Derivative financial instruments - non-current	Other assets, net	—	250	—	250
Sub-total assets		$—	$1,924	$—	$1,924
Liabilities					
Derivative financial instruments - current portion	Fair market value of derivatives	$—	$125	$—	$125
Derivative financial instruments - non-current	Other long-term liabilities	—	116	—	116
Sub-total liabilities		$—	$241	$—	$241
Total		$—	$1,683	$—	$1,683

December 31, 2011	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current Portion	Fair market value of derivatives	$—	$2,499	$—	$2,499
Derivative financial instruments - non-current	Other assets, net	—	—	—	—
Total		$—	$2,499	$—	$2,499

The derivative fair values above are based on analysis of each contract. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. See Note 6 for a discussion of net amounts recorded in the Consolidated Balance Sheet at December 31, 2012.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Asset Retirement Obligations Incurred in Current Period. Callon estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as (1) the existence of a legal obligation for an ARO, (2) amounts and timing of settlements, (3) the credit-adjusted risk-free rate to be used and (4) inflation rates. AROs incurred for the year ended December 31, 2012 and resulting in fair value measurement, including upward revisions to ARO liabilities of $81, were Level 3 fair value measurements. See Note 13 for a summary of changes in the Company’s ARO liability.

Other Property and Equipment. See Note 3 for additional information regarding the global settlement with Callon’s former joint interest partner on the project. During the second quarter of 2011, Callon acquired 100% of the rights to all remaining assets related to one of the Company's deepwater projects, which primarily consisted of surplus equipment.

As Callon is required to measure the assets acquired at fair value, Callon estimated each asset’s fair value based on several factors including (1) historical prices received for assets sold, (2) the similarity of unsold assets to those previously sold and the sales prices for those similar assets, (3) the number of market participants expected to have an interest in the assets, (4) the degree to which the asset has been customized and would require modification by a purchaser for use, and (5) the nature of the asset being held for sale (i.e. whether the asset is highly specialized, built-for-purpose, etc.). We also obtained certain information that was considered in the valuation of this equipment from an independent firm that is in the business of manufacturing and selling this equipment.

Values assigned to equipment sold prior to the June 30, 2011 reporting date and for which the exit price, as defined by US GAAP, became readily determinable, represented Level 2 fair value measurements equal to $3,954 of the total $11,349 acquired through the agreement. The remaining $7,395 of acquired assets represented Level 3 fair value measurements based on the limited ability of market pricing information for either identical or similar items. Certain assets were assigned no value in instances where the fair value was indeterminable due to the built-for-purpose or highly specialized nature of the assets. Also as a result of this settlement agreement, the Company assumed $2,681 of liabilities, which consisted entirely of a deferred tax liability associated with the basis difference of the equipment.

At December 31, 2012, the Company evaluated for impairment the unsold surplus equipment, noting the passage of time without significant sales activity, as an indicator of impairment. The Company followed the process described above to reevaluate the assets fair values. As a result of this analysis, the Company recorded an impairment charge of $1,177 , which was recorded as a loss on the Statement of Operations. The carrying value of the remaining unsold equipment is $3,634, at December 31, 2012, is recorded on the Consolidated Balance Sheet within Other Property and Equipment, net and represents a Level 3 fair value measurement. See Note 3 for additional 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:

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 $918, $811 and $690 in the years 2012, 2011 and 2010, 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 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 shares into the plan, increasing the quantity authorized and reserved for issuance under the Plan to 3,141 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, 2012, the 2011 Plan had 1,669 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 be immediate 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.

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Stock Incentive Award for Inducement of Employment

In April 2012 and as an inducement of employment, the Company awarded 100 restricted stock units to its Senior Vice President of Finance. The restricted stock units vest in one-third increments on each award anniversary date beginning July 1, 2013, and are being expensed ratably over the vesting period.

Following the Chief Operating Officer's ("COO") September 2010 departure from the Company, the COO forfeited his previously awarded 200 restricted and performance-based shares and 333 of his unvested performance-based stock options. Prior to his departure in 2010, the Company achieved the first of three performance metrics specified in the performance-based stock options agreement resulting in the COO vesting in 167 options, for which the Company recorded approximately $180 of compensation expense.

In April 2010 and as an inducement of employment, the Company awarded 50 restricted stock units to its Senior Vice President of Operations. The restricted stock units cliff vested on January 1, 2011, and were fully expensed as of December 31, 2010.

Cash-Settleable RSU Awards

Certain of the Company's RSUs awarded require cash-settlement. Cash-settleable RSU awards are accounted for as liabilities as the Company is contractually obligated to settle these awards in cash, and are recorded in the Company's consolidated balance sheet for the ratable portion of their fair values. Changes in the fair value of cash-settleable awards are recorded as adjustments to compensation expense. See Note 7 for additional information regarding fair value of cash-settleable awards.

A portion of the Company's cash-settleable RSU awards include a market-based vesting condition and may ultimately vest at a quantity different than the base RSUs awarded. The number of RSUs that cliff-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. As of December 31, 2012, the Company had the following cash-settleable RSU awards outstanding:

	Base Units Outstanding at December 31, 2012	Potential Minimum Units at Vesting at December 31, 2012	Potential Maximum Units at Vesting at December 31, 2012
Vesting in 2013	348	79	483
Vesting in 2014	569	62	1,077
Vesting in 2015	72	72	72
Other	—	—	—
Total cash-settleable RSU awards	989	213	1,632

For the year ended December 31, 2012, 364 cash-settleable RSUs subject to the peer market-based vesting described above vested at their maximum potential unit vesting of 546 units, resulting in a cash payment of $2,626. Additionally, 144 cash-settleable RSUs vested during 2012, resulting in a cash payment of $757. 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, 2012, 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 1,669.

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

	For the year ended December 31,					
	2012		2011		2010	
Share-based compensation expense for:	Equity-based	Liability-based	Equity-based	Liability-based	Equity-based	Liability-based
Options	$—	$ —	$24	$ —	$206	$ —
RSU equity awards	4,210	—	2,832	—	3,898	—
Cash-settleable RSU awards	—	2,916	—	1,335	—	1,396
401(k) contributions in shares	218	—	202	—	201	—
Total share-based compensation expense (a)	$4,428	$ 2,916	$3,058	$ 1,335	$4,305	$ 1,396

(a) The portion of this share-based compensation expense that was included in general and administrative expense totaled $4,081, $2,502 and $3,107 for the same years respectively, and the portion capitalized to oil and gas properties was $3,263, $1,891 and $2,594, respectively.

The following table presents the specified share-based compensation expense for the indicated periods:

	As of December 31,		
Unrecognized compensation costs related to:	2012	2011	2010
Unvested options	$—	$—	$57
Unvested RSU equity awards	6,320	5,748	3,353
Unvested cash-settleable RSU awards	2,826	2,498	2,676

Future expected share-based compensation expense for:	2013	2014	2015	Thereafter	Total
RSU equity awards	3,565	2,182	573	—	6,320
Cash-settleable RSU awards	1,862	937	27	—	2,826

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

Consolidated Balance Sheets Classification	2012	2011	2010
Accounts payable and accrued liabilities - current portion	$1,429	$604	$—
Other long-term liabilities - non-current portion	1,017	2,309	1,578
Total cash-settleable RSU awards	$2,446	$2,913	$1,578

Stock Options

The Company uses the Black-Scholes option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods. However, the Company issued no stock options for the past three years and no options vested during 2012. As of December 31, 2012, the Company had 67 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. During 2012, 31 options were exercised at a weighted average exercise price per option of $3.72 and with an aggregate intrinsic value of $56. Also During 2012, 60 options expired unexercised and 15 options were forfeited. As of December 31, 2011, the Company had 173 options outstanding and exercisable at a weighted average exercise price per option of $8.66, with no aggregate intrinsic value and with a weighted-average remaining contract life per unit of 2.0 years. The Company net-share settles option exercises and therefore receives no cash proceeds from the exercise of stock options.

Restricted Stock Units

The following table represents unvested restricted stock activity for the year ended December 31, 2012:

	Number of Shares	Weighted average Grant-Date Fair Value per Share	Period over which expense is expected to be recognized
Outstanding at the beginning of the period	1,918	$5.16	
Granted	1,008	5.22	
Vested (a)	(530)	3.29	
Forfeited	(101)		