CALLON PETROLEUM CO
Form 10-K
March 15, 2011

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

Form 10-K

for the year ended

December 31, 2010

| | |
|---|---|
| [X] | Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2010 |
| | 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 | 64-0844345 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 200 North Canal Street | |
| Natchez, Mississippi | 39120 |
| (Address of principal executive offices) | (Zip Code) |

601-442-1601
(Registrant's telephone number, including area code)

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

| Title of each class: | Name of each exchange on which registered: |
|---|---|
| Common Stock, $.01 par value | New York Stock Exchange |

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 [ ] 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 $165.3 million as of June 30, 2010.

As of March 3, 2011, 39,105,130 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, 2010) relating to the Annual Meeting of Stockholders to be held on May 12, 2011, 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 growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

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

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

- the timing and extent of changes in market conditions and prices for commodities (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to fund our planned capital investments;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
-

conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;

- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission ("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, 2010 (the "2010 Annual Report on Form 10-K"), 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
- B/d: barrels of oil or natural gas liquids per day.
- Bbl or Bbls: barrel or barrels of oil.
- 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.
- Boe/d: boe per day.
- BOEMRE: Bureau of Ocean Energy Management, Regulation and Enforcement; formerly the Minerals Management Service ("MMS")
- Btu: a British thermal unit, a measure of heating value, which is approximately equal to one Mcf.
- LIBOR: London Interbank Offered Rate.
- LNG: liquefied natural gas.
- Mbbls: thousand barrels of oil.
- Mboe: thousand boe.
- Mboe/d: Mboe per day.
- Mcfe: thousand cubic feet of natural gas.
- Mcf/d: Mcf per day.
- MMbbls: million barrels of oil.
- MMboe: million boe.
- MMBtu: million Btu.
- MMBtu/d: MMBtu per day.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- NGL or NGLs: natural gas liquids, which are expressed in barrels.
- NYMEX: New York Mercantile Exchange.
- Oil: includes crude oil and condensate.
- PDP: proved developed reserves.
- PUD: proved undeveloped reserves.
- SEC: United States Securities and Exchange Commission.
- Section: land area containing 640 acres
- 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 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 unl the context requires otherwise.

Callon Petroleum Company is engaged in the development, production, exploration and acquisition of oil and gas properties. In late 2008, our management shifted our operational focus from exploration in the Gulf of Mexico to the acquisition and development of onshore properties located in the Wolfberry play of the Permian Basin in Texas and the Haynesville Shale area in Louisiana. As of December 31, 2010, we had estimated net proved reserves of 8.1 MMBbls and 33.0 Bcf, or 13.6 MMBOE. Of these reserves, approximately 50.0% were located onshore in the Permian Basin Wolfberry and Haynesville Shale plays, compared with 16.5% located onshore at December 31, 2009.

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 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 barrel of oil equivalent ("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 at year-end 2010:

- We have a substantial inventory of onshore drilling locations, with an estimated 132 net drilling locations on 40-acre spacing and an additional 166 net drilling locations on 20-acre spacing in the Wolfberry play of the Permian Basin and four net locations in the Haynesville area.
- Our offshore properties generate substantial cash flow, which we can deploy in the acquisition, exploration and development of onshore properties.
- 

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

- On December 31, 2010, our total liquidity position was approximately $47 million, including $17 million of available cash and $30 million of unused borrowing base available under our senior secured credit facility. The borrowing base was increased by 50.0% over its previous level at the last redetermination in the fourth quarter of 2010. The next redetermination is scheduled for April 2011.

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Recent Developments

As discussed in Note 19 included in Part II, Item 8 of this filing, during February 2011, we received $73.7 million in net proceeds through the public offering of 10.1 million shares of our common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. Immediately following the completion of the equity offering, we called for redemption $31.0 million principal amount of our 13% senior notes due 2016. We expect to complete the redemption of these notes by March 19, 2011, which will result in a gain on the early extinguishment of debt of approximately $2.0 million. We also completed an arbitration proceeding with our former joint interest partner in the Entrada project, which is more fully discussed in Note 19.

Exploration and Development Activities

During 2010, capital expenditures on an accrual basis for exploration and development costs related to oil and gas properties included these expenditures (in millions):

| | |
|---|---|
| 20 wells drilled, 11 wells producing, on the Permian Basin acreage | $32.0 |
| Natural gas well in the Haynesville Shale gas play and site development for future wells | 10.9 |
| Leasehold acquisitions and seismic | 4.0 |
| Costs incurred on legacy properties | 1.6 |
| Plugging and abandonment costs in the Gulf of Mexico | 2.4 |
| Capitalized interest ($2.0 million) and overhead ($11.8 million) allocable directly to exploration and development projects. | 13.8 |
| Total 2010 capital expenditures (a) | $64.7 |

(a) The above costs exclude approximately $6.6 million of capital costs incurred on legacy properties as a result of certain joint interest billings not being recovered from a joint interest partner. Under the full-cost method of accounting, these costs are capitalized to the Company's full cost pool. Inclusive of this amount, 2010 capital expenditures totaled $71.2 million. See Note 19 included in Part II, Item 8 of this filing for additional information regarding the write-off of certain receivables.

As a result of the previously discussed shift in our operational focus from offshore in the Gulf of Mexico to onshore in the Wolfberry play of the Permian Basin and the Haynesville Shale play, we expect that substantially all of our 2011 capital expenditures will be focused on the development and acquisition of onshore properties in the United States, with only limited amounts of capital expended to maintain our offshore properties. Our projected 2011 capital expenditures budget is outlined within Management's Discussion and Analysis and Results of Operations, which is included in Part II, Item 7 of this filing.

Acquisitions and Divestitures

The Company increased its interest in the East Bloxom Development Area of the Permian Basin, located in Upton County, from an average 47% working interest to 100% working interest through a number of acquisitions and farm-ins for which the Company paid approximately $1.0 million during 2010, of which $0.1 million was recorded acquisition expenses during 2010. As a result, Callon now controls the activity in three development areas encompassing 11 Sections.

Oil and Gas Properties

As of December 31, 2010, our estimated net proved reserves totaled 13.6 MMBoe and included 8.1 MMBbls and 33.0 Bcf, with a pre-tax present value, discounted at 10%, of $205.5 million. Pre-tax present value may be deemed to be a non-US GAAP financial measure, which we reconcile to the US GAAP standardized measure of $198.9 million in the proved reserves table presented later within this section of the filing. Oil constitutes approximately 60% on an equivalent basis of our total estimated net proved reserves, and approximately 49% of our total estimated proved reserves are proved developed reserves.

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The following table sets forth certain information about our estimated proved reserves by our independent petroleum reserve engineers by major field and for all other properties combined at December 31, 2010:

| | Operator | Estimated Net Proved Reserves Oil (MBbls) | Gas (MMcf) | Total (MBoe) (a) | Pre-tax Discounted Present Value ($000) (b)(c)(d) |
|---|---|---|---|---|---|
| Onshore: | | | | | |
| Permian Basin | Callon | 3,410 | 6,247 | 4,451 | $41,438 |
| Haynesville Shale | Callon | - | 13,621 | 2,270 | 7,369 |
| Total Onshore | | 3,410 | 19,868 | 6,721 | 48,807 |
| | | | | | |
| Gulf of Mexico Deepwater: | | | | | |
| Mississippi Canyon 538/582 “Medusa” | Murphy | 4,020 | 3,011 | 4,522 | 125,678 |
| Garden Banks Block 341 “Habanero” | Shell | 642 | 4,592 | 1,408 | 28,411 |
| Total Gulf of Mexico Deepwater | | 4,662 | 7,603 | 5,930 | 154,089 |
| | | | | | |
| Gulf of Mexico Shelf and Other: | | | | | |
| West Cameron Block 295 | Mariner Energy | 8 | 1,466 | 253 | 4,714 |
| East Cameron Block 109 | Energy Partners LTD | 13 | 928 | 167 | 3,056 |
| East Cameron Block 2 | Apache | 8 | 770 | 136 | 2,572 |
| East Cameron Block 257 | SPN Resources | 1 | 899 | 150 | 1,906 |
| Other | Various | 47 | 1,423 | 284 | (9,612 ) |
| Total Gulf of Mexico Shelf and Other | | 77 | 5,486 | 990 | 2,636 |
| | | | | | |
| Total Net Proved Reserves | | 8,149 | 32,957 | 13,641 | $205,532 |

(a) We convert Mcf to Boe using a conversion ratio of six Mcf to one Boe. This ratio, which is typical in the industry and represents the approximate energy equivalent of an Mcf to a Boe, does not reflect to economic equivalency of an Mcf of gas compared with a Boe of oil or natural gas liquids. On an economic basis, a barrel of oil 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, 2010, 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, 2010, in accordance with accounting for asset retirement obligations rules. See the Oil and Gas Reserve table for the standardized measure of discounted future net cash flow in Note 15 of our consolidated financial statements. The negative Pre-Tax Present Value of the “Other” reflects plugging and abandonment obligations exceeding the future net cash flows, obligations of which most are 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, 2010 was $198.9 million inclusive of the $6.6 million discounted estimated future income taxes relating to such future net revenues. Year-end average pricing was $5.10 per Mcf for natural gas and $78.07 per Bbl for oil.

Onshore Properties

Onshore proved reserves accounted for approximately 50% of year-end 2010 proved reserves, demonstrating our progress toward our strategic goal of diversifying our reserve portfolio.

Permian Basin

During the fourth quarter of 2009, Callon acquired an interest in Permian Basin properties, which included 22 producing wells with associated proved reserves of 1.6 MMBoe. During 2010, the Company drilled an additional 20 wells targeting the Wolfberry trend, of which 11 were producing by year-end, thereby increasing total average daily production in the Permian Basin to approximately 550 boe/d as of December 31, 2010. The remaining 9 wells drilled during 2010 are scheduled to be fracture stimulated and brought online during the first and second quarters of 2011. Early in 2011, we entered into an agreement with our fracture stimulation service provider providing for a minimum of three well stimulations per month in 2011. During 2011, the Company plans to drill up to an additional 44 wells.

The Company's primary target in the Permian Basin is the Wolfberry play, which is located in Crockett, Ector, Midland and Upton Counties, Texas. This play is a proven, low-permeability oil play and includes the Sprayberry, Dean, and Wolfcamp formations. The Company currently owns approximately 8,800 net acres within the Permian Basin, approximately 80% of which is prospective for the Wolfberry Play and provides a drilling inventory of 132 additional drilling locations based on a 40-acre spacing development. Approximately 33% of our 2010 proved reserves were attributable to our properties in the Wolfberry play of the Permian Basin.

Haynesville Shale

During the third quarter of 2009, Callon acquired a 69% working interest in a Haynesville Shale unit located in Southern Bossier Parish, Louisiana, and currently owns approximately 430 net acres in the Haynesville Shale. Initial production from the George R. Mills Well No. 1H, our first well completed since acquiring this property in 2009, commenced on September 3, 2010. To date as of March 2011, the well has produced 1.4 billion cubic feet of natural gas and is currently producing at a restricted rate of 5.0 MMcfe/d. We have an additional four net drilling locations on the 430-net acre unit in which we have a 69% working interest. The Company also performed some site development work for future wells and is awaiting improvement in natural gas prices before resuming development of the field. Approximately 17% of our year-end 2010 proved reserves were attributable to our Haynesville Shale property.

Gulf of Mexico Deepwater Properties

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater discovery that occurred during 1999, 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.

During 2010 the Medusa field produced 593 MBoe net to us from eight wells which accounted for 35% of our total production. Most of the wells are still producing from their initial completions and have 2.4 MMBoe of proved developed non-producing reserves that will be accessed by recompletions in the existing wells. Another 1.2 MMBoe of proved undeveloped reserves will be developed by side tracking an existing well. These operations will occur as existing completions reach their economic limit, which as of December 31, 2010 is estimated to be in 2022.

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 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Off-Balance Sheet Arrangements."

Habanero, Garden Banks Block 341

The Habanero property, in which we own an 11.25% working interest in its wells, 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 and from the Habanero 55 gas sand in January 2004. The well is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest owned by Murphy.

During 2010, Habanero produced 232 MBoe net to us from two wells which accounted for 14% of our total production. Future plans include sidetracks of both the wells to drain updip and partially fault-separated gas in the Habanero 52 sand when the existing completions reach their economic limit, which is estimated as of December 31, 2010 to be in 2012 for one well and 2013 for the other.

Gulf of Mexico Shelf and Other Properties

We own interests in 18 producing wells in twelve oil and gas fields in the shelf area of the Gulf of Mexico. These wells produced 616 MBOE net to our interest in 2010, which accounted for 37% of our total production.

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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 and 2010 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 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 proved reserves. All of our proved reserves are located in the continental United States and in federal and state waters in the Gulf of Mexico.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Proved developed: | | | |
| Oil (MBbls) | 4,503 | 4,346 | 4,663 |
| Gas (MMcf) | 12,715 | 12,301 | 13,463 |
| MBoe | 6,622 | 6,396 | 6,907 |
| Proved undeveloped: | | | |
| Oil (MBbls) | 3,645 | 2,133 | 1,364 |
| Gas (MMcf) | 20,241 | 6,802 | 5,189 |
| MBoe | 7,019 | 3,266 | 2,229 |
| Total proved: | | | |
| Oil (MBbls) | 8,149 | 6,479 | 6,027 |
| Gas (MMcf) | 32,957 | 19,103 | 18,652 |
| MBoe | 13,641 | 9,663 | 9,136 |
| Estimated pre-tax future net cash flows (a) | $379,448 | $216,702 | $113,555 |
| Pre-tax discounted present value (a) (b) | $205,532 | $137,368 | $86,591 |

| | | | |
|---|---|---|---|
| Standardized measure of discounted future net cash flows(a) (b) | $198,916 | $135,921 | $86,305 |

(a)Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2010, in accordance with accounting for asset retirement obligations rules.

(b)The Company uses the financial measure "Pre Tax Present Value" which is a non-US GAAP financial measure. The Company believes that Pre Tax 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, 2010 was $198.9 million inclusive of the $6.6 million discounted estimated future income taxes relating to such future net revenues. Year-end average pricing was $5.10 per Mcf for natural gas and $78.07 per Bbl for oil.

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

The Company reviews annually its PUDs to ensure an appropriate plan exists for development. Generally, reserves for onshore properties 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 following table summarizes the Company's recorded PUDs:

| | PUDs (in MBoe) at December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Permian Basin | 2,928 | 932 | - |
| Haynesville Shale | 1,757 | - | - |
| Total Onshore PUDs | 4,685 | 932 | - |
| Medusa | 1,186 | 1,186 | 1,081 |
| Habanero | 1,148 | 1,148 | 1,148 |
| Total Deepwater PUDs | 2,334 | 2,334 | 2,229 |
| Total Shelf and other PUDs | - | - | - |
| Total PUDs | 7,019 | 3,266 | 2,229 |

Our plans are to develop our deepwater PUDS by side tracking existing wells when the zones currently being produced by the wells are depleted. The Company's current plans forecast that the two producing zones in the Habanero field will be depleted one in 2012 and the other in 2013. In the Medusa field, the Company expects several recompletes to occur prior to 2012 with current producing reserves forecasted to reach their economic depletion point in 2022. Upon the depletion of currently producing reserves, the Company plans to develop its deepwater PUDs. During 2010, Callon did not convert any offshore PUDs to PDPs. The Company's plans to develop its PUDs in the Permian Basin include a multi-year drilling program, which is expected to be completed on existing acreage within three to five years. Similarly, the Company plans to resume drilling on its Haynesville Shale property once gas prices improve, and expects to convert its existing PUDs within the next five years.

From December 31, 2009 to December 31, 2010, our PUDs increased 115% from 3,266 MBOE to 7,019 MBOE. As a result of acquisitions during 2009, we added 932 MBoe as compared to 2008. We then added 3,752 MBoe as a result of successful drilling during 2010 and commensurate PUDs associated with such drilling. None of these additions to our PUD reserves were offset by amounts no longer deemed to be economic PUDs at year-end. At January 1, 2010, we had 3,266 MBOE of proved undeveloped reserves. Of these PUD reserves, 23% were converted to proved developed producing reserves by year end 2010, at a total cost of $6.4 million, net.

We plan to develop our proved undeveloped reserves within a five-year time frame. The basis for our development plans are (i) allocation of capital to projects in our 2011 capital budget and (ii) in subsequent years, on the basis of capital allocation in our five-year 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.

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 with over 30 years of industry experience including 25 years as a manager, 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, which 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 and being a member of the Society of Petroleum Engineers.

The Audit Committee of our 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 gas reserves.

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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.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| | (in thousands, except per unit data) | | |
| Production | | | |
| Natural gas (Mcf) | 4,892 | 5,740 | 5,839 |
| Oil (MBbl) | 859 | 1,012 | 942 |
| Total (MBoe) | 1,674 | 1,969 | 1,915 |
| Revenues | | | |
| Natural gas sales | $24,639 | $27,417 | 58,349 |
| Oil sales | 65,243 | 73,842 | 82,963 |
| Total revenues | $89,882 | $101,259 | $141,312 |
| Lease Operating Expenses | | | |
| Production costs | $16,094 | $16,778 | $17,605 |
| Severance/production taxes | 816 | 528 | 626 |
| Gathering | 802 | 1,141 | 977 |
| Total lease operating expenses | $17,712 | $18,447 | $19,208 |
| Realized prices | | | |
| Natural gas ($/Mcf, including realized gains (losses) on derivatives) | $5.04 | $4.78 | $9.99 |
| Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) | 4.91 | 4.45 | 10.10 |
| Oil ($/Bbl, including realized gains (losses) on derivatives) | 75.97 | 73.00 | 88.07 |
| Oil ($/Bbl, excluding realized gains (losses) on derivatives) | 75.97 | 55.84 | 97.37 |
| Operating costs per Boe - Total Consolidated | | | |
| Production costs | $9.61 | $8.52 | $9.19 |
| Severance/production taxes | 0.49 | 0.27 | 0.33 |
| Gathering | 0.48 | 0.58 | 0.51 |
| DD&A | 19.00 | 16.99 | 33.45 |
| Interest | 7.95 | 9.70 | 12.52 |
| Total operating costs per Boe | $37.53 | $36.06 | $56.00 |

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Present Activities and Productive Wells

The following table sets forth the wells drilled and completed during the periods indicated. All such wells were drilled in the continental United States and in federal and state waters in the Gulf of Mexico. At December 31, 2010 we had nine oil wells awaiting fracture stimulation and were in the process of drilling two wells.

| | Years ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2010 | | 2009 | | 2008 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development: | | | | | | |
| Oil | 4 | 3.69 | - | - | 1 | 0.15 |
| Gas | - | - | - | - | - | - |
| Non-productive | - | - | - | - | 1 | 0.50 |
| Total | 4 | 3.69 | - | - | 2 | 0.65 |
| | | | | | | |
| Exploration: | | | | | | |
| Oil | 16 | 15.69 | - | - | - | - |
| Gas | 1 | 0.69 | - | - | - | - |
| Non-productive | - | - | - | - | 2 | 0.22 |
| Total | 17 | 16.38 | - | - | 2 | 0.22 |

The following table sets forth productive wells as of December 31, 2010:

| | Oil Wells | | Gas Wells | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Working interest | 45 | 32.02 | 21 | 7.87 |
| Royalty interest | 3 | 0.10 | 6 | 0.15 |
| Total | 48 | 32.12 | 27 | 8.02 |

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to gas reserves on a Mcfe basis. However, some of our wells produce both oil and gas. At December 31, 2010, we had no wells with multiple completions.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2010. A portion of our Texas acreage requires continued drilling to hold the acreage for which we have included in our development plans, though the renewal of this acreage, if necessary, is not considered material. We have two federal blocks in offshore waters, 11,520 gross or 8,446 net acres, which will expire within the next two years for which we have a carrying value of $3.5 million. We are currently negotiating potential farm-outs of this acreage. In addition we have three other federal blocks in offshore waters, 16,706 gross or 6,489 net acres, scheduled to expire within the next two years which have no carrying value and for which we have no current development plans.

| | Developed | | Undeveloped | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Louisiana | 4,848 | 2,339 | 931 | 699 |
| Texas | 6,160 | 5,520 | 3,634 | 3,306 |
| Federal onshore | - | - | 64,963 | 64,963 |
| Federal waters | 53,211 | 18,386 | 72,955 | 41,919 |
| Total | 64,219 | 26,245 | 142,483 | 110,887 |

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Title to Properties

The Company believes that the title to its oil and 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 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, the characteristic has 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 it's conventional in the industry for properties of the kind owned by Callon.

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 gas production during each of the 12-month periods ended:

| | Percentage of Total Revenue for the year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Shell Trading Company | 44% | 45% | 33% |
| Plains Marketing, L.P. | 20% | 23% | 23% |
| Louis Dreyfus Energy Services | 13% | 15% | 16% |
| Other | 23% | 17% | 28% |
| Total | 100% | 100% | 100% |

Because alternative purchasers of oil and 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 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 79 employees as of December 31, 2010, which included eight petroleum engineers and four petroleum geoscientists.  None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

Regulations

General.  The oil and 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.  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 wells,
- the rate and method of production,
- the surface use and restoration of properties upon which wells are drilled and other exploration activities,
- 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 outer continental shelf ("OCS") leases in federal waters are administered by Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), and require compliance with detailed BOEMRE (a) regulations and orders. Lessees must obtain BOEMRE 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 BOEMRE has 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 BOEMRE has 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 BOEMRE regulations restrict the flaring or venting of natural gas, and prohibit the flaring of liquid hydrocarbons and oil without prior authorization. The BOEMRE is considering whether to require flaring rather than venting, where practical, to reduce the potential effect of greenhouse gas emissions.

BOEMRE 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 BOEMRE has 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, BOEMRE 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, BOEMRE 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 gas exploration and production on the OCS. Especially with respect to deepwater operations, the BOEMRE has issued rules that are more stringent than the rules issued by the MMS, and has announced its 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 gas exploration and production on the OCS. In addition, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, whose members were appointed by President Obama, issued a report proposing, among other things, fundamental reform of the regulation of oil and 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 BOEMRE 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.

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In response to concerns that the former Minerals Management Service's ("MMS") revenue-generating and resource development functions were at odds with its safety and environmental regulatory functions, the Department of Interior plans to divide the BOEMRE into three separate agencies: the Bureau of Ocean Energy Management ("BOEM"), to be the resource manager for conventional and renewable energy and mineral resources on the OCS; the Bureau of Safety and Environmental Enforcement ("BSEE"), to promote and enforce safety in offshore energy exploration and production operations; and the Office of Natural Resources Revenue ("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. The ONRR began operations on October 1, 2010. The BOEM and the BSEE are scheduled to undergo a phased implementation program beginning in January 2011 and continuing for at least twelve months.

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, 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. 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.

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.

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 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 Environmental Protection Agency ("EPA") has been moving forward with rulemaking to regulate GHGs as pollutants under the Clean Air Act ("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 -- for 2010 -- being due in March of 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, e.g., 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.

Application of the Safe Drinking Water Act to Hydraulic Fracturing. Congress is currently considering 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 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 bills pending before the Senate and House of Representatives 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. 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.

Surface Damage Statues ("SDAs"). In addition, eleven states 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 laws 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.

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 Bureau of Land Management, BOEMRE or other appropriate federal or state 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 Securities and Exchange Commission (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

Future economic conditions in the U.S. and key international markets may materially adversely impact our operating results. The U.S. and other world economies are slowly recovering from a recession that began in 2008 and extended through 2010. While modest growth has resumed, there are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than we have experienced in recent years. In addition, more volatility may occur before a sustainable growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

Depressed oil and gas prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and gas, which are extremely volatile, and the oil and gas markets are cyclical. Extended periods of low prices for oil or gas will have a material adverse effect on us. The prices of oil and 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 gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and 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 gas properties.

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 40% of our estimated net proved reserves are natural gas, and 49% of our production in 2010 was natural gas. A sustained reduction in natural gas prices could have an adverse effect on our results of operation and financial condition.

Our actual recovery of reserves may substantially differ from our proved reserve estimates. This Form 10-K contains estimates of our proved oil and 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 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 gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and 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 gas prices and quality and locational differences; and
- Future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual results could vary considerably from estimated quantities of proved natural gas and oil reserves (in the aggregate and for a particular geographic location), production, revenues, taxes and development and operating expenditures. Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and US GAAP. We provide information about our oil and gas properties, including production profiles, prices and costs, to our independent reserve engineer and they prepare their own estimates of the reserve attributable to our properties.

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, 2010 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, 2010, approximately 21% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 51% of total proved reserves by volume, and approximately 33% 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 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 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. Approximately 43% of our estimated proved reserves at December 31, 2010 and 49% of our production during 2010 were associated with our Gulf of Mexico, deep-water properties. 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. 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.

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 2010, approximately 62% of our daily production came from three 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, 2010, approximately 43% 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 gas activities. We may seek to replace reserves through exploration, where the risks are greater than in acquisitions and development drilling. 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 drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- overpressured formations and resultant blowouts or cratering;
- equipment failures or accidents;
- adverse weather conditions;
- governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

Our decision to drill a prospect is subject to a number of factors, and we may decide to alter our drilling schedule or not drill at all. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. Whether we ultimately drill a prospect may depend on the following factors:

- receipt of additional seismic data or other geophysical data or the reprocessing of existing data;

- material changes in oil or gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of our joint working interest owners; and
- changes to governmental regulations.

We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all. You should understand that our plans regarding our prospects are subject to change.

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 reservoirs 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 by us will be profitably developed, that new wells drilled by us 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. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively whether oil or natural gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

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. We intend to focus on producing property acquisitions that would preferably include undeveloped acreage. Integration of acquisitions with our existing business and operations will be a complex, time consuming and costly process. 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 Louisiana and Texas or other regions in the future. 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. Our recent growth is due significantly to acquisitions of producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. 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. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

There is competition for available oil and 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;
- 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 reduce the value of our non-operated properties.

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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 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; and
- because of these or other events, we could experience environmental hazards, including release of oil and gas from spills, gas leaks, 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 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 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 gas we produce. In addition, we may be unable to obtain favorable prices for the oil and gas we produce. These factors include:

- the extent of domestic production and imports of oil and gas;
- the proximity of the gas production to gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and 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 gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

In particular, in the Haynesville Shale and other nonconventional shale plays, 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, 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. Our experience with horizontal drilling in these areas to date, 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 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 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 the financial or personnel resources of the Company 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.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business. In 2009. the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act. Among other things, the act requires the Commodity Futures Trading Commission and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility. We cannot predict the content of these regulations or the effect that these regulations will have on our hedging activities. Of particular concern, the act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several Senators have indicated that it was not the intent of the act to require margin from end users, the exemption is not in the act. If the regulations ultimately adopted were to require that we post margin for our hedging activities, our hedging would become more expensive and we may decide to alter our hedging strategy. Additionally, it is possible that regulations, when finally adopted, in addition to increasing the expenses related to our hedging program may cause us to alter our hedging strategy.

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 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 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 gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference. Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. See "Quantitative and Qualitative Disclosures About Market Risks" for a discussion of our hedging practices.

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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 and greenhouse gases. 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 gas we produce. On December 15, 2009, the U.S. Environmental Protection Agency ("EPA") officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources.

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.

Both houses of the United States Congress have actively considered legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce GHG emission reduction levels that states sent out to achieve by specific time periods, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs work by requiring 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 reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGS associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

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

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. 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 a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been 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, a draft of which must be published by June 1, 2011, followed by a 30-day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements 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. 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. Among the changes contained in President Obama’s Budget Proposal for Fiscal Year 2012 is the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. The President’s budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, in which case only cost depletion would be available. It is unclear whether any such changes will be enacted or how soon any such changes could 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 our 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.

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ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

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

ITEM 4. Reserved

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 | |
|---|---|---|---|---|
| | 2010 | | High | Low |
| 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 |
| | | | | |
| | 2009 | | | |
| First quarter | ended | March 31, 2010 | $3.50 | $0.93 |
| Second quarter | ended | June 30, 2010 | 3.15 | 1.01 |
| Third quarter | ended | September 30, 2010 | 2.43 | 1.37 |
| Fourth quarter | ended | December 31, 2010 | 2.13 | 1.36 |

As of March 3, 2011 the Company had approximately 3,393 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 primary credit facility and the terms of our outstanding debt prohibit the payment of cash dividends on our common stock.

During the fourth quarter of 2010, 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, 2010 (securities amounts are presented in thousands).

Plan Category

| | Number of securities to be issued upon exercise of outstanding options | Weighted-average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance under equity compensation plans |
|---|---|---|---|
| Equity compensation plans approved by security holders | 124 | $ 11.46 | 754 |
| Equity compensation plans not approved by security holders | 74 | 6.44 | 27 |
| Total | 198 | 9.57 | 781 |

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, 2010, 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. Note that following Morningstar's acquisition of Hemscott, the Morningstar Group Index is replacing the Hemscott Industry and Market Index of SIC Group 123 (the "Hemscott Group Index"), which was included in the Company's performance graphs in prior filings. Consequently, both indexes have been included for comparative purposes during the transition to the Morningstar Group Index; and
- the New York Stock Exchange Market Index.

| Company/Market/Peer Group | 12/31/2005 | 12/31/2006 | 12/31/2007 | 12/31/2008 | 12/31/2009 | 12/31/2010 |
|---|---|---|---|---|---|---|
| Callon Petroleum Company | $100.00 | $85.16 | $93.20 | $14.73 | $8.50 | $33.54 |
| NYSE Composite Index | $100.00 | $120.47 | $131.15 | $79.67 | $102.20 | $115.88 |
| Morningstar Group Index | $100.00 | $94.73 | $126.71 | $47.87 | $72.96 | $68.36 |
| Hemscott Group Index | $100.00 | $118.43 | $186.25 | $83.39 | $158.52 | $149.20 |

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ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2010 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.

| | For the year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2010 | 2009 | 2008 | 2007 | 2006 |
| Statement of Operations Data: | (In thousands, except per share amounts) | | | | |
| Operating revenues: | | | | | |
| Oil and gas sales | $89,882 | $101,259 | $141,312 | $170,768 | $182,268 |
| Medusa BOEMRE royalty recoupment | - | 40,886 | - | - | - |
| Total operating revenues | $89,882 | $142,145 | $141,312 | $170,768 | $182,268 |
| Operating expenses: | | | | | |
| Non-impairment related operating expenses | $68,703 | $68,692 | $97,497 | $114,418 | $107,865 |
| Impairment of oil and gas properties | - | - | 485,498 | - | - |
| Total operating expenses | $68,703 | $68,692 | $582,995 | $114,418 | $107,865 |
| Income (loss) from continuing operations | 21,179 | 73,453 | (441,683) | 56,350 | 74,403 |
| Net income (loss) | 8,386 | 54,419 | (438,893) | 15,194 | 40,560 |
| | | | | | |
| Earnings (loss) per share ("EPS"): | | | | | |
| Basic | $0.29 | $2.47 | $(20.68) | $0.73 | $1.43 |
| Diluted | $0.28 | $2.45 | $(20.68) | $0.71 | $1.28 |
| Weighted average number of shares outstanding for Basic EPS | 28,817 | 22,072 | 21,222 | 20,776 | 20,270 |
| Weighted average number of shares outstanding for Diluted EPS | 29,476 | 22,200 | 21,222 | 21,290 | 21,363 |
| | | | | | |
| Statement of Operations Data: | | | | | |
| Net cash provided by operating activities | $99,942 | $19,698 | $89,054 | $109,283 | $135,484 |
| Net cash used in investing activities | (59,738) | (43,189) | (4,511) | (215,791) | (166,901) |
| Net cash provided by (used in) financing activities | (26,092) | 10,000 | (120,667) | (157,862) | 30,748 |
| | | | | | |
| Balance Sheet Data: | | | | | |
| Oil and gas properties, net | $168,868 | $130,608 | $159,252 | $681,706 | $547,027 |
| Total assets | 218,326 | 227,991 | 266,090 | 792,482 | 625,527 |
| Long-term debt (a) | 165,504 | 179,174 | 272,855 | 392,012 | 225,521 |
| Stockholder' equity (deficit) | 15,810 | (80,854) | (129,804) | 287,075 | 281,363 |
| | | | | | |
| Proved Reserves Data: | | | | | |
| Total Oil (MMBbls) | 8,148 | 6,479 | 6,027 | 24,531 | 13,265 |
| Total Gas (MMcf) | 32,956 | 19,103 | 18,652 | 116,454 | 66,037 |
| Total proved reserves (MBoe) | 13,641 | 9,663 | 9,136 | 43,940 | 24,271 |
| Present value of estimated future after-tax, net cash flows | $198,916 | $135,921 | $86,305 | $1,133,989 | $470,791 |

(a) Long-term debt includes a non-cash $27,543 deferred credit 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.

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 as a result of the ceiling test. See Note 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.

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

### General

The following management’s discussion and analysis is intended to assist in understanding the principal factors affecting the Company’s results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing.

We have been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Prior to 2009, our operations were focused on exploration and production in the Gulf of Mexico, and beginning in the latter part of 2008, we took steps to change our operational focus to lower risk, onshore exploration and development activities thereby reducing our reserve and production concentration in offshore properties.

### Overview and Outlook

During 2010, Callon had net income and fully diluted earnings per share of $8.4 million and $0.28, respectively, compared to net income of $54.4 million and fully diluted earnings per share of $2.45, respectively for 2009. Prior year results included a $44.8 million royalty recoupment, plus $7.7 million interest, from the BOEMRE for royalties paid during 2009 and prior years. 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 2010, Callon increased proved reserves by approximately 41%, increased Permian Basin oil production by 69%, brought online its first Haynesville gas well and diversified its net proved reserves with nearly 50% now being located onshore.

We made significant progress during 2010 towards our goal of strengthening our balance sheet and improving our liquidity, which better positions Callon for future growth. Significant financial achievements include:

- Including principal and interest through the repayment date, we received $52.7 million for recoupment of deepwater royalty payments made to the BOEMRE.
- The borrowing base of our Credit Facility was amended to provide for a $30 million borrowing base, representing a $10 million or 50% increase over the originally approved borrowing base. The underwriting bank approved the increase following its most recent borrowing base review based on the growth of the Company’s proved reserves, the collateral for the facility.
- We completed the redemption of the remaining $16.1 million outstanding of 9.75% Senior Notes (“Old Notes”) held by those note holders who did not participate in an exchange offered in teh fourth quarter of 2009. The redemption and the exchange of our Old Notes with 13% Senior Notes reduced by 25% the principal balance of our notes and extended the restructured notes’ maturity from 2010 to 2016 in exchange for a 3.25% increase in the coupon rate and equity consideration. Principal outstanding under the 13% Senior Notes due 2016 is approximately $138.0 million, a significant decrease from the $200 million principal formerly outstanding under the Old Notes. (See Note 6 and discussion below highlighting the planned early redemption of $31 million of 13% Senior Notes during March 2011)

During February 2011, the Company received $73.7 million in net proceeds through the public offering of 10.1 million shares of its common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. During March 2011, the Company intends to utilize approximately $35 million of the proceeds to redeem $31 million face value of its Senior Notes, plus the 13% call premium. The remaining proceeds from the offering are intended to fund a portion of our 2011 capital budget and for general corporate purposes, including possible future acquisitions.

Our success in these areas allows us to continue executing on our strategy to shift our operational focus from the offshore Gulf of Mexico to developing longer life, lower risk onshore properties. Our Permian Basin and Haynesville Shale onshore properties along with the cash flow from our Gulf of Mexico operations have already begun to re-shape our portfolio and outlook, and we believe that we are well positioned to continue diversifying our portfolio by building profitable growth opportunities onshore. During 2010, we began to develop the properties we acquired during late 2009. This 2010 development resulted in a 41% increase in total proved reserves, of which 50% were onshore.

- Onshore – Permian Basin

During the fourth quarter of 2009, we acquired interests in properties producing from the Permian Basin's Wolfberry and other formations in Crockett, Ector, Midland and Upton Counties, Texas. The acquisition included year-end proved reserves of 1.6 MMBoe, 22 existing wells producing approximately 325 Boe/d and upside from a multi-year inventory of drilling opportunities. We operate substantially all of the production and development of these properties. We currently own approximately 8,800 net acres in the Permian Basin with approximately 80% prospect for the Wolfberry.

During 2010, we drilled gross 20 wells in the Permian Basin targeting the Wolfberry, and placed on production 11 wells at a total cost of approximately $32.0 million. As a result of our 2010 development drilling activity, our net production has increased from 325 net Boe/d at the end of 2009 to 550 net Boe/d as of December 31, 2010, somewhat lower than our original expectations of 750 net Boe/d. The lower production relates primarily to delays in receiving fracture stimulation services, discussed below, for which there is increased demand in the area at the present time. Beyond 2010, and based on our current acreage holdings, our Permian acreage has the potential for an additional 132 wells based on 40-acre spacing.

As of December 31, 2010, we had nine wells awaiting fracture stimulation with the expectation that we will continue to build an inventory of wells waiting on fracture stimulation until the service organization builds additional capacity to handle industry requirements. As of March 1, 2011, three wells that were awaiting fracture stimulation as of December 31, 2010 have since been brought online. Early in 2011, we entered into an agreement with our fracture stimulation service provider providing for a minimum of three well stimulations per month in 2011. Either party to the agreement may cancel the agreement without penalty with at least 30 days notice. We expect to fracture stimulate three additional wells during the first quarter of 2011, and expect that our remaining year-end 2010 inventory of wells awaiting stimulation will be serviced by the second quarter of 2011. We plan to drill up to 44 gross wells during 2011, of which three had been drilled and two were in-process as of March 1, 2011.

In addition, during 2010 we have increased our interest in the East Bloxom Development Area, located in Upton County, from an average 47% working interest to a 100% working interest through a number of small acquisitions and farm-ins. As a result, we now control the activity in three development areas encompassing 11 sections.

- Onshore – Shale Gas (Haynesville Shale)

Also during the late 2009, we acquired a 69% working interest in a 624-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana. Our multi-year development plan for this property includes drilling and operating a total of seven gross or five net horizontal wells. The first of these wells was spud during June 2010, completed and placed on production in September 2010 and was producing, at a restricted rate, approximately 6,500 Mcfe/d as of December 31, 2010. The well cost approximately $10.9 million net to Callon, which included additional site development work for future 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 currently owns approximately 430 net acres in the Haynesville Shale.

Also highlighting the continued successful execution of our long-term strategy and as a result of an increase in our market capitalization to an amount above the minimum required threshold, on April 23, 2010 the New York Stock Exchange ("NYSE") removed Callon from its "Watch List" and affirmed that we are now considered a "company back in compliance" with the NYSE's quantitative continued listing standards.

Our onshore properties along with the strong cash flow from our Gulf of Mexico operations have strengthened our portfolio and outlook. We believe we are well positioned to continue the pursuit of diversifying our portfolio by building profitable growth opportunities onshore. Factors potentially impacting our expected production profile include:

- A reduced level of capital expenditures;
- Allocation of capital expenditures to acquire producing properties;
- Natural field decline in the deepwater Gulf of Mexico and Gulf Coast areas of our operations
- Timing of well completions in the Permian Basin and Haynesville Shale development programs;
- Potential hurricane-related downtime and volume curtailments in the Gulf of Mexico and Gulf Coast areas; and
- Inflation of capital costs and operating expenses.

Deconsolidation of Callon Entrada

During 2010 we adopted the newly issued accounting standard issued by the FASB in September 2009, which significantly modified our consolidated financial statements. Upon adoption, we reevaluated our interest in Callon Entrada, and based on the evaluation performed, we concluded that a variable interest entity ("VIE") reconsideration event had taken place. Our reconsideration analysis resulted in the determination that Callon Entrada is a VIE for which we are not the primary beneficiary. Consequently, effective January 1, 2010, Callon Entrada was deconsolidated from our consolidated financial statements. 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. For additional information regarding the deconsolidation of Callon Entrada, see Note 3, Deconsolidation of Callon Entrada, included in Item II, Part 8 of this filing.

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 $13.8 million during 2010 to $17.4 million compared to $3.6 million at December 31, 2009. The increase is primarily attributable to an $80.2 million increase in cash flows from operations, which included production increases from our newly acquired properties and higher realized, average commodity prices on an equivalent basis, and the receipt of the previously discussed $52.7 million BOEMRE royalty recoupment and related interest. These increases were partially offset by production declines on some legacy properties, a $16.5 million increase in cash used in investing activities and a $36.1 million increase in cash used in financing activities.

During 2010, we amended our Senior Secured Credit Agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated senior secured credit agreement ("the Credit Facility"), which matures on September 25, 2012, provides for a $100 million facility and has a current borrowing base of $30 million, which represents a $10 million or 50% increase over the original $20 million borrowing base. Regions Bank approved the increase following its fourth quarter 2010 redetermination review. The bank performs its redetermination reviews on a semi-annual basis. The Credit Facility bears interest at 4% above a defined base rate and in no event will the interest rate be less than 6%. As of December 31, 2010, the interest rate on the facility was 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. Simultaneously with the execution of the third amended and restated senior secured credit agreement, we repaid the $10 million then outstanding under the second amended and restated senior secured credit agreement. No amounts were outstanding under the amended facility as of December 31, 2010.

During the second quarter of 2010, we redeemed the remaining $16.1 million outstanding of our Old Notes, leaving only $138.0 million of the 13% Senior Notes outstanding at December 31, 2010. Following the previously discussed February 2011 equity offering from which the company received net proceeds of $73.7 million through the issuance of 10.1 million shares of its common stock, the Company intends to redeem during March 2011 $31 million of the 13% Senior Notes for approximately $35 million inclusive of the $4 million call premium. The remaining proceeds from the offering are to fund a portion of its 2011 capital budget and for general corporate purposes, including possible future acquisitions.

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2011 Budget and Capital Expenditures

For 2011, we designed a flexible capital spending program that can be funded from cash on hand, including the proceeds from the recent equity offering, and cash flows from operations. We believe these resources along with our Credit Facility, if needed, will be adequate to meet our capital, interest payments, and operating requirements for 2011. However, depending on commodity prices and other economic conditions we experience in 2010, this base capital program may be adjusted up or down. Inflation has not had a material impact on us, nor is it expected to have a material impact on us in the immediate future.

Our preliminary base capital program includes further development of our Permian Basin crude oil assets, with plans to drill approximately 44 additional gross oil wells during 2011. Our 2011 capital budget approximates $107 million, of which 81% is dedicated to our growth strategy, and also includes plugging and abandonment, capitalized interest and certain overhead costs related to acquiring, exploring and developing our oil and gas properties. Components of the 2011 capital budget include:

| | |
|---|---|
| Permian Basin / Wolfberry development | $77 |
| Leasehold related | 10 |
| Gulf of Mexico plugging and abandonment and maintenance capital expenditures | 8 |
| Capitalized interest and general and administrative costs | 12 |
| Total projected 2011 capital expenditures budget | $107 |

Should we identify an attractive strategic opportunity or acquisition, in addition to our available cash including the proceeds from the recent equity offering , we have a $30 million borrowing base available under our Credit Facility.

The following table includes the Company's contractual obligations and purchase commitments as of December 31, 2010, at which date the Company had no product delivery commitments:

| | | Payments due by Period | | | |
|---|---|---|---|---|---|
| Contractual Obligation & Purchase Commitments | Total | < 1 Year | 1 - 3 Years | 3 - 5 Years | >5 Years |
| 13% Senior Notes | $137,961 | - | - | $137,961 | - |
| Office space lease commitments | 2,972 | 26 | 458 | 684 | 1,804 |
| Medusa Oil Pipeline Throughput Commitment | 101 | 39 | 35 | 27 | - |
| Total | $141,034 | $65 | $493 | $138,672 | $1,804 |

Summary cash flow information is provided as follows:

Operating Activities. For the year ended December 31, 2010, net cash provided by operating activities was $99.9 million, an $80.2 million or 407% increase from net cash provided by operating activities of $19.7 million for the same period in 2009. The increase in net cash provided by operating activities was primarily attributable to receipt of the $52.7 million BOEMRE royalty recoupment including interest, production increases from our onshore properties and higher commodity prices on an equivalent basis, partially offset by production declines on some legacy properties.

Investing Activities. For the year ended December 31, 2010, net cash used in investing activities was $59.7 million as compared to $43.2 million for the same period in 2009. The $16.5 million increase, primarily attributable to an increase in capital expenditure spending, relates to drilling 20 wells in the Permian Basin properties and one well in the Haynesville Shale property. These increases were partially offset by the wind-down costs paid in 2009 for Callon Entrada with no similar costs paid during 2010.

Financing Activities. For the year ended December 31, 2010, net cash used in financing activities was $26.1 million compared to cash provided of $10.0 million for the same period in 2009. The 2010 expenditures related to the redemption of the $16.1 million remaining Old Notes and to the repayment of $10 million outstanding borrowings under the Credit Facility simultaneous with the amendment to include Regions Bank as the sole arranger and administrative agent.

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Results of Operations

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

| | For the year ended December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2010 | 2009 | $ Change | % Change | 2008 | $ Change | % Change |
| Net production: | | | | | | | |
| Oil (MBbls) | 859 | 1,012 | (153) | (15)% | 942 | 70 | 7% |
| Gas (MMcf) | 4,892 | 5,740 | (848) | (15)% | 5,839 | (99) | (2)% |
| Total production (MBoe) | 1,674 | 1,969 | (295) | (15)% | 1,915 | 54 | 3% |
| Average daily production (Boe) | 4,587 | 5,394 | (807) | (15)% | 5,247 | 147 | 3% |
| Average realized sales price (a): | | | | | | | |
| Oil (Bbl) | $ 75.97 | $ 73.00 | $ 2.97 | 4% | $ 88.07 | $ (15.07) | (17)% |
| Gas (Mcf) | 5.04 | 4.78 | 0.26 | 5% | 9.99 | (5.21) | (52)% |
| Total (Boe) | 53.69 | 51.44 | 2.25 | 4% | 73.79 | (22.35) | (30)% |
| Oil and gas revenues (in thousands): | | | | | | | |
| Oil revenue | $ 65,243 | $ 73,842 | $ (8,599) | (12)% | $ 82,963 | $ (9,121) | (11)% |
| Gas revenue | 24,639 | 27,417 | (2,778) | (10)% | 58,349 | (30,932) | (53)% |
| Total | $ 89,882 | $ 101,259 | $ (11,377) | (11)% | $ 141,312 | $ (40,053) | (28)% |
| Additional per Boe data: | | | | | | | |
| Sales price | $ 53.69 | $ 51.44 | $ 2.25 | 4% | $ 73.79 | $ (22.35) | (30)% |
| Lease operating expense | (10.58) | (9.37) | (1.21) | 13% | (10.03) | 0.66 | (7)% |
| Operating margin | $ 43.11 | $ 42.07 | $ 1.04 | 2% | $ 63.76 | $ (21.69) | (34)% |

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil:

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Average NYMEX oil | $ 79.52 | $ 61.80 | $ 17.72 | 29% | $ 99.67 | $ (37.87) | (38)% |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| price | | | | | | | |
| Basis differential and quality adjustments | (2.39) | (4.64) | 2.25 | (48)% | (1.15) | (3.49) | 303% |
| Transportation | (1.16) | (1.32) | 0.16 | (12)% | (1.15) | (0.17) | 15% |
| Hedging | - | 17.16 | (17.16) | (100)% | (9.30) | 26.46 | (285)% |
| Average realized oil price | $ 75.97 | $ 73.00 | $ 2.97 | 4% | $ 88.07 | $ (15.07) | (17)% |
| | | | | | | | |
| Average NYMEX gas price | $ 4.40 | $ 4.17 | $ 0.23 | 6% | $ 8.91 | $ (4.74) | (53)% |
| Basis differential and quality adjustments | 0.51 | 0.28 | 0.23 | 82% | 1.19 | (0.91) | (76)% |
| Hedging | 0.13 | 0.33 | (0.20) | (61)% | (0.11) | 0.44 | (400)% |
| Average realized gas price | $ 5.04 | $ 4.78 | $ 0.26 | 5% | $ 9.99 | $ (5.21) | (52)% |

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Revenues

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

| | Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Revenues for the year ended December 31, 2007 | $71,891 | $98,877 | $170,768 |
| Volume decrease | (8,183) | (52,091) | (60,274) |
| Price increase | 28,015 | 12,213 | 40,228 |
| Impact of hedges decrease | (8,760) | (650) | (9,410) |
| Net increase (decrease) in 2008 | 11,072 | (40,528) | (29,456) |
| 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 in 2009 | (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 in 2010 | (8,599) | (2,778) | (11,377) |
| Revenues for the year ended December 31, 2010 | $65,243 | $24,639 | $89,882 |

Total Revenue

Total oil and 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 from our legacy properties and damage to one of our Gulf of Mexico gas field production facilities. These declines were partially offset by new production from our Permian Basin and Haynesville Shale properties.

Total 2009 oil and gas revenues of $101.3 million decreased 28% or $40 million from $141.3 million in 2008 primarily due to lower oil and gas average realized sales prices. As reflected in the table above, hedge related revenues and a 3% increase in total production on an equivalent basis partially offset the decline in revenue for 2009 compared to 2008.

Oil Revenue

Crude 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.

Oil production during 2009 totaled 1.0 million barrels and generated $73.8 million in revenues compared to 0.9 million barrels and $83.0 million in revenues for the same period in 2008. Average oil prices realized in 2009 were $73.00 per barrel compared to $88.07 per barrel in 2008. See the Results of Operations table for a reconciliation of the realized oil prices to average NYMEX. The 7% increase in 2009 production was primarily due to the 2009 volumes associated with the BOEMRE royalty recoupment, described in Note 16, for the Medusa Field.

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Gas Revenue

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 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 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. 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 BOEMRE 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 legacy properties and production suspensions related to well recompletions and BOEMRE recompletion work approval such as at our Mobile Block 864 well. Offsetting these declines are increases from our Permian Basin properties discussed above, and production from our first Haynesville gas well, which was placed on production during September 2010.

Gas production during 2009 totaled 5.7 Bcf and generated $27.4 million in revenues compared to 5.8 Bcf and $58.3 million in revenues during the same period in 2008. Average gas prices realized for 2009 were $4.78 per Mcf compared to $9.99 per Mcf during the same period in 2008. The 2% decrease in 2009 production was primarily normal and expected declines from our legacy properties.

Operating Expenses

| | For the year ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Year Change | |
| | 2010 | Per Boe | 2009 | Per Boe | $ | % |
| Lease operating expenses | 17,712 | $10.58 | $18,447 | $9.37 | $(735) | (4)% |
| Depreciation, depletion and amortization | 31,805 | 19.00 | 33,443 | 16.99 | (1,638) | (5)% |
| General and administrative, net | 16,507 | 9.86 | 13,355 | 6.78 | 3,152 | 24% |
| Accretion expense | 2,446 | 1.46 | 3,149 | 1.60 | (703) | (22)% |
| Acquisition expense | 233 | 0.14 | 298 | 0.15 | (65) | (22)% |
| Total operating expenses | 68,703 | | $68,692 | | | |

| | For the year ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Year Change | |
| | 2009 | Per Boe | 2008 | Per Boe | $ | % |
| Lease operating expenses | 18,447 | $9.37 | $19,208 | $10.03 | $(761) | (4)% |
| Depreciation, depletion and amortization | 33,443 | 16.99 | 64,054 | 33.45 | (30,611) | (48)% |
| General and administrative, net | 13,355 | 6.78 | 9,565 | 4.99 | 3,790 | 40% |
| Accretion expense | 3,149 | 1.60 | 4,172 | 2.18 | (1,023) | (25)% |
| Acquisition expense | 298 | 0.15 | - | - | 298 | 100% |
| Derivative expense | - | - | 498 | 0.26 | (498) | (100)% |
| Impairment of oil and gas properties | - | - | 485,498 | 253.50 | (485,498) | (100)% |
| Total operating expenses | 68,692 | | $582,995 | | | |

Lease Operating Expenses

For the year ended December 31, 2010, lease operating expenses ("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, as previously discussed above in the oil revenue comparative analysis, 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.

Lease operating expenses for 2009 decreased by 4% to $18.4 million compared to $19.2 million for the same period in 2008. The decrease was primarily due to a lower number of producing wells in the Gulf of Mexico Shelf area. Four of our gas wells were shut-in during 2008 due to early water production and are plugged and abandoned or scheduled for plugging and abandonment. In addition, our High Island Block A-540 well was shut-in during the second quarter of 2008, due to a plugged flowline, which management determined uneconomic to repair. This well was plugged in the second half of 2009.

Depreciation, Depletion and Amortization

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.

Depreciation, depletion and amortization for 2009 and 2008 totaled $33.4 million and $64.1 million, respectively. The 48% decrease was due to a lower depletion rate resulting from the full-cost ceiling writedown, which was recorded in the fourth quarter of 2008 and the downward revision of plugging and abandonment cost for the Entrada field during 2009.

General and Administrative, net of amounts capitalized

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 the Company's Compensation Committee of the Board of Directors. 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 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.

General and administrative expenses for 2009, net of amounts capitalized, were $13.4 million compared to $9.6 million in 2008. The 43% increase was primarily due to the $2.2 million of nonrecurring expenses for staffing reductions and retirements and the result of overhead fees of approximately $2.6 million received during the second half of 2008 as operator of the Entrada Field, which was recorded as a reduction to general and administrative expenses in 2008.

Accretion Expense

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. Similarly, 2009 accretion expense of $3.1 million declined compared to 2008 accretion expense of $4.2 million, due to a lower average ARO liability in 2009 compared to the 2008 liability. For additional information regarding the company's oil and gas properties and the related ARO, see Notes 13 and 14 included to the Consolidated Financial Statements.

Impairment of Oil and Gas Properties

No impairments of oil and gas properties were recorded during either 2010 or 2009. During the fourth quarter of 2008, capitalized costs of oil and gas properties, net of accumulated amortization and deferred taxes relating to oil and gas properties, exceeded the sum of (1) the estimated future net revenues from proved reserves at current prices discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax effects. As a result, $485.5 million of excess costs was expensed as an impairment of oil and gas properties for the year ended December 31, 2008. For additional information, see Note 13 to the Consolidated Financial Statements.

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Other (Income) Expense

| | For the year ended December 31, | | | | | Year Change | |
|---|---|---|---|---|---|---|---|
| | 2010 | 2009 | $ Change | % Change | 2008 | $ (Dollars) | % (Percent) |
| Interest expense | $13,312 | $19,089 | $(5,777) | (30)% | $23,986 | $(4,897) | (20)% |
| Callon Entrada non-recourse credit facility interest expense (See Note 3) | - | 7,072 | (7,072) | (100)% | 2,719 | 4,353 | 160% |
| Loss on early extinguishment of debt | 339 | - | 339 | 100% | 11,871 | (11,871) | (100)% |
| 9.75% Senior Notes restructuring expenses | - | 1,024 | (1,024) | (100)% | - | 1,024 | 100% |
| Interest on BOEMRE royalty recoupment | (91) | (7,681) | 7,590 | (99)% | - | (7,681) | (100)% |
| Other (income) expense | (166) | 190 | (356) | (187)% | (1,379) | 1,569 | (114)% |
| Total other (income) expenses | $13,394 | $19,694 | | | $37,197 | | |
| | | | | | | | |
| Income tax benefit | (174) | - | (174) | 100% | $39,725 | $(39,725) | (100)% |
| Equity in earnings of Medusa Spar LLC | $427 | $660 | $(233) | (35)% | 262 | (262) | 152% |

Interest Expense

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 Old Notes, 92% of which were exchanged during 2009. Further, the remaining $16.1 million of outstanding Old 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.

Interest expense related to debt obligations decreased to $19.1 million in 2009 compared to $24.0 million in 2008. This 20% decrease was due to the retirement in April 2008 of the $200 million senior revolving credit facility associated with the Entrada acquisition. For additional information, see Note 6 to the Consolidated Financial Statement.

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, during 2010 we incurred no expense related to this non-recourse credit facility.

For the years ended December 31, 2009 and 2008, we incurred interest expense under the Callon Entrada credit agreement of $7.1 million and $2.7 million, respectively. The increase was due to a larger outstanding loan balance for the twelve-month period ended December 31, 2009 and an increase in the interest rate due to the notice of default received from CIECO on April 2, 2009. Principal and related interest was payable from the assets of Callon Entrada, primarily production from the Entrada Field with no recourse to the assets of Callon. Accordingly, due to the abandonment of the Entrada project, no cash payments for principal or interest have been made by Callon Entrada except with proceeds from our 50% share of the sale of surplus equipment.

Loss on 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 Old Notes not exchanged during the restructuring of the Old Notes, plus $0.18 million for the accelerated amortization of the Old Notes' remaining discount and debt issuance costs.

Due to the early extinguishment of the $200 million senior revolving credit facility on April 8, 2008, we incurred expenses of $11.9 million consisting of $6.3 million in cash pre-payment penalties plus a non-cash charge of $5.6 million related to the amortization expense associated with the deferred financing costs related to the senior revolving credit facility. For additional information, see Note 6 to the Consolidated Financial Statements.

9.75% Senior Notes Restructuring Expense

During the fourth quarter of 2009 and following the successful exchange of our Old Note for the 13% Senior Notes, 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 BOEMRE Royalty Recoupment

Following a court ruling against the BOEMRE resulting from several royalty payment-related court cases brought by another oil and gas company, during 2009 we filed for a $44.8 million royalty recoupment for royalty payments previously made on inception-to-date our production from Medusa field. Consequently, the Company also recorded a related $7.7 million interest receivable for the interest owed on the amounts paid. During the first quarter of 2010, the Company received both the recoupment principal and interest. In addition, the Company is no longer required to make any future royalty payments to the BOEMRE related to its Medusa production. For additional information, see Note 16 included to the Consolidated Financial Statements.

Income Tax Expense

For the years ended December 31, 2010 and 2009, income tax expense was negligible despite earning pre-tax income of approximate $7.8 million and $53.8 million, respectively. Income tax expense remained immaterial due to adjustments made to our deferred tax asset valuation. During 2010, we recorded a $0.2 million tax benefit related to recovery of alternative minimum taxes paid during prior years.

For 2009, income tax expense was zero compared to an income tax benefit of $39.7 million in 2008. The income tax benefit in 2008 was primarily the result of expensing the impairment of oil and gas properties in the amount of $485.5 million. We established a valuation allowance of $128.1 million as of December 31, 2008. We revised the valuation allowance for the twelve-month period ended December 31, 2009 as a result of current year ordinary income, the impact of which is included in our effective tax rate. For additional information, see Note 12 to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements

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

Summary of Significant Accounting Policies

Property and Equipment

The Company utilizes the full-cost method of accounting for its oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and 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 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 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 gas properties;

- payroll costs including the related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and 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 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 us 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

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 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 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 gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are based on a twelve-month average pricing assumption. Given the volatility of oil and gas prices, it is reasonably possible that the Company's estimates of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur in the future. See Notes 2 and 13 for additional information regarding the Company's oil and gas properties.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows

Estimates of quantities of proved oil and 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 gas production in the future. Oil and gas prices are volatile, but we are required to assume that they remain constant. In general, higher oil and gas prices will increase quantities of proved reserves and the present value of estimated future net cash flows from such reserves, while lower prices will decrease these amounts; and

- the costs to develop and produce the Company's reserves and the costs to dismantle its production facilities when reserves are depleted. These costs are likely to change over time, but the Company is required to assume that costs in effect at the end of the quarter will not change. Increases in costs will reduce estimated oil and 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 gas reserves for the Company's properties that have relatively short productive lives.

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

Sales of oil and 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

The Company is 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 gas price risk on a limited amount of its planned future production, the Company periodically uses derivative financial instruments. 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, all of which are accounted for as cash flow hedges, 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 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). For additional information regarding derivatives and their fair values, see Notes 7 and 8 to the Consolidated Financial Statements.

Subsequent Events.

For additional information regarding subsequent events, see Note 19 included in Part II, Item 8 of this filing.

Equity Offering and Announced Senior Notes Redemption

As previously discussed above in the Results of Operations and Liquidity discussions, during February 2011, the Company received $73.7 million in net proceeds through the public offering of 10.1 million shares of its common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. Immediately following the completion of the equity offering, the Company provided the public notice required by the terms of the Senior Notes to call $31.0 million of face value of the Notes. The Company expects to complete the redemption of these notes by March 19, 2011, which will result in a gain on the early extinguishment of debt of approximately $2.0 million. The gain represents the difference between the $35.0 million paid for $37.0

million carrying value of the Notes, which included the $31.0 million face value of the notes plus $6.0 million of accelerated deferred credit amortization, offset by the $4.0 million 13% call premium required by the terms of the call option.

Arbitration Results

Prior to abandonment of the Entrada project, the Company's joint interest owner in the Entrada Project failed to fund two loan requests totaling $40 million under the Callon Entrada credit agreement. These loan requests were to cover Callon Entrada's share of the costs incurred to develop the Entrada field up to the suspension of the project. Following its partner's failure to fund these requests, the amounts were subsequently funded by the Company to Callon Entrada, and were included as part of the Company's full-cost pool impairment adjustment recorded in the fourth quarter of 2008. The joint interest partner also failed to fund its working interest share of a settlement payment to terminate a drilling contract for the Entrada Project. The Company and its joint interest partner in the Entrada project arbitrated the matter during 2010. During February, 2011, the arbitration panel reviewing the Company's claims against the joint interest owner delivered its final decision in which it ruled that the company was not entitled to recover any damages. The Company determination that the arbitration ruling represented a recognizable subsequent event, and as such, recorded a charge as of December 31, 2010 to write off its $6.6 receivable related to certain joint interest billings not being recovered from a joint interest partner. Under the full cost method of accounting, these costs are capitalized to the Company's full cost pool.

Recent Accounting Standards

For a discussion of recently issued accounting standards, see Note 2 to the Consolidated Financial Statements.

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ITEM 7A. Quantitative and Qualitative Disclosures about Market Risks

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures.

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 2011, excluding production from 2011 exploratory drilling and the effects of the Company's hedging program, a 10% decline in the prices we receive for our crude oil and natural gas production would result in an approximate $10.6 million reduction of our revenues.

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 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 counter-party to the collar pays the difference to Callon, and if the price rises above the ceiling, Callon pays the difference to the counter-party.

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 gas prices while allowing realization of the full benefit from any increases in oil and gas prices. If the price falls below the floor, the counter-party pays the difference to the Callon.

During 2010, all of the Company's derivative positions were designated as hedges for accounting purposes, though the Company has the discretion not to designate its hedges as such. For additional information, see Note 7 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2010.

Interest Rate Risk

On December 31, 2010, 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, 2010 under its revolving credit facility, were the Company to fully draw its available $30 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 $0.3 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, 2010.

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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the 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.

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, 2010, 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, 2011, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 14, 2011

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

| | December, 31 2010 | December, 31 2009 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $17,436 | $3,635 |
| Accounts receivable | 10,728 | 20,798 |
| Accounts receivable - BOEMRE royalty recoupment | - | 51,534 |
| Fair market value of derivatives | - | 145 |
| Other current assets | 2,180 | 1,572 |
| Total current assets | 30,344 | 77,684 |
| | | |
| Oil and gas properties, full-cost accounting method: | | |
| Evaluated properties | 1,316,677 | 1,593,884 |
| Less accumulated depreciation, depletion and amortization | (1,155,915) | (1,488,718) |
| Net oil and gas properties | 160,762 | 105,166 |
| Unevaluated properties excluded from amortization | 8,106 | 25,442 |
| Total oil and gas properties | 168,868 | 130,608 |
| | | |
| Other property and equipment, net | 3,370 | 2,508 |
| Restricted investments | 4,044 | 4,065 |
| Investment in Medusa Spar LLC | 10,424 | 11,537 |
| Other assets, net | 1,276 | 1,589 |
| Total assets | $218,326 | $227,991 |
| | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT) | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $17,702 | $12,887 |
| Asset retirement obligations | 2,822 | 4,002 |
| Fair market value of derivatives | 937 | - |
| 9.75% Senior Notes, net of $0 and $232 discount, respectively | - | 15,820 |
| Subtotal | 21,461 | 32,709 |
| Callon Entrada non-recourse credit facility (See Note 3) | - | 84,847 |
| Total current liabilities | 21,461 | 117,556 |
| | | |
| 13% Senior Notes | | |
| Principal outstanding | 137,961 | 137,961 |
| Deferred credit, net of accumulated amortization of $3,964 and $294, respectively | 27,543 | 31,213 |
| Total 13% Senior Notes (See Note 6) | 165,504 | 169,174 |
| | | |
| Senior secured revolving credit facility | - | 10,000 |
| Asset retirement obligations | 13,103 | 10,648 |
| Other long-term liabilities | 2,448 | 1,467 |
| Total liabilities | 202,516 | 308,845 |
| | | |
| Stockholders' equity (deficit): | | |

| | | |
|---|---|---|
| Preferred Stock, $.01 par value, 2,500,000 shares authorized; | - | - |
| Common Stock, $.01 par value, 60,000,000 shares authorized; 28,984,125 and 28,742,926 shares outstanding at December 31, 2010 and December 31, 2009, respectively | 290 | 287 |
| Capital in excess of par value | 248,160 | 243,898 |
| Other comprehensive loss | (8,560) | (7,478) |
| Retained earnings (deficit) | (224,080) | (317,561) |
| Total stockholders' equity (deficit) | 15,810 | (80,854) |
| Total liabilities and stockholders' equity (deficit) | $218,326 | $227,991 |

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

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

| | For the year ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating revenues: | | | |
| Oil sales | $65,243 | $73,842 | $82,963 |
| Gas sales | 24,639 | 27,417 | 58,349 |
| BOEMRE royalty recoupment | - | 40,886 | - |
| Total operating revenues | 89,882 | 142,145 | 141,312 |
| Operating expenses: | | | |
| Lease operating expenses | 17,712 | 18,447 | 19,208 |
| Depreciation, depletion and amortization | 31,805 | 33,443 | 64,054 |
| General and administrative | 16,507 | 13,355 | 9,565 |
| Accretion expense | 2,446 | 3,149 | 4,172 |
| Acquisition expense | 233 | 298 | - |
| Derivative expense | - | - | 498 |
| Impairment of oil and gas properties | - | - | 485,498 |
| Total operating expenses | 68,703 | 68,692 | 582,995 |
| Income (loss) from operations | 21,179 | 73,453 | (441,683) |
| Other (income) expenses: | | | |
| Interest expense | 13,312 | 19,089 | 23,986 |
| Callon Entrada non-recourse credit facility interest expense (See Note 3) | - | 7,072 | 2,719 |
| Loss on early extinguishment of debt | 339 | - | 11,871 |
| 9.75% Senior Notes restructuring expenses | - | 1,024 | - |
| Interest on BOEMRE royalty recoupment | (91) | (7,681) | - |
| Other (income) expense | (166) | 190 | (1,379) |
| Total other expenses | 13,394 | 19,694 | 37,197 |
| Income (loss) before income taxes | 7,785 | 53,759 | (478,880) |
| Income tax benefit | (174) | - | (39,725) |
| Income (loss) before equity in earnings of Medusa Spar LLC | 7,959 | 53,759 | (439,155) |
| Equity in earnings of Medusa Spar LLC | 427 | 660 | 262 |
| Net income (loss) available to common shares | $8,386 | $54,419 | $(438,893) |
| Net income (loss) per common share: | | | |
| Basic | $0.29 | $2.47 | $(20.68) |
| Diluted | $0.28 | $2.45 | $(20.68) |
| Shares used in computing net income per common share: | | | |
| Basic | 28,817 | 22,072 | 21,222 |

| | | | |
|---|---|---|---|
| Diluted | 29,476 | 22,200 | 21,222 |

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) |
|---|---|---|---|---|---|---|
| Balances at December 31, 2007 | $- | $209 | $223,336 | $ (3,383) | $66,913 | $ 287,075 |
| | | | | | | |
| Comprehensive income (loss): | | | | | | |
| Net loss | - | - | - | - | (438,893) | |
| Other comprehensive income | - | - | - | 17,540 | - | |
| Total comprehensive loss | | | | | | (421,353) |
| Shares issued pursuant to employee benefit plans | - | 1 | (1,153) | - | - | (1,152) |
| Tax benefits related to share-based compensation plans | - | - | 2,050 | - | - | 2,050 |
| Restricted stock | - | 1 | 3,575 | - | - | 3,576 |
| Warrants | - | 5 | (5) | - | - | - |
| | | | | | | |
| Balances at December 31, 2008 | $- | $216 | $227,803 | $ 14,157 | $(371,980) | $ (129,804) |
| | | | | | | |
| Comprehensive income: | | | | | | |
| Net income | - | - | - | - | 54,419 | |
| Other comprehensive loss | - | - | - | (21,635) | - | |
| 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 |
| | | | | | | |
| Balances at December 31, 2009 | $- | $287 | $243,898 | $ (7,478) | $(317,561) | $ (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 |
| | | | | | | |
| Balances at December 31, 2010 | $- | $290 | $248,160 | $ (8,560 ) | $(224,080 ) | $ 15,810 |

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

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

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Cash flows from operating activities: | | | |
| Net income | $8,386 | $54,419 | $(438,893) |
| Adjustments to reconcile net income to | | | |
| cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 32,629 | 34,274 | 64,862 |
| Impairment of oil and gas properties | - | - | 485,498 |
| Accretion expense | 2,446 | 3,149 | 4,172 |
| Amortization of non-cash debt related items | 397 | 2,816 | 4,185 |
| Amortization of deferred credit | (3,670) | (294) | - |
| Equity in earnings of Medusa Spar LLC | | | |