CALLON PETROLEUM CO
Form 10-K
March 15, 2012
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K
for the year ended
December 31, 2011

[X]	Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2011, 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 $260.1 million as of June 30, 2011.

As of March 14, 2012, 39,410,094 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, 2011) relating to the Annual Meeting of Stockholders to be held on May 10, 2012, 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, 2011 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, a measure of heating value. One Mcf of natural gas generally contains one MMBtu of energy.
- BSEE: Bureau of Safety and Environmental Enforcement.
- 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.
- 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, 2011 by our production during 2011 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 located in the Permian Basin in Texas and the Haynesville Shale area in Louisiana. As of December 31, 2011, we had estimated net proved reserves of 10.1 MMbbls and 35.1 Bcf, or 15.9 MMboe. Of these reserves and on an MMboe basis, approximately 61% were located onshore in the Permian Basin and Haynesville Shale plays, compared with approximately 50% located onshore at December 31, 2010.

Well count information is presented gross unless otherwise indicated.

Our Business Strategy

Our goal is to increase stockholder value by:

- increasing reserves and production levels by using cash flows from, or monetization of, our Gulf of Mexico properties to acquire and develop lower risk, long-life onshore oil and natural gas properties;

- increasing our reserve life and predictability of production by focusing on acquisition and development of long-life onshore properties;

- diversifying risk by substantially increasing the number of productive wells we own; and

- strengthening our balance sheet by focusing on maintaining liquidity and a reduction of our average debt per Boe of proved reserves.

Our Strengths

We believe that we are well positioned to achieve our business objectives and to execute our strategy because of the following competitive strengths:

- Our offshore properties generate substantial cash flow, which we can deploy in the acquisition, exploration and development of onshore properties. Since 2009, we have invested nearly $150 million onshore primarily using offshore cash flows.

- We are replacing Gulf of Mexico Shelf high decline-rate, natural gas production with longer reserve life, liquids-rich production from our onshore drilling programs.

- We have positioned ourselves for further growth by:

  Acquiring 14,470 additional net Permian Basin exploration acres in early 2012, which represents a 152% increase over our Permian acreage position at year-end 2011.

  Initiating a horizontal oil drilling program on a portion of our Permian acreage scheduled to begin drilling during the second quarter of 2012.

- We have increased reserve life 79% to 8.6 years at year-end 2011 from 4.8 years at year-end 2008.

- Our management team is experienced in oil and natural gas acquisitions, exploration, development and production in the areas in which we focus our operations.

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- On December 31, 2011, our total liquidity position was approximately $88.8 million, including $43.8 million of available cash and $45.0 million of unused borrowing base available under our senior secured credit facility. The borrowing base has increased by 50% over the base at December 31, 2010.

Recent Developments

Subsequent to December 31, 2011, we completed two acreage acquisitions in the northern Midland Basin in Borden County. The northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin (where our other Permian Basin properties are located), which increases the risk associated with drilling activities on the acquired acreage. Together, these acquisitions included a total of approximately 16,020 gross (14,470, net) acres, and significantly increased our acreage position in the Permian Basin by 152% to a total of 24,010 acres compared to 9,540 acres held year-end 2011. For additional information regarding these acquisitions, please refer to the Onshore Properties portion of this Item 1.

Exploration and Development Activities

During 2011, capital expenditures on an accrual basis for exploration and development costs related to oil and natural gas properties included these expenditures (in millions):

36 wells drilled on the Permian Basin acreage of which 23 wells were producing at year-end	$ 85.3
Leasehold acquisitions and seismic	2.9
Costs incurred on offshore properties	1.8
Plugging and abandonment costs in the Gulf of Mexico	2.6
Capitalized interest	0.7
Capitalized general and administrative costs allocated directly to exploration and development projects	11.9
Total capital expenditures	$ 105.2

With our continued operational focus onshore, primarily in the Permian Basin, we expect that substantially all of our 2012 capital expenditures will be focused on the acquisition, development and operation of onshore properties in the United States, with 10% of capital expenditures directed towards our offshore properties including an up-dip recompletion of the Habanero #2 well. Our projected 2012 capital expenditures budget is discussed in Management's Discussion and Analysis and Results of Operations, which is included in Part II, Item 7 of this filing.

Acquisitions and Divestitures

In addition to the previously discussed 16,020 gross (14,470, net) northern Permian Basin acres we acquired in February 2012, during the second quarter of 2011, we acquired for $2.2 million approximately 1,215 gross (480, net), unevaluated acres in the Pecan Acres field, located in Midland County and in proximity to our Carpe Diem field. Pecan Acres provides 26 gross (10, net) drilling locations, and we are currently operating a rig drilling vertical wells at Pecan Acres. We have drilled and stimulated two Pecan Acres wells, which are currently flowing back after stimulation. Also at Pecan Acres, we have drilled a third well and are currently drilling a fourth, with plans to fracture stimulate these wells in March 2012. During 2012, we plan to drill an additional six wells at Pecan Acres.

Also during 2011, we sold for $2.8 million our Mystic Bayou field, located in south Louisiana. In addition to the proceeds, the acquirer assumed approximately $0.9 million of ARO related to the properties.

Oil and Natural Gas Properties

As of December 31, 2011, our estimated net proved reserves totaled 15.9 MMBoe and included 10.1 MMBbls and 35.1 Bcf, with a pre-tax present value, discounted at 10%, of $309.9 million. Pre-tax present value is a non-US GAAP financial measure, which we reconcile to the US GAAP standardized measure of $270.4 million in note (d) to the table below. Oil constitutes approximately 63% of our total estimated equivalent net proved reserves and approximately 44% 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, 2011:

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	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	5,631	11,783	7,595	$48,932
Haynesville Shale	Callon	—	12,382	2,064	3,114
Total Onshore		5,631	24,165	9,659	$52,046
Gulf of Mexico Deepwater:					
Mississippi Canyon 538/582 “Medusa”	Murphy	3,810	2,719	4,263	$213,421
Garden Banks Block 341 “Habanero”	Shell	610	4,574	1,373	46,606
Total Gulf of Mexico Deepwater		4,420	7,293	5,636	$260,027
Gulf of Mexico Shelf and Other:					
West Cameron Block 295	Apache	7	1,253	216	$3,563
East Cameron Block 2	Apache	10	639	116	2,398
East Cameron Block 257	Dynamic Offshore	—	754	126	946
Other (c)	Various	7	1,014	175	(9,090)
Total Gulf of Mexico Shelf and Other		24	3,660	633	$(2,183)
Total Net Proved Reserves		10,075	35,118	15,928	$309,890

(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 an 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 an market price equivalence basis, a barrel of oil or NBLs 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, 2011, 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, 2011, in accordance with accounting for asset retirement obligations rules. The negative Pre-Tax 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, 2011 was $270.4 million inclusive of the $39.5 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $5.60 used in the 2011 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 $98.98 used in the 2011 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 61% of year-end 2011 proved reserves on a Boe basis as compared to 50% of 2010 reserves on a Boe basis, demonstrating our strategy of using our offshore cash flow to explore and develop our onshore properties.

Permian Basin

Our primary target in the southern Midland Basin area of the Permian Basin has been the Wolfberry play, which is located on our properties in Crockett, Ector, Midland, and Upton counties, Texas, and which we believe to be a proven, low-risk oil play that includes the Sprayberry, Dean, and Wolfcamp formations. Certain of our southern Midland Basin properties also include the Atoka and Strawn formations. As of December 31, 2011, we owned approximately 9,540 net acres in the Permian Basin. Following two recent acquisitions of acreage on which we will target different formations and as discussed below, the Company increased its ownership within the Basin to approximately 24,010 net acres.

As of December 31, 2011, approximately 48% of the Company's proved reserves were attributable to properties in the Permian Basin. Also as of December 31, 2011, our Permian Basin properties were producing 1,335 Boe/d from 65 wells, of which 31 were placed onto production (and one well taken offline) during 2011. This 2011 exit-rate production represents a 143% increase over the 2010 exit rate of 550 Boe/d producing from 35 wells. Average net production from the Company's Permian Basin properties increased 135% to 965 Boe/d in 2011 from 411 Boe/d in 2010.

Subsequent to December 31, 2011, we significantly expanded our Permian Basin acreage position by acquiring approximately 16,020 gross (14,470, net) exploratory acres in the northern portion of the Midland Basin in Borden County. The northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin, and therefore has increased risk associated with drilling activities on the acquired acreage. The acquisition costs were funded from existing cash balances. The Company has an average 90% working interest across the contiguous acreage positions and is the operator.

For additional information regarding our Permian Basin properties, including our 2012 capital expenditures program and future development plans for the region, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Haynesville Shale

Callon holds a 69% working interest in a 624 gross (430, net) acre portion of the Haynesville Shale natural gas unit located in southern Bossier Parish, Louisiana. Initial production from the George R. Mills Well No. 1H, our only well on the property, commenced on September 3, 2010. As of December 31, 2011, the well has produced 2.1 Bcf, and we have an additional six gross (four, net) drilling locations on the acreage. Approximately 13% of our year-end 2011 proved reserves were attributable to our Haynesville Shale property. The Company's one producing Haynesville Shale natural gas well was shut-in for 35 days during the fourth quarter of 2011 due to well interference from an offsetting well. Production was restored in mid-March 2012 following a successful workover.

For additional information regarding the Company's Haynesville Shale property, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Gulf of Mexico Deepwater Properties

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater 1999 discovery, in which we own a 15% working interest, is located in 2,235 feet of water approximately 50 miles offshore Louisiana. 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 55 MMBoe.

During 2011, the Medusa field produced 641 MBoe net to Callon from eight wells which accounted for 35% of our total production. Six of the field's wells continue to produce from their initial completions as of December 31, 2011. We project that 1.7 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 developing another 1.2 MMBoe of net PUDs by drilling an additional well in late 2013. As of December 31, 2011, the current projected economic life of the field is expected to run through 2025.

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In December 2003, we transferred our undivided 15% working interest in the spar production facilities to Medusa Spar LLC ("LLC") in exchange for cash proceeds of approximately $25 million and a 10% ownership interest in the LLC. A discussion of this transaction is included in Part II, Item 7 of this filing under Off-Balance Sheet Arrangements.

Habanero, Garden Banks Block 341

The Habanero field, in which we own an 11.25% working interest, is located in 2,015 feet of water approximately 115 miles offshore Louisiana. Production from the Habanero 52 oil sand commenced in late November 2003. The field is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest owned by Murphy. Since the field entered production in 2003, cumulative gross volumes have approximated 29 MMBoe.

During 2011, Habanero produced 197 MBoe net to Callon from two wells accounting for 11% of our total production. Our plans include in the fourth quarter of 2012 the development of PUDs by a sidetrack of the Habanero #2 well. As of December 31, 2011, the Company expects to reach the economic life of the field in 2019.

For additional information regarding the Company's Deepwater properties, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Gulf of Mexico Shelf and Other Properties

We own interests in 18 producing wells in 11 oil and natural gas fields in the shelf area of the Gulf of Mexico. These wells produced 551 MBoe net to our interest in 2011, which accounted for 30% of our total production. For additional information regarding the Company's Shelf and other properties, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Proved Reserves

In December 2008 the Securities and Exchange Commission (“SEC”) approved amendments to its oil and gas reserves estimation and disclosure requirements. The amendments, among other things:

- allow the use of reliable technologies to estimate proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes;
- require disclosure of oil and gas proved reserves by significant geographic area;
- permit the optional disclosure of probable and possible reserves;
- modify the prices used to estimate reserves for SEC disclosure purposes to a 12-month average beginning-of-the-month price instead of a period-end price; and
- require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party.

The new requirements were effective for the Company’s year-end financial statements and Annual Report on Form 10-K for the year ended December 31, 2009, and as such the reserves and related information for 2009, 2010 and 2011 are presented consistent with the requirements of the new rule. The new rule does not require prior-year reserve information to be restated, and as such all information related to periods prior to 2009 is presented consistent with the prior SEC rules for the estimation of 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.

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	Years Ended December 31,		
	2011	2010	2009
Proved developed:			
Oil (MBbls)	5,069	4,503	4,346
Natural Gas (MMcf)	11,605	12,715	12,301
MBoe	7,003	6,622	6,396
Proved undeveloped:			
Oil (MBbls)	5,006	3,645	2,133
Natural Gas (MMcf)	23,513	20,241	6,802
MBoe	8,925	7,019	3,266
Total proved:			
Oil (MBbls)	10,075	8,149	6,479
Natural Gas (MMcf)	35,118	32,957	19,103
MBoe	15,928	13,641	9,663
Estimated pre-tax future net cash flows [a]	$568,798	$379,448	$216,702
Pre-tax discounted present value [a] [b]	$309,890	$205,532	$137,368
Standardized measure of discounted future net cash flows[a] [b]	$270,357	$198,916	$135,921

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2011, 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 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, 2011 was $270.4 million inclusive of the $39.5 million discounted estimated future income taxes relating to such future net revenues. The natural gas Mcf prices of $5.60 used in the 2011 reserve estimates have been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected oil prices of $98.98 used in the 2011 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 15 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.

Proved Undeveloped Reserves

Annually, the Company reviews its PUDs to ensure an appropriate plan exists 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 are (i) allocation of capital to projects in our 2012 capital budget and (ii) in subsequent years, on the basis of capital allocation in our business plan, each of which generally is governed by our expectations of internally generated cash flow. 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:

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	PUDs (MBoe) at December 31,		
	2011	2010	2009
Permian Basin	4,861	2,928	932
Haynesville Shale	1,730	1,757	—
Total Onshore PUDs	6,591	4,685	932
Medusa	1,186	1,186	1,186
Habanero	1,148	1,148	1,148
Total Deepwater PUDs	2,334	2,334	2,334
Total Shelf and other PUDs	—	—	—
Total PUDs	8,925	7,019	3,266

Our 2,334 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 activities 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 both Medusa and Habanero to drill or sidetrack PUDs within a shorter period of time than originally estimated. The Company currently forecasts that one of the two producing wells in the Habanero field will deplete in 2012, and the field operator has provided notice that the well will be sidetracked to a location with PUD reserves of 1,148 Mboe in the fourth quarter of 2012. Within the Medusa field and to access the PUD reserves of 1,186 MBoe, the Company expects to drill a new well in 2013. During 2011, the Company did not convert any offshore PUDs to PDPs.

The Company's plans to develop its onshore, Permian Basin PUDs include a multi-year drilling program, which is expected to be completed on existing acreage within five years. Similarly, the Company plans to resume drilling on its Haynesville field, and expects to convert its existing PUDs within the next four years.

The Company's PUDs increased 27% to 8,925 MBoe from 7,019 MBoe at December 31, 2011 and 2010, respectively. Additions during the year added 2,988 MBoe to the Company's PUDs, offset by 1,082 MBoe primarily comprised of transfers to PDPs as a result of our development program. None of these additions to our PUD reserves were offset by amounts no longer deemed to be economic PUDs at year-end. Revisions to PUDs were not material in 2011. Of our year-end 2010 PUD reserves, 13% were converted to proved developed producing reserves by year end 2011, at a total cost of $28.5 million, net.

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 asset evaluation and management.

Callon’s controls over reserve estimates included retaining Huddleston & Co., Inc., 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 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.

The Board of Directors meets with management, including the Senior Vice President of Operations, to discuss matters and policies including those related to reserves. During our last fiscal year, we have not filed any reports with other federal agencies which contain an estimate of total proved net oil and natural gas reserves.

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, the Company's sale of oil and natural gas for the periods indicated.

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	Years Ended December 31,		
	2011	2010	2009
	(in thousands, except per unit data)		
Production			
Natural gas and NGLs (Mcf)	5,081	4,892	5,740
Oil (MBbl)	996	859	1,012
Total (MBoe)	1,843	1,674	1,969
Revenues			
Natural gas and NGL sales	$26,682	$24,639	27,417
Oil sales	100,962	65,243	73,842
Total revenues	$127,644	$89,882	$101,259
Lease Operating Expenses			
Production costs	$17,929	$16,094	$16,778
Severance/production taxes	1,826	816	528
Gathering	592	802	1,141
Total lease operating expenses	$20,347	$17,712	$18,447
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on derivatives) (a)	$5.25	$5.04	$4.78
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) (a)	5.25	4.91	4.45
Oil ($/Bbl, including realized gains (losses) on derivatives) (b)	101.34	75.97	73.00
Oil ($/Bbl, excluding realized gains (losses) on derivatives) (b)	101.72	75.97	55.84
Operating costs per Boe - Total Consolidated			
Production costs	$9.73	$9.61	$8.52
Severance/production taxes	0.99	0.49	0.27
Gathering	0.32	0.48	0.58
DD&A	26.42	19.00	16.99
Interest	6.36	7.95	9.70
Total operating costs per Boe	$43.82	$37.53	$36.06

(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) 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.

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, 2011, the Company was in the process of drilling two development wells (which are excluded from the table below) and had nine development oil wells (which are included in the table below) awaiting fracture stimulation including seven first-time well stimulations.

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	Years ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	36	32.77	20	19.37	—	—
Natural Gas	—	—	1	0.69	—	—
Non-productive	—	—	—	—	—	—
Total	36	32.77	21	20.06	—	—
Exploration: (a)						
Oil	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total	—	—	—	—	—	—

(a) Our wells have been drilled within the productive boundaries of statistical plays, and are therefore classified as development well.

The following table sets forth productive wells as of December 31, 2011:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	75	60.70	12	5.52
Royalty interest	3	0.10	5	0.13
Total	78	60.80	17	5.65

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

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

	Year ended December 31,								
	2011			2010			2009		
	Production Volumes (MBoe)	% of Total Proved Reserves		Production Volumes (MBoe)	% of Total Proved Reserves		Production Volumes (MBoe)	% of Total Proved Reserves	
Offshore - Gulf of Mexico:									
Medusa	641	27	%	593	33	%	751	51	%
Habanero	197	8	%	233	10	%	370	16	%
Shelf and other	551	4	%	616	7	%	829	17	%
Total offshore:	1,389	39	%	1,442	50	%	1,950	84	%
Onshore:									
Permian Basin	353	48	%	150	33	%	19	16	%
Haynesville natural gas shale	101	13	%	82	17	%	—	—	%
Total onshore:	454	61	%	232	50	%	19	16	%
Total	1,843	100	%	1,674	100	%	1,969	100	%

Leasehold Acreage

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

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2011.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	2,519	965	901	699	3,420	1,664
Texas (a)	7,148	6,318	4,256	3,221	11,404	9,539
Federal onshore (b)	—	—	64,963	64,963	64,963	64,963
Federal waters (c)	50,680	17,784	40,944	11,360	91,624	29,144
Total	60,347	25,067	111,064	80,243	171,411	105,310

(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. Excluded from the above table and as previously noted in the Onshore Properties discussion, Callon acquired in February 2012 approximately 16,020 gross (approximately 14,470 net) acres in the northern portion of the Midland Basin. This acreage is also subject to certain drilling requirements with which the Company's development plans are expected to comply.

(b) The Company's lease of this acreage, located in Nevada, has approximately seven years remaining, and had a carrying value at December 31, 2011 of approximately $2.3 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) We have two federal blocks in offshore waters, comprising 11,520 gross (2,304 net) acres that will expire in the fourth quarter of 2012. In additional, we hold other insignificant federal waters acreage that will expire during 2012. Because we have no development plans for the acreage, the acreage had no carrying value at December 31, 2011.

Title to Properties

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

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insurance for all offshore wells, though unless contractually bound to do so, the Company does not carry control of well insurance for onshore operations.

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 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 $100 million in excess liability coverage, which is in addition to and triggered if the policy limits for other coverages are 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,					
	2011		2010		2009	
Shell Trading Company	45	%	44	%	45	%
Plains Marketing, L.P.	17	%	20	%	23	%
Enterprise Crude Oil, LLC	16	%	—	%	—	%
Louis Dreyfus Energy Services	4	%	13	%	15	%
Other	18	%	23	%	17	%
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, and own or lease field offices in the area of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

Employees

Callon had 88 employees as of December 31, 2011, which included 10 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

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employees.

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 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 Notices to Lessees and other guidance documents as well as an Interim Final Rule augmenting the existing regulations with more stringent safety, engineering and environmental requirements. The DOI Bureaus have also recently 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 a Notice 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

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regulation of oil and natural gas exploration and production on the OCS. The tightening of regulation on the OCS could impose 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 statues, 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 dispose of produced saltwater 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 for contamination of 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 authorized. 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 July 28, 2011, the EPA proposed a rule to subject oil and natural gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs under the Clean Air Act, and to impose new and amended requirements under both programs. Under the proposal, EPA would, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and natural gas operations, imposing requirements on those operations. EPA is also proposing NSPS standards for completions of hydraulically fracturing natural gas wells. The proposed standards include the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology (MACT) standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. EPA is under a court order to finalize the rules, with the current deadline of April 3, 2012. Should these rules become final and applicable to our operations, they could result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

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, seems unlikely, the EPA has been moving forward with rulemaking to regulate GHGs as pollutants under the CAA. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

On June 3, 2010, EPA published its so-called "GHG tailoring rule" that will phase in federal prevention of significant deterioration (PSD) permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. Those permitting provisions, when 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, with the first annual report due in 2012 for the year 2011. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, keep records of, and report GHG emissions associated with our operations.

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 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 states 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. Interim results of the study are expected in 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 and public comment. 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 similar production operations.

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 2011.

The hydraulic fracturing activity is limited to the oil and natural gas bearing Clearfork, Sprayberry, Wolfcamp, Cline and Atoka 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 county.

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 1.4 million gallons of fresh water, approximately 1.2 million pounds of sand and other elements including enzymes and Guar, a common food additive.

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. 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 will be submitted to the Railroad Commission of Texas with the completion report for the well. Additionally, a list of all other chemical ingredients not required by the registry will also be provided to the Railroad Commission for disclosure on a publicly accessible website.
There have not been any incidents, citations or suits related to the Company's hydraulic fracturing activities involving environmental concerns.

Surface Damage Statues ("SDAs"). In addition, eleven states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most SDAs also contain bonding requirements and specific expenses for exploration and operating activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

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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 of a country that denies “similar or like privileges” to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and natural gas lease. If this restriction is violated, the corporation's lease 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.

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, BOEM, BSEE 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.

Available Information

We make available free of charge on our Internet web site (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC. You may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like Callon, that file electronically with the SEC.

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

Item 1A. Risk Factors
Risk Factors

Depressed oil and natural gas prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which are extremely volatile, and the oil and natural gas markets are cyclical. 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 senior secured 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.

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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 37% of our estimated net proved reserves are natural gas, and 46% of our production in 2011 was natural gas. A sustained reduction in natural gas prices could have an adverse effect on our results of operation 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 15 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.

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, 2011 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, 2011, approximately 29% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 56% of total proved reserves by volume, and approximately 26% of our PUDs were attributable to our deepwater properties. 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

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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 45% of our production during 2011 and 35% of our estimated proved reserves at December 31, 2011. Similarly, our Gulf of Mexico shelf properties accounted for approximately 30% of our production during 2011 and 4% of our estimated proved reserves at December 31, 2011. 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. There is currently a shortage of pressure pumping equipment and crews, primarily within our Permian Basin area of operation. 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 part of the value of our production and reserves is concentrated in a small number of offshore properties, and any production problems or inaccuracies in reserve estimates related to those properties would adversely impact our business. During 2011, approximately 63% of our daily production came from four of our properties in the Gulf of Mexico. Moreover, one property accounted for 35% of our production during this period. In addition, at December 31, 2011, approximately 35% of our total net proved reserves were located in two fields in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production or if the actual reserves associated with any one of these producing properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

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 early 2012, we purchased 14,470 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

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- 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.

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

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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 all of our properties, and have limited influence over the operations of some of these properties, particularly our two deepwater properties. 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.

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,

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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. Interim results of the study are expected in 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 drilling in new or emerging formations, such as the Haynesville Shale and Permian Basin Wolfcamp formation, 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 use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. We also plan to begin horizontal drilling in our Permian Basin properties in 2012. Our experience with horizontal drilling in the Haynesville Shale, as well as the industry's drilling and production history, while growing, is limited. 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 attractive as we anticipate and 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 and 2007 from Hurricanes Katrina and Rita 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

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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. The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodities Futures Trading Commission (the "CFTC") is required to implement rules relating to these activities by July 16, 2012. On October 18, 2011, the CFTC approved regulations to set position limits for certain futures and option contracts in the major energy markets, which regulations are presently being challenged in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association. The Dodd-Frank Act may also require us to comply with margin requirements and with certain clearing and trade execution requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The schedule for promulgation of final rules has changed repeatedly, but the current schedule published by the Commodities Futures Trading Commission contemplates finishing final regulations in 2012.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act 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 and 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,

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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.

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 will be required on an annual basis beginning in 2012 for emissions occurring in 2011. We will have to incur costs associated with this reporting obligation.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states have already taken legal measures to reduce or measure GHG emissions often involving the planned development of GHG emission inventories and/or regional 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

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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, with results of the study anticipated to be available by late 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 and public comment. A committee of the U.S. House of Representatives is also conducting 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 have adopted, and other states 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. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. 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 (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) 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.

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ITEM 3. Legal Proceedings

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

ITEM 4. Mine Safety Disclosures

Not applicable.
PART II.

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

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	
	2011		High	Low
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
	2010			
First quarter	ended	March 31 2010	$5.90	$1.40
Second quarter	ended	June 30 2010	8.80	4.46
Third quarter	ended	September 30 2010	6.72	3.54
Fourth quarter	ended	December 31 2010	6.39	4.45

As of March 1, 2012 the Company had approximately 3,322 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 2011, 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, 2011 (securities amounts are presented in thousands).

	Outstanding Options		
Plan Category	Number of securities to be	Weighted-average exercise price of	Number of securities

	issued upon exercise of outstanding options	outstanding options	remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	99	$ 10.34	2,349
Equity compensation plans not approved by security holders	74	6.44	—
Total	173	8.66	2,349

For additional information regarding the Company's benefit plans and share-based compensation expense, see Notes 9 and 10 to the Consolidated Financial Statements.

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Performance Graph

The following graph compares the yearly percentage change for the five years ended December 31, 2011, in the cumulative total shareholder return on the Company’s common stock against the cumulative total return for the following:

- the Morningstar Group Index consisting of independent oil and gas drilling and exploration companies; and
- the New York Stock Exchange Market Index.

Company/Market/Peer Group	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
Callon Petroleum Company	$100.00	$109.45	$17.30	$9.98	$39.39	$33.07
NYSE Composite Index	$100.00	$109.14	$66.42	$85.40	$97.02	$93.46
Morningstar Group Index	$100.00	$140.25	$55.41	$99.97	$104.51	$90.66

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, 2011 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, 2009 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.

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	For the year ended December 31,				
	2011	2010	2009 Restated	2008	2007
Statement of Operations Data:	(In thousands, except per share amounts)				
Operating revenues:					
Oil and natural gas sales	$127,644	$89,882	$101,259	$141,312	$170,768
Medusa BOEM royalty recoupment	—	—	40,886	—	—
Total operating revenues	$127,644	$89,882	$142,145	$141,312	$170,768
Operating expenses:					
Non-impairment related operating expenses	$88,022	$68,703	$68,692	$97,497	$114,418
Impairment of oil and gas properties	—	—	—	485,498	—
Total operating expenses	$88,022	$68,703	$68,692	$582,995	$114,418
Income (loss) from continuing operations	39,622	21,179	73,453	(441,683)	56,350
Net income (loss) (a)	104,149	8,386	46,796	(438,893)	15,194
Earnings (loss) per share ("EPS"):					
Basic	$2.75	$0.29	$2.12	$(20.68)	$0.73
Diluted	$2.70	$0.28	$2.11	$(20.68)	$0.71
Weighted average number of shares outstanding for Basic EPS	37,908	28,817	22,072	21,222	20,776
Weighted average number of shares outstanding for Diluted EPS	38,582	29,476	22,200	21,222	21,290
Statement of Operations Data:					
Net cash provided by operating activities	$79,167	$100,102	$19,698	$89,054	$109,283
Net cash used in investing activities	(91,511)	(59,738)	(43,189)	(4,511)	(215,791)
Net cash provided by (used in) financing activities	38,703	(26,252)	10,000	(120,667)	(157,862)
Balance Sheet Data:					
Oil and natural gas properties, net	$215,912	$168,868	$130,608	$159,252	$681,706
Total assets	367,460	218,326	227,991	266,090	792,482
Long-term debt (b)	125,345	165,504	179,174	272,855	392,012
Stockholder' equity (deficit)	198,955	15,810	(80,854)	(129,804)	287,075
Proved Reserves Data:					
Total oil (MMBbls)	10,075	8,149	6,479	6,027	24,531
Total natural gas (MMcf)	35,118	32,957	19,103	18,652	116,454
Total proved reserves (MBoe)	15,928	13,641	9,663	9,136	43,940
Standardized measure	$270,357	$198,916	$135,921	$86,305	$1,133,989

(a) 2011 net income includes $67.0 million of income tax benefit related to the reversal of the Company's deferred tax asset valuation allowance. See Note 12 for additional information.

(b) 2011 and 2010 long-term debt includes a non-cash deferred credit of $18,384 and $27,543, 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 6 for additional information.

(c) 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. See Note 16 for additional information.

We follow the full-cost method of accounting for oil and gas properties. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not exceed the sum of (1) the estimated future net revenues from proved reserves using a 12-month pricing average discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax (the full-cost ceiling amount). If these capitalized costs exceed the full-cost ceiling amount, the excess is charged to expense. For the year ended December 31, 2008, the Company recorded a $485.5 million impairment of oil and gas properties

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as a result of the ceiling test. See Notes 2 and 13 to the Consolidated Financial Statements for a description of the relevant accounting policy and the Company's oil and gas properties disclosures, respectively.

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.

Well count information is presented gross unless otherwise indicated.

Overview and Outlook

During 2011, Callon had net income and fully diluted earnings per share of $104.1 million and $2.70, respectively, compared to net income of $8.4 million and fully diluted earnings per share of $0.28, respectively for 2010. Net income during 2011 includes an income tax benefit of $67.0 million, primarily related to the full reversal of the valuation allowance we previously recorded against our deferred tax assets (see Note 12 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.

Also during 2011, Callon replaced 224% of production volumes for the year and increased proved reserves by approximately 2.3 MMBoe, or 17%, net of current-year production. We further diversified our net proved reserves with nearly 61% on a MMBoe basis now being located onshore as of December 31, 2011 vs. 50% at December 31, 2010. Further, compared to the prior year, Callon increased Permian Basin oil production by 143%, from a combination of drilling 36 additional vertical wells, of which 23 were placed on production during 2011, and due to eight wells that were drilled during 2010 and placed onto production during 2011.

We made significant progress during 2011 towards our goal of strengthening our financial position and improving our liquidity, which better positions Callon for future growth. Significant financial achievements include:

- Reported an income tax benefit of $67.0 million primarily from the reversal of the valuation allowance previously recorded 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.

- Completed a public offering of 10.1 million shares during February 2011 for which the Company received $73.8 million in net proceeds. While approximately 47% of the proceeds were used to reduce the Company's debt outstanding, the remaining proceeds were available primarily for general corporate purposes and to fund the Company's acquisition and development activities in the Permian Basin.

- Redeemed $31 million aggregate principal amount of our Senior Notes during March 2011, resulting in a net gain on the early extinguishment of debt of approximately $2.0 million. This redemption reduced the principal of the Company's debt outstanding by approximately 22% to $107 million, reduced 2011 interest expense by approximately $3.2 million and will reduce each prospective full year interest expense by $4.0 million through the Senior Notes' maturity in 2016.

- Increased the borrowing base under our credit facility with Regions Bank to $45 million, representing a $15 million or 50% increase over the previously approved $30 million borrowing base and simultaneously received a reduction in the credit facility's minimum interest rate from 6% to 3%.

- Increased cash flows related to higher production from our Permian Basin properties. Our Permian production rate has increased approximately 143% since December 31, 2010 to a 2011 exit rate of approximately 1,335 net Boe/d compared to a 2010 exit rate of 550 Boe/d.

- Executed an agreement with our former joint interest partner to complete the wind-down of the Company's previously abandoned deepwater Entrada Project. Through the agreement, the Company acquired rights to the remaining, unsold assets from the project. Upon recording these assets in the Company's consolidated financial statements, we recognized a gain of $5.0 million and a related income tax benefit of $2.7 million.

Highlights of our onshore and deepwater development program include:

- Onshore – Permian Basin

Our primary target in the Permian Basin has been the Wolfberry play, which is located on our properties in Crockett, Ector, Midland, and Upton counties, Texas, and which we believe to be a proven, low-risk oil play that includes the Sprayberry, Dean, and Wolfcamp formations. Certain of our Permian Basin properties also include the Atoka and Strawn formations. As of December 31, 2011, we owned approximately 9,540 net acres in the Permian Basin. Following two recent acquisitions discussed below, the Company increased its ownership to approximately 24,010 net acres.

As of December 31, 2011, approximately 48% of Callon's proved reserves were attributable to our properties in the Permian Basin. Also as of December 31, 2011, our Permian Basin properties were producing 1,335 boe/d from 65 wells, of which 31 were placed on production (and one well taken offline) during 2011 and 35 were producing in prior years. This 2011 exit-rate production represents a 143% increase over the 2010 exit rate of 550 Boe/d producing from 35 wells. Average net production from our Permian Basin properties increased 135% to 965 Boe/d in 2011 from 411 Boe/d in 2010.

During 2011, we invested approximately $85.3 million into our Wolfberry development program, which included drilling 36 vertical wells targeting the Wolfberry trend, of which 23 were producing prior to December 31, 2011, seven are scheduled to be fracture stimulated in the first and second quarters of 2012 and six wells were in the process of being brought online. Throughout 2011, Callon fractured stimulated 40 vertical wells including 35 first-time well stimulations. We expect to continue to carry an inventory of wells awaiting fracture stimulation until the service organizations in the region build the additional capacity needed to handle the region's requirements.

With respect to our 2012 capital budget, 79% will be dedicated to further developing our Permian Basin properties, and includes plans to drill up to 28 development wells including seven horizontal and 21 vertical wells. During the second quarter of 2012, we plan to commence a horizontal drilling program expected to ultimately include up to 24 wells on our southern Permian Basin properties. This drilling program was based on our ongoing evaluation of our acreage position in the East Bloxom Field, located in Upton County, TX, and recent industry drilling results in northern Upton County and western Reagan County, TX. To support our horizontal drilling program, we recently contracted a new-generation drilling rig for a term of two years that is expected to be delivered in April 2012 at a cost of approximately $9.1 million per full year.

In February 2012, we significantly expanded our Permian Basin acreage position with the acquisition of approximately 16,020 gross (14,470 net) acres in the northern portion of the Midland basin in Borden County. We plan to initiate a 3-D seismic survey in the first half of 2012 and subsequently commence exploratory drilling in the third quarter of 2012. Our drilling plans include three horizontal exploration wells and one vertical exploration well.

- Onshore – Haynesville Natural Gas Shale

The Company currently holds a 69% working interest in approximately 430 net acres in the Haynesville Shale natural gas unit. Initial production from our first, and currently only, well on the property commenced in September 2010. As of December 31, 2011, the well has produced 2.1 billion cubic feet of natural gas. Approximately 13% of our year-end 2011 proved reserves were attributable to our Haynesville Shale property. Our multi-year development plan for this property includes drilling and operating a total of seven gross (five, net) horizontal wells. We have no remaining drilling obligations in our Haynesville Shale position, and currently plan to mobilize a rig to the area once natural gas prices warrant continued development of the remaining six planned horizontal wells.

The Company's one producing Haynesville Shale natural gas well was shut-in for 35 days during the fourth quarter of 2011 due to well interference from an offsetting well. Production was restored in mid-March 2012 following a successful workover.

• Offshore – Deepwater Properties

Our deepwater properties continue to play a key role in our transition to onshore operations by providing strong cash flows used to fund the development of our onshore properties. Together, our two deepwater properties produced approximately 840 MBoe equal to approximately 45% of the Company's total production in 2011, and at year-end had 5.6 MMBoe of net proved reserves. Production from our deepwater properties is approximately 84% oil, which in the present market offers favorable pricing in relation to natural gas. Oil prices for production from our two deepwater fields are adjusted based upon Mars WTI differential for Medusa production and Argus Bonito WTI differential for Habanero production.

Six of our Medusa field's eight wells continue to produce from their initial completions and, as of December 31, 2011, had an estimated 1.7 MMBoe of net PDNPs that will 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 developing another 1.2 MMBoe of net PUDs by drilling an additional well in late 2013. Continued development plans include drilling in 2014 an additional well targeting probable reserves.

On March 29, 2011, the operator of our Medusa property successfully recompleted the A6 well from the T4-C zone to the T4-B zone (at a net cost to Callon of $0.2 million), which increased production net to Callon from approximately 80 Boe/day to approximately 850 Boe/day. As of December 31, 2011, production from the A6 well was approximately 425 Boe/day, net. Callon has confirmed with the operator that the Medusa platform will be shut-in approximately 25 days during the second quarter of 2012 due to planned construction activities on the West Delta 143 oil pipeline, through which Medusa's production is transported.

Callon received confirmation from the operator of the Habanero Field that drilling of the #2 sidetrack well targeting up-dip PUDs will commence during the fourth quarter of 2012. In addition, Callon has been notified that the Habanero Field will be shut-in for scheduled maintenance operations on the Auger platform, which processes Habanero production volumes. As a result, the operator of the Habanero Field expects production to be offline for a total of approximately 60 days during the second and third quarters 2012.

• Offshore – Shelf & Other Properties

We own interests in 18 producing wells in 11 oil and natural gas fields in the shelf area of the Gulf of Mexico. These wells produced 551 MBoe net to our interest in 2011, which accounted for 30% of our total production. Production from the East Cameron Block 257 Field, which in the third quarter of 2011 contributed to our total production approximately 260 Boe/d, was suspended in the fourth quarter of 2011 due to a natural gas leak in a upstream section of the Stingray Pipeline which transports production volumes from the field. Production will re-commence once the Stingray Pipeline is brought back online, which is currently anticipated to occur before July 2012.

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 increased by $26.4 million during 2011 to $43.8 million compared to $17.4 million at December 31, 2010. The increase in our cash balance is primarily attributable to higher oil prices, increased production levels and the receipt of $73.8 million from the sale of 10.1 million shares of common stock. Offsetting these increases were approximately $35 million used to repurchase $31 million principal amount of our outstanding Senior Notes and the use of cash for ongoing operations, including capital expenditures.

In January 2010, we amended our senior secured credit agreement to include Regions Bank as the sole arranger and administrative agent. The senior secured credit agreement matures on September 25, 2012, and provides for a $100 million facility with a current borrowing base of $45 million. The current borrowing base represents a $15 million, or 50%, increase over the previous $30 million borrowing base as of December 31, 2010. Simultaneous with the May 2011 increase in the borrowing base, Regions Bank also approved a reduction in the minimum interest rate on the facility from 6% to 3%. The rate is calculated as LIBOR, with a minimum of 0.5%, plus a tiered rate ranging from 2.5% to 3.0%, which is based on the amount drawn on the facility. The senior secured credit agreement has a commitment fee of 0.5% per annum on the unused portion of the borrowing base that is payable quarterly. As of December 31, 2011, the interest rate on the facility was 3%, though no amounts were outstanding under the facility as of that date. We continue to discuss with Regions Bank the syndication of our senior secured credit agreement, and expect any such syndication to include an extension of the maturity beyond September 25, 2012.

At December 31, 2011, we had approximately $107 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly, a $31 million decrease from amounts outstanding at December 31, 2010 following the partial redemption previously discussed. The principal reduction in our Senior Notes reduced 2011 cash interest paid by approximately $3.2 million, and will reduce cash interest paid each full-year thereafter by approximately $4.0 million.

2012 Capital Expenditures

For 2012, we designed a flexible capital spending program, which we plan to fund from cash on hand and cash flows from operations. We believe these resources along with borrowings under our senior secured credit agreement, if needed, will be adequate to meet our capital, interest payments, and operating requirements for 2012. However, depending on commodity prices and other economic conditions we experience in 2012, our capital budget may be adjusted up or down.

While on a consolidated basis, inflation has not had a material impact on us, we have experienced increasing inflationary pressure in our Permian Basin operations, and we believe this trend may affect future development at our Medusa and Habanero fields. With respect to the Permian, increased demand for materials and services, including the costs associated with various down-hole drilling difficulties and other similar development costs, have exceeded our original development cost expectation. For example, drilling rig rates have increased 34% due to increased labor costs to maintain crew continuity, and the costs of fracture stimulation services and associated wireline services have increased approximately 13% during 2011 as compared to 2010. We also continue to monitor drilling rig operator efficiency, and have replaced one operator with another that we believe will improve drilling efficiency.

Our 2012 capital budget includes approximately $139 million, of which 79% is dedicated to our onshore activities. Our budget includes further exploration and development of our Permian Basin properties with plans to drill approximately 28 gross wells including seven horizontal wells and 21 vertical wells. As previously discussed, we expect to drill four of the planned horizontal wells as development wells on our East Bloxom property. The remaining three horizontal wells, which will be exploration wells, are planned for our newly acquired northern Midland Basin acreage. We expect to drill 20 vertical wells on our southern Permian Basin properties and one vertical exploration well on our newly acquired northern Midland Basin acreage. Components of the 2012 capital budget include:

Development of legacy, southern Permian Basin properties	$62
Acquisition and exploration of northern Permian Basin properties	48
Gulf of Mexico development, primarily Habanero	14
Capitalized general and administrative costs	13
Capitalized interest and other	2
Total projected capital expenditures budget	$139

Our total liquidity at December 31, 2011 was $88.8 million, including $43.8 million of cash available at December 31, 2011 and $45 million of borrowing base availability under our Credit Facility. Our total liquidity on March 1, 2012 and subsequent to the previously discussed northern Permian Basin acreage acquisition, was approximately $70.0 million, including $25.0 million of cash available and the $45 million of borrowing base availability under our Credit Facility.

The following table includes the Company's contractual obligations and purchase commitments as of December 31, 2011, at which date the Company had no product delivery commitments:

(amounts in thousands) Payments due by Period

	Total	< 1 Year	1 - 3 Years	3 - 5 Years	>5 Years
13% Senior Notes	$106,961	—	—	$106,961	—
Office space lease commitments	2,960	107	700	684	1,469
Medusa Oil Pipeline Throughput Commitment	62	22	27	13	—
Total	$109,983	$129	$727	$107,658	$1,469

During February 2012, we contracted a drilling rig for a term of two years to support our horizontal drilling program in the Permian Basin. This agreement increases our expected contractual obligations as follows: <1 year of $6.9 million and 1-3 years of $11.4 million. 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 $4.4 million and 1-3 years of $6.8 million.

Summary cash flow information is provided as follows:

Operating Activities. For the year ended December 31, 2011, net cash provided by operating activities was $79.2 million, compared to $100.1 million for the same period in 2010. Excluding from 2010 operating cash flows $52.7 million related to the BOEMRE royalty recoupment and related interest, cash flow provided by operating activities increased year-over-year by approximately 67% or $31.8 million primarily as a result of a 29% increase in the average realized sales price on an equivalent basis and a 10% increase in total production on an equivalent basis.

Investing Activities. For the year ended December 31, 2011, net cash used in investing activities was $91.5 million as compared to $59.7 million for the same period in 2010. The $31.8 million increase in net cash used in investing activities is primarily attributable to an increase in capital expenditures related to drilling activity on our Permian Basin acreage, which was partially offset by $7.6 million in proceeds received for the sale of certain mineral interests and assets acquired as part of the Entrada project wind-down agreement discussed below and in Note 3 to the financial statements.

Financing Activities . For the year ended December 31, 2011, net cash provided by financing activities was $38.7 million compared to cash used by financing activities of $26.3 million during the same period of 2010. The 2011 net cash provided by financing activities included $73.8 million of net proceeds from an equity offering offset by approximately $35.1 million used to redeem a $31.0 million principal portion of our outstanding 13% Senior Notes and to pay the $4.0 million call premium and other redemption expenses. The 2010 expenditures related to the $10.0 million repayment of outstanding borrowings under the Credit Facility and the $16.2 million redemption of the Company's remaining outstanding 9.75% Senior Notes.

Income Taxes

As of December 31, 2010, we continued to carry a full valuation allowance against our net deferred tax assets. We consider both the positive and negative information in determining whether it is more likely than not that our deferred tax assets are recoverable. With the loss we incurred in 2008, primarily as a result of a writedown of our oil and gas properties following the ceiling test, which created a loss on an aggregate basis for the three-year period ended December 31, 2008. Because of this cumulative loss together with our near term projected results of operations, we established a full valuation allowance as of December 31, 2008, and have continued to carry the full valuation allowance each reporting period since December 31, 2008.

We reported profitable operations from 2009 to 2011, and have 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 valuation allowance at December 31, 2011, which then had a balance of $67.0 million. For additional information, see Note 12 to the Consolidated Financial Statements.

Callon Entrada

Effective January 1, 2010, Callon Entrada Company ("Callon Entrada"), a variable interest entity, was deconsolidated from our consolidated financial statements because we no longer had the power to direct the activities that most significantly affected Callon Entrada's economic activities being the liquidation of the surplus equipment related to the Entrada project. The deconsolidation of Callon Entrada resulted in the removal of approximately $1.8 million of current assets, $2.0 million of current liabilities, $30.3 million of deferred tax assets, $30.3 million of tax valuation allowance and approximately $84.8 million of non-recourse debt and the related obligation for the cumulative amount of interest. Retained earnings increased by $85.1 million as a cumulative effect of change related to this accounting standard. No gain was recognized in the statement of operations.

During the second quarter of 2011, we entered into a final project wind-down agreement with CIECO Energy LLC ("CIECO"), our former joint interest partner in the Entrada deepwater project. The agreement provides for the extinguishment of all existing agreements and commitments between the parties as it relates to the past development of the Entrada project. The agreement includes a formal extinguishment of the non-recourse credit agreement between Callon Entrada and CIECO and the assignment to Callon Entrada of CIECO's 50% rights to the remaining assets including primarily the unsold, residual equipment and all engineering data related to the Entrada project, and resulted in our becoming Callon Entrada's primary beneficiary and consolidating its results with ours.

For additional information regarding Callon Entrada and related matters, 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,						
	2011	2010	Change	% Change	2009	Change	% Change
Net production:							
Oil (MBbls)	996	859	137	16 %	1,012	(153)	(15)%
Natural Gas (MMcf)	5,081	4,892	189	4 %	5,740	(848)	(15)%
Total production (MBoe)	1,843	1,674	169	10 %	1,969	(295)	(15)%
Average daily production (Boe)	5,049	4,587	462	10 %	5,395	(808)	(15)%
Average realized sales price (see below):							
Oil (Bbl)	$101.34	$75.97	$25.37	33 %	$73.00	$2.97	4 %
Natural Gas (Mcf)	5.25	5.04	0.21	4 %	4.78	0.26	5 %
Total (Boe)	69.26	53.69	15.57	29 %	51.44	2.25	4 %
Oil and natural gas revenues (in thousands):							
Oil revenue	$100,962	$65,243	$35,719	55 %	$73,842	$(8,599)	(12)%
Natural Gas revenue	26,682	24,639	2,043	8 %	27,417	(2,778)	(10)%
Total	$127,644	$89,882	$37,762	42 %	$101,259	$(11,377)	(11)%
Additional per Boe data:							
Sales price	$69.26	$53.69	$15.57	29 %	$51.44	$2.25	4 %
Lease operating expense	(11.04)	(10.58)	(0.46)	4 %	(9.37)	(1.21)	13 %
Operating margin	$58.22	$43.11	$15.11	35 %	$42.07	$1.04	2 %

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)	$95.14	$79.52	$15.62	20 %	$61.80	$17.72	29 %
Basis differential and quality adjustments (a)	7.58	(2.39)	9.97	417 %	(4.64)	2.25	(48)%
Transportation	(1.00)	(1.16)	0.16	(14)%	(1.32)	0.16	(12)%
Hedging	(0.38)	—	(0.38)	100 %	17.16	(17.16)	(100)%
Average realized oil price ($/Bbl)	$101.34	$75.97	$25.37	33 %	$73.00	$2.97	4 %
Average NYMEX natural gas price ($/Mcf)	$4.03	$4.40	$(0.37)	(8)%	$4.17	$0.23	6 %
Basis differential and quality adjustments (b)	1.22	0.51	0.71	139 %	0.28	0.23	82 %
Hedging	—	0.13	(0.13)	(100)%	0.33	(0.20)	(61)%
Average realized natural gas price ($/Mcf)	$5.25	$5.04	$0.21	4 %	$4.78	$0.26	5 %

(a)

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.

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

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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, 2008	$82,963	$58,349	$141,312
Volume increase (decrease)	6,165	(989)	5,176
Price decrease	(32,639)	(31,832)	(64,471)
Impact of hedges increase	17,353	1,889	19,242
Net decrease during the year	(9,121)	(30,932)	(40,053)
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

Total Revenue

Total oil and natural gas revenues of $127.6 million for the year ended December 31, 2011 increased approximately $37.8 million or 42% from $89.9 million during the year ended December 31, 2010. The year-over-year increase in total revenue was principally driven by higher realized pricing on an equivalent unit basis combined with an increase in overall production. Compared to full year of 2010, and on an equivalent basis, the average price realized by the Company increased 29%, while overall production on an equivalent basis increased by 10%. Production increases were primarily attributable to the Company's development program on its Permian Basin properties, to the addition of the Company's Haynesville Shale natural gas well which began producing late in the third quarter of 2010 and to a well recompletion at our offshore, deepwater Medusa field. Offsetting the increases in production were normal and expected declines in other properties, the third quarter 2011 temporary 17 day and 21 day shut-in of our Medusa and Habanero wells, respectively, due to a tropical storm and other required maintenance work on the facilities, and a 35-day shut-in of our Haynesville well due to interference caused by an offsetting well.

Total oil and natural gas revenues of $89.9 million for the year ended December 31, 2010 were approximately $11.4 million, or 11%, less than $101.3 million for the same period of 2009. The largest contributors to the year-over-year decline included a 15% decline in production on an equivalent basis, partially offset by a 4% increase in average realized prices. Compared to 2009, the decline in production on an equivalent basis during 2010 was primarily driven by normal and expected declines in our other properties and damage to one of our Gulf of Mexico natural gas field production facilities. These declines were partially offset by new production from our Permian Basin and Haynesville Shale properties.

Oil Revenue

For the year ended December 31, 2011, 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. As noted above, both an increase in commodity prices and production resulted in increased 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. 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. As discussed above, production increases relate primarily to progress in developing our Permian Basin properties and the 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.

Oil revenues of $65.2 million for the year ended December 31, 2010 were approximately $8.6 million, or 12%, less than oil revenues of $73.8 million for the same period of 2009. The largest contributor to the decline was a 15% decrease in production, partially offset by a 4% increase in the average realized oil price. In addition to normal and expected production declines, volumes declined primarily due to our working interest in Habanero #1 decreasing from 25% to 11.25% in June 2009 following the payout of a sidetrack on this well. The payout was associated with a third quarter 2007 sidetrack of the #1 well for which the operator elected to non-consent. These declines were partially offset by production from our newly drilled and completed wells on the Permian Basin properties that we acquired during the fourth quarter of 2009.

Natural Gas Revenue

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 the production from East Cameron #2 well, 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.

Natural gas revenues of $24.6 million for the year ended December 31, 2010 were approximately $2.8 million, or 10%, less when compared to natural gas revenues of $27.4 million for the same period of 2009. The largest contributor to the decline was a 15% decrease in production, partially offset by a 5% increase in the average realized sales price of natural gas. The largest contributor to the decline in production was the shut-in of the East Cameron #2 well, which was shut-in during January 2010 due to damage resulting from a fire on a third-party facility. Production at the East Cameron #2 well was restored during the latter part of the fourth quarter of 2010 following the completion of the necessary repairs and BOEM inspections. Also contributing to the production decrease was the Habanero #1 well reversionary interest discussed above in the oil revenue analysis, while the remaining decrease in production was due to normal and expected declines from our other properties and production suspensions related to well recompletions and BOEM recompletion work approval at our Mobile Block 864 well. Offsetting these declines are increases from our Permian Basin properties discussed above, and production from our first Haynesville natural gas well, which was placed on production during September 2010.

Operating Expenses

	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					

	For the year ended December 31,				Total Change		Boe Change	
	2010	Per Boe	2009	Per Boe	$	%	$	%
Lease operating expenses	$17,712	$10.58	$18,447	$9.37	(735)	(4)%	$1.21	13 %
Depreciation, depletion and amortization	31,805	19.00	33,443	16.98	(1,638)	(5)%	2.02	12 %
General and administrative	16,507	9.86	13,355	6.78	3,152	24 %	3.08	45 %
Accretion expense	2,446	1.46	3,149	1.60	(703)	(22)%	(0.14)	(9)%
Acquisition expense	233	0.14	298	0.15	(65)	(22)%	(0.01)	(7)%
Total operating expenses	$68,703		$68,692					

Lease Operating Expenses

For the year ended December 31, 2011, lease operating expenses ("LOE") per Boe of $11.04 increased by 4% or $0.46 compared to $10.58 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.

For the year ended December 31, 2010, LOE decreased 4% to $17.7 million compared to $18.4 million for the same period in 2009. The primary contributor to the reduction in LOE was normal and expected declines in production in addition to the reduction in our working interest in Habanero #1 well following the payout of a sidetrack on this well. Partially offsetting these decreases, LOE increased related to our acquisition of the Permian Basin properties and a modest increase in insurance rates due to adding additional coverage to our program designed to better protect the Company from damage caused by severe weather.

Depreciation, Depletion and Amortization

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. 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. Also contributing to the current rate increase are the ongoing onshore development cost increases in the area.

For the year ended December 31, 2010, DD&A decreased approximately $1.7 million or 5% to $31.8 million compared to $33.4 million for the same period of 2009. Production declines account for nearly all of the decrease, while a rate increase partially offset the production volume decreases.

General and Administrative, net of amounts capitalized

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

For the year ended December 31, 2010, G&A expenses, net of amounts capitalized, increased $3.2 million or 24% to $16.5 million from $13.4 million for the same period of 2009. Our performance-based incentive program runs from April to March, and adjustments to our accruals are recorded during the first quarter upon completion of the program and evaluation by our Compensation Committee. During the first quarter of 2009, we recorded a 75% reduction in incentive-based compensation related to our actual 2008 results. These results, which were negatively affected by the decline in oil and natural gas prices, the abandonment of the Entrada project and worsening broader economic conditions, were lower than the performance goals set for fiscal year 2008. Conversely, the increase experienced during 2010 relates primarily to a 21% increase in incentive-based compensation related to exceeding performance goals set for fiscal year 2009. Also contributing to the increase are (1) a valuation adjustment to mark to fair value a portion of our share-based awards that will vest in the future which are accounted for as a liability, (2) additional employee-related costs, including non-recurring early retirement expenses, (3) costs associated with adding new employees, including relocation and related costs, and (4) higher legal costs and other charges related to an arbitration hearing involving a dispute with our joint interest partner in the Entrada development project. Partially offsetting the increases are $2.2 million of expenses related to staff reductions incurred during the second quarter of 2009 for which no similar charge was recorded during 2010.

Accretion Expense

Accretion expense related to our asset retirement obligation decreased 4% for the year ended December 31, 2011 compared to the same periods of 2010. Accretion expense correlates directionally with the Company's asset retirement obligation (“ARO”). At December 31, 2011, our ARO of $13.9 million was lower than the $15.9 million ARO at December 31, 2010. See Note 14 for additional information regarding the Company's ARO.

For the year ended December 31, 2010, accretion expense decreased $0.7 million or 22% to $2.4 million from $3.1 million incurred during the same period of 2009. The Company’s accretion expense decreases as its ARO decreases. As of December 31, 2010, our average ARO liability for 2010 of $15.0 million was significantly lower than our average ARO liability of $27.0 million for the same period in 2009. For additional information regarding the company’s oil and natural gas properties and the related ARO, see Notes 13 and 14 included to the Consolidated Financial Statements.

Other (Income) Expense

	For the year ended December 31,						
	2011	2010	$ Change	% Change	2009	$ Change	% Change
Interest expense	$11,717	$13,312	$(1,595)	(12)%	$19,089	$(5,777)	(30)%
Callon Entrada non-recourse credit facility interest expense (See Note 3)	—	—	—	— %	7,072	(7,072)	(100)%
(Gain) Loss on early extinguishment of debt	(1,942)	339	(2,281)	(673)%	—	339	— %
Gain related to acquired assets, net (See Note 3)	(5,041)	—	(5,041)	100 %	—	—	— %
9.75% Senior Notes restructuring expenses	—	—	—	— %	1,024	(1,024)	(100)%
Interest on BOEM royalty recoupment	—	(91)	91	(100)%	(7,681)	7,590	(99)%
Other (income) expense	(1,426)	(166)	(1,260)	759 %	190	(356)	(187)%
Total other (income) expenses	$3,308	$13,394			$19,694		

Income tax (benefit) expense	$(67,036)	$(174)	$(66,862)	38,426 %	$7,623 *	$(7,797)	100 %
Equity in earnings of Medusa Spar LLC	799	427	372	87 %	660	(233)	(35)%

* 2009 Income tax expense has been restated. See Note 1.

Interest Expense

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

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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.

For the year ended December 31, 2010, interest expense decreased $5.8 million or 30% to $13.3 million compared to $19.1 million for the same period of 2009. The decrease was primarily due to the $3.7 million amortization of our deferred credit related to the Senior Notes, which is recorded as a decrease to interest expense. Also reducing interest expense during 2010 was a decrease in the amount of discount amortization recognized related to our 9.75% Senior Notes, 92% of which were exchanged during 2009. Further, the remaining $16.1 million of outstanding 9.75% Senior Notes that did not participate in the exchange were later redeemed on April 30, 2010 resulting in approximately $1.1 million of interest expense savings during 2010 as compared to 2009.

Callon Entrada Non-Recourse Credit Agreement Interest Expense

As discussed in Note 3 to the Consolidated Financial Statements and as a result of the deconsolidation of Callon Entrada effective January 1, 2010, we incurred no expense related to this non-recourse credit facility during 2011 or 2010.

(Gain) Loss on 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.

For the year ended December 31, 2010, the loss on early extinguishment of debt was $0.34 million, though no similar expense was incurred during 2009. The $0.34 million related to the 1% call premium, equal to $0.16 million, paid to redeem the remaining $16.1 million of 9.75% Senior Notes not exchanged during the restructuring of the 9.75% Senior Notes, plus $0.18 million for the accelerated amortization of the 9.75% Senior Notes’ remaining discount and debt issuance costs. For additional information, see Note 6 to the Consolidated Financial Statements.

Gain related to acquired assets, net

For information concerning the net gain on acquired assets including the related income tax benefit, please see Note 3 to the Consolidated Financial Statements.

9.75% Senior Notes Restructuring Expense

During the fourth quarter of 2009, we exchanged our 9.75% Senior Note for the 13% Senior Notes and convertible preferred stock. In connection with this exchange, we incurred $1.0 million of financing cost related to consultant and legal expenses. For additional information, see Note 6 to the Consolidated Financial Statements.

Interest on BOEM Royalty Recoupment

During 2009 we filed for a $44.8 million royalty recoupment for royalty payments previously made on production from Medusa field. During the first quarter of 2010, the Company received both the recoupment of principal and $7.7 million of interest. In addition, the Company is no longer required to make any future royalty payments to the BOEM related to its Medusa production. For additional information, see Note 16 to the Consolidated Financial Statements.

Income Tax Benefit

The income tax benefit of $67.0 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. As a result, we reversed the $67.0 million valuation allowance at December 31, 2011.

As explained in Note 1, the Company restated its 2009 income tax expense to reflect the tax expense incurred related to income generated by the settlement of its oil and natural gas hedges, which were valued at $21.8 million at December 31, 2008. Additionally, see Note 12 to our Consolidated Financial Statements for additional information related to our income taxes.

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:

- cost of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and natural gas properties;
- payroll costs including the related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and natural gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs do not include any costs related to the production of oil and natural gas or general corporate overhead;
- costs associated with unevaluated properties, those lacking proved reserves, are excluded from the depletable base. These unevaluated property costs are added to the depletable base at such time as wells are completed on the properties, 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) ; and
- 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.

- 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

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Under the full cost method of accounting, the Company compares, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and natural gas properties net of related deferred taxes. The Company refers to this comparison as a "ceiling test." If the net capitalized costs of proved oil and natural gas properties exceed the estimated discounted (at 10%) future net cash flows from proved reserves, the Company is required to write-down the value of its oil and natural gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are based on a twelve-month average pricing assumption and include consideration of existing cash flow hedges. Given the volatility of oil and natural gas prices, it is reasonably possible that the Company's estimates of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and natural gas properties could occur in the future. See Notes 2 and 13 for additional information regarding the Company's oil and natural gas properties.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows

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

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

Changes in these prices and/or costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and natural gas reserves for the Company's properties that have relatively short productive lives.

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

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

Unproved Properties

Costs, including capitalized interest, associated with properties that do not have proved reserves are excluded from the depletable base, and are included in the line item "Unevaluated properties 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 14 for additional information.

Derivatives

To manage oil and natural gas price risk on a portion of its planned future production, we have historically utilized hedges on approximately 50% of our projected production volumes in any given year. The Company does 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.

The Company's derivative contracts that existed at December 31, 2011 are accounted for as cash flow hedges, and are recorded at fair market value on its consolidated balance sheet under the caption "Fair Market Value of Derivatives". The estimated fair value of these contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options. Changes in fair value recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The cash settlements on these contracts are recorded in the Statement of Operations as an increase or decrease in oil and natural gas sales. The changes in fair value related to ineffective derivative contracts are recognized as derivative expense (income). The cash settlement on these contracts is also recorded within derivative expense (income).

In February 2012, we elected to no longer designate subsequent derivative contracts as accounting hedges under FASB ASC 815-20-25. As such, all future derivative positions, including a collar into which we entered during February 2012, will be carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized and unrealized gains or losses are recorded on the statement of operations. Unrealized gains (losses) related to our derivative contracts not designated as accounting hedges will be reported as a component of the Company's revenues.

For additional information regarding derivatives and their fair values, see Notes 7 and 8 to the Consolidated Financial Statements and Part II, Item 7A Commodity Price Risk.

Income Taxes

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

Subsequent Events

Subsequent to December 31, 2011, Callon completed two acreage acquisitions within the northern portion of the Permian Basin's Midland Basin in Borden County. Together, these acquisitions included a total of 16,020 gross exploratory acres (14,470, net), and significantly increased the Company's acreage position in the Permian Basin by 152% to a total of 24,010 net acres compared to 9,540 net acres held at year-end 2011. For additional information regarding subsequent events, see Note 19 to the Consolidated Financial Statements.

Recent Accounting Standards

Various accounting standards and interpretations were issued in 2011 with effective dates subsequent to December 31, 2011. We have evaluated the recently issued accounting pronouncements that are effective in 2012 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.

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. 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. Based on projected annual sales volumes for 2012, excluding production from 2012 exploratory drilling and the effects of the Company's hedging program, a 10% decline in the NYMEX price of crude oil and natural gas would reduce our revenues by approximately $5.2 million and $1.7 million, respectively.

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While the Company does not enter into derivative transactions for speculative purposes, in order to limit its exposure to this risk, the Company most often utilizes price "collars" to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the 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.

The Company may also enter into derivative financial instruments including fixed price “swaps.” These swaps reduce our exposure to decreases in commodity prices, while simultaneously limiting the benefit the Company might otherwise have received from any increases in commodity prices. Similarly, the Company’s derivatives policy also allows Callon to, at its discretion, purchase “puts,” which reduce our exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counter-party pays the difference to the Callon.

During 2011, all of the Company’s derivative positions were designated as cash flow hedges for accounting purposes, though the Company has the discretion not to designate its hedges as such. See Note 7 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2011.

Interest Rate Risk

On December 31, 2011, all of the Company’s debt, consisting entirely of its 13% Senior Notes, had fixed interest rates. The Company’s revolving credit facility with Regions Bank includes a variable interest rate, and as such fluctuates based on short-term interest rates. Although the Company had no borrowings outstanding at December 31, 2011 under its revolving credit facility, were the Company to fully draw its available $45 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 $0.5 million. For additional information, see Note 6 to the Consolidated Financial Statements additional information regarding the Company’s credit facility and other borrowings at December 31, 2011.

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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, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2010, the Company changed its accounting for its subsidiary, Callon Entrada Company, as a result of adopting the amended accounting pronouncement related to the consolidation of variable interest entities. In 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

As discussed in Note 1 to the consolidated financial statements, the 2009 and 2010 consolidated financial statements have been restated to correct an error as a result of the Company's inappropriate application of the accounting guidance related to intraperiod tax allocation for its income tax provision for the year ended December 31, 2009.

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, 2011, 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, 2012, expressed an adverse opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 15, 2012

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

	December, 31 2011	2010 Restated
ASSETS		
Current assets:		
Cash and cash equivalents	$43,795	$17,436
Accounts receivable	15,181	10,728
Fair market value of derivatives	2,499	—
Other current assets	1,601	2,180
Total current assets	63,076	30,344
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,421,640	1,316,677
Less accumulated depreciation, depletion and amortization	(1,208,331)	(1,155,915)
Net oil and natural gas properties	213,309	160,762
Unevaluated properties excluded from amortization	2,603	8,106
Total oil and natural gas properties	215,912	168,868
Other property and equipment, net	10,512	3,370
Restricted investments	3,790	4,044
Investment in Medusa Spar LLC	9,956	10,424
Deferred tax asset	63,496	—
Other assets, net	718	1,276
Total assets	$367,460	$218,326
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$26,057	$17,702
Asset retirement obligations	1,260	2,822
Fair market value of derivatives	—	937
Total current liabilities	27,317	21,461
13% Senior Notes:		
Principal outstanding	106,961	137,961
Deferred credit, net of accumulated amortization of $13,123 and $3,964, respectively	18,384	27,543
Total 13% Senior Notes (See Note 6)	125,345	165,504
Asset retirement obligations	12,678	13,103
Other long-term liabilities	3,165	2,448
Total liabilities	168,505	202,516
Stockholders' equity:		
Preferred Stock, $.01 par value, 2,500,000 shares authorized;	—	—
Common Stock, $.01 par value, 60,000,000 shares authorized; 39,398,416 and 28,955,512 shares outstanding at December 31, 2011 and 2010, respectively	394	290
Capital in excess of par value	324,474	248,160
Other comprehensive (loss) income	1,624	(937)
Retained deficit	(127,537)	(231,703)
Total stockholders' equity	198,955	15,810
Total liabilities and stockholders' equity	$367,460	$218,326

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,		
	2011	2010	2009
Operating revenues:			Restated
Oil sales	$100,962	$65,243	$73,842
Natural gas sales	26,682	24,639	27,417
BOEM royalty recoupment (See Note 16)	—	—	40,886
Total operating revenues	127,644	89,882	142,145
Operating expenses:			
Lease operating expenses	20,347	17,712	18,447
Depreciation, depletion and amortization	48,701	31,805	33,443
General and administrative	16,636	16,507	13,355
Accretion expense	2,338	2,446	3,149
Acquisition expense	—	233	298
Total operating expenses	88,022	68,703	68,692
Income from operations	39,622	21,179	73,453
Other (income) expenses:			
Interest expense	11,717	13,312	19,089
Callon Entrada non-recourse credit facility interest expense (See Note 3)	—	—	7,072
(Gain) loss on early extinguishment of debt	(1,942)	339	—
Gain related to acquired assets, net (See Note 3)	(5,041)	—	—
9.75% Senior Notes restructuring expenses	—	—	1,024
Interest on BOEM royalty recoupment	—	(91)	(7,681)
Other (income) expense, net	(1,426)	(166)	190
Total other expenses, net	3,308	13,394	19,694
Income before income taxes	36,314	7,785	53,759
Income tax (benefit) expense	(67,036)	(174)	7,623
Income before equity in earnings of Medusa Spar LLC	103,350	7,959	46,136
Equity in earnings of Medusa Spar LLC	799	427	660
Net income available to common shares	$104,149	$8,386	$46,796
Net income per common share:			
Basic	$2.75	$0.29	$2.12
Diluted	$2.70	$0.28	$2.11
Shares used in computing net income per common share:			
Basic	37,908	28,817	22,072
Diluted	38,582	29,476	22,200

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, 2008	$—	$216	$227,803	$ 14,157	$(371,980)	$(129,804)
Comprehensive income:						
Net income (Restated)	—	—	—	—	46,796	
Other comprehensive loss (Restated)	—	—	—	(14,012)	—	
Total comprehensive income						32,784
Shares issued pursuant to employee benefit plans	—	1	205	—	—	206
Restricted stock	—	1	4,432	—	—	4,433
Common stock issued for Note exchange	—	69	11,458	—	—	11,527
Balance at December 31, 2009 (Restated)	$—	$287	$243,898	$ 145	$(325,184)	$(80,854)
Deconsolidation of subsidiary (See Note 3)	—	—	—	—	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 (Restated)	$—	$290	$248,160	$ (937)	$(231,703)	$15,810
Comprehensive income:						
Net income	—	—	—	—	104,149	
Other comprehensive income (See Note 5)	—	—	—	2,561	—	
Total comprehensive income						106,710
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 (See Note 3)	—	—	—	—	17	17
Balance at December 31, 2011	$—	$394	$324,474	$ 1,624	$(127,537)	$198,955

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,		
	2011	2010	2009
Cash flows from operating activities:			Restated
Net income	$104,149	$8,386	$46,796
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	49,753	32,629	34,274
Accretion expense	2,338	2,446	3,149
Amortization of non-cash debt related items	461	397	2,816
Amortization of deferred credit	(3,155)	(3,670)	(294)
Equity in earnings of Medusa Spar LLC	(799)	(427)	(660)
Deferred income tax benefit	13,175	1,503	18,816
Valuation allowance	(80,211)	(1,503)	(11,193)
Non-cash interest expense for Callon Entrada non-recourse credit agreement	—	—	3,693
Non-cash gain on acquired assets	(4,995)	—	—
Non-cash (gain) charge for early debt extinguishment	(1,942)	339	—
Non-cash charge related to compensation plans	2,098	3,107	2,335
Payments to settle asset retirement obligations	(2,563)	(2,486)	(6,657)
Changes in current assets and liabilities:			
Accounts receivable	(3,734)	59,527	(45,573)
Other current assets	180	(209)	(468)
Current liabilities	4,695	907	(27,260)
Change in natural gas balancing receivable	252	347	279
Change in natural gas balancing payable	(115)	(300)	(312)
Change in other long-term liabilities	100	(115)	(12)
Change in other assets, net	(520)	(776)	(31)
Cash provided by operating activities	79,167	100,102	19,698
Cash flows from investing activities:			
Capital expenditures	(100,243)	(59,908)	(29,133)
Acquisitions	—	(995)	(15,756)
Proceeds from sale of mineral interests	7,615	—	—
Investment in restricted assets related to plugging and abandonment	(150)	(375)	—
Distribution from Medusa Spar LLC	1,267	1,540	1,700
Cash used in investing activities	(91,511)	(59,738)	(43,189)
Cash flows from financing activities:			
Increases in senior secured facility	—	—	20,337
Payments on senior secured facility	—	(10,000)	(10,337)
Redemption of remaining 9.75% senior notes	—	(16,212)	—
Redemption of 13% senior notes	(35,062)	—	—
Issuance of common stock	73,765		
Proceeds from exercise of employee stock options	—	(40)	—
Cash provided by (used in) financing activities	38,703	(26,252)	10,000
Net change in cash and cash equivalents	26,359	14,112	(13,491)
Cash and cash equivalents:			
Balance, beginning of period	17,436	3,635	17,126
Less: Cash held by subsidiary deconsolidated at January 1, 2010	—	(311)	—

Balance, end of period	$43,795	$17,436	$3,635

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