Rosetta Resources Inc.
Form 10-K
February 26, 2010

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

FORM 10-K

x Annual Report Pursuant To Section 13 or 15(d) of The Securities Exchange Act of 1934

For The Fiscal Year Ended December 31, 2009

OR

o Transition Report Pursuant To Section 13 Or 15(d) of The Securities Exchange Act of 1934

Commission File Number: 000-51801

ROSETTA RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	43-2083519 (I.R.S. Employer Identification No.)
717 Texas, Suite 2800, Houston, TX (Address of principal executive offices)	77002 (Zip Code)

Registrant's telephone number, including area code: (713) 335-4000

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, $.001 Par Value (Title of Class)	The Nasdaq Stock Market LLC (Nasdaq Global Select Market) (Name of Exchange on which registered)

Securities Registered Pursuant to Section 12 (g) of the Act:
None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes o No x

Indicate by check mark whether the 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 o

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 o No o

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 the registrant's 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. o

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 the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer x
Non-Accelerated filer o	Smaller Reporting Company o
(Do not check if a 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 o No x

The aggregate market value of the voting and non-voting common equity held by Non-affiliates of the registrant as of June 30, 2009 was approximately $446.9 million based on the closing price of $8.76 per share on the Nasdaq Global Select Market.

The number of shares of the registrant’s Common Stock, $.001 par value per share outstanding as of February 24, 2010 was 52,589,439.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2010 annual meeting of stockholders to be filed with the Securities and Exchange Commission are incorporated by reference in answer to Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements regarding factors that we believe may affect our performance in the future. Such statements typically are identified by terms expressing our future expectations or projections of revenues, earnings, earnings per share, cash flow, market share, capital expenditures, effects of operating initiatives, gross profit margin, debt levels, interest costs, tax benefits and other financial items. All forward-looking statements are based on assumptions about future events and are therefore inherently uncertain, and actual results may differ materially from those expected or projected. Important factors that may cause our actual results to differ materially from expectations or projections include those described under the heading "Risk Factors" in Item 1A of this Form 10-K. Forward-looking statements speak only as of the date of this report, and we undertake no obligation to update or revise such statements to reflect new circumstances or unanticipated events as they occur.

For a glossary of oil and natural gas terms, see page 85.

Part I

Items 1 and 2. Business and Properties

General

We are an independent oil and gas company engaged in the exploration, development, acquisition and production of oil and gas properties. Our operations are concentrated in the core areas of the Sacramento Basin of California, the Rockies, and South Texas. In addition, we have non-core positions in the State Waters of Texas and the Gulf of Mexico. We are a Delaware corporation based in Houston, Texas. Our headquarters are located at 717 Texas, Suite 2800, Houston, Texas 77002, where we sublease two floors of office space from Calpine and lease a third floor. We also maintain a division office in Denver, Colorado, where we were assigned a lease by Calpine and now deal directly with the landlord. We also have field offices in Laredo, Texas, Rio Vista, California and Wray, Colorado. All office leases were negotiated at market prices applicable to their respective location.

Rosetta Resources Inc. (together with our consolidated subsidiaries, the "Company" or "Rosetta") was formed in June 2005 to acquire the domestic oil and natural gas business formerly owned by Calpine Corporation and its affiliates ("Calpine"). We have subsequently acquired numerous other oil and natural gas properties. We have grown our existing property base by developing and exploring our acreage, purchasing new undeveloped leases, and acquiring oil and gas producing properties and drilling prospects from third parties. We operate in one business segment. See Item 8. "Financial Statements and Supplementary Data, Note 15 - Operating Segments."

We sell a significant portion of our gas to Calpine pursuant to certain gas purchase and sales contracts, including the gas sales agreement for the dedicated California production which was amended and restated in connection with the parties' settlement agreement dated October 22, 2008. These original gas purchase and sales contracts and the amended and restated gas purchase and sales contract for the dedicated California production are discussed further under Part I. Items 1 and 2. "Business and Properties - Marketing and Customers."

Our Strategy

Our strategy is to increase stockholder value by delivering visible and sustainable growth from unconventional onshore domestic basins. This strategy represents a shift in our business model that is consistent with our goal to become a successful resource player with sufficient project inventory to drive growth. We recognize that there may be cycles, such as the current economic downturn, that could impact our ability to fully execute this strategy on a short-term basis. However, we believe our strategy is fundamentally sound and emphasizes (i) identifying and developing inventory in existing core properties, (ii) establishing and testing positions in new resource plays, (iii) efficiently exploring and exploiting our assets, (iv) pursuing selective acquisitions and divestitures, (v) applying technological expertise, (vi) focusing on cost control and (vii) maintaining financial flexibility. We seek to implement our strategy while working to protect stockholder interests by focusing on sound stewardship, managing our capital resources wisely, monitoring emerging trends, minimizing liabilities through governmental compliance and protecting the environment. Below is a discussion of the key elements of our strategy:

Identifying and Developing Inventory in Existing Core Properties. Project inventory is a key to our strategy and we believe our legacy assets have significant remaining inventory potential. We have designated the Sacramento Basin of California, the Rockies and South Texas as core areas and intend to expand our asset base in these areas through additional leasing and acquisitions, where applicable, in order to build inventory. As importantly, we intend to further develop the upside potential of these core properties by conducting thorough resource assessments of our existing assets, working over existing wells, drilling in-fill locations, drilling step-out wells to expand known field outlines, testing and implementing downspacing potential, recompleting and testing behind pipe pays, lowering field line pressures through compression and optimizing for additional reserve recovery. We believe that applying an "unconventional lens" to these assets will generate inventory to fuel future growth.

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Establishing and Testing Positions in New Resource Plays. We intend to extend our operational footprint into new core areas within North America that are characterized by a significant presence of resource potential that can be exploited utilizing our technological expertise. We strive to minimize the cost of entry into these plays by being disciplined in our leasehold acquisition activities and prudently paced during the testing phase.

Efficiently Exploring and Exploiting our Assets. We intend to generate growth in existing and new areas by applying our technological and operational expertise to our inventory of projects. We believe that this is a key to creating value from resource plays.

Pursuing Selective Acquisitions and Divestitures. We regularly evaluate possible acquisitions of producing properties, undeveloped acreage and drilling prospects in our existing core areas, as well as areas where we believe we can establish new core areas with resource potential. We focus on opportunities with identified inventory where we believe our reservoir management and operational expertise will enhance the value and performance of the acquired properties through repeatable drilling programs. Periodically, we also evaluate possible divestitures of non-core properties that we believe have limited future potential or that do not fit our risk profile. In 2009, we sold certain non-core assets for a total of approximately $20 million.

Applying Technological Expertise. We intend to maintain, further develop and apply the technological expertise that helped us achieve a net drilling success rate of 83% for the year ended December 31, 2009 and helped us maximize field recoveries. Our definition of drilling success is a well that is producing or capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. We use advanced geological and geophysical technologies, detailed petrophysical analyses, advanced reservoir engineering and sophisticated drilling, completion and stimulation techniques to grow our reserves, production and project inventory.

Focusing on Cost Control. We manage all elements of our cost structure including drilling and operating costs as well as overhead costs. We strive to minimize our drilling and operating costs by concentrating our activities within existing and new resource play areas where we can achieve efficiencies through economies of scale.

Maintaining Financial Flexibility. As of December 31, 2009, we had drawn $190.0 million and had $160.0 million available for borrowing under our revolving line of credit. Additionally, we expect internally generated cash flow to provide additional financial flexibility. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our oil and natural gas production. As part of this strategy, we entered into natural gas fixed-price swaps for a portion of our expected production through 2011. As of December 31, 2009, 13% and 13% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2010, and 5% and 23% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2011. The swaps to settle in 2010 have an average price of $7.46 per MMBtu and the collars have floor and ceiling prices of $5.75 per MMBtu and $7.40 per MMBtu, respectively. The swaps to settle in 2011 have an average price of $5.72 per MMBtu and the collars have floor and ceiling prices of $5.80 per MMBtu and $7.58 per MMBtu, respectively. In January 2010, we entered into additional costless collar transactions to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2012. The costless collars have a floor price of $5.75 per MMBtu and a ceiling price of $6.50 per MMBtu through 2011 and $7.15 per MMBtu in 2012. In February 2010, we entered into natural gas fixed-price swaps to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2011 at an average price of $5.91 per MMBtu. We also entered into a series of interest rate swap agreements during 2009 to hedge the change in variable interest rates associated with our debt under our credit facility through December 2010.

Our Strengths

Our business strategy and our goal to become a successful resource player are not proprietary. However, we believe we possess several strengths that could differentiate our performance over time. We believe our key strengths are as follows:

High Quality Asset Base. We own what we believe is a unique asset base in key onshore hydrocarbon basins. Approximately 85% of our reserves are natural gas and, except for some minor non-core properties, most of our assets are located in our core areas of the Sacramento Basin of California, the Rockies, and South Texas. Thus, we are both relatively concentrated, yet geographically diverse. Our concentration allows us to achieve scale, while the geographic diversity exposes us to different commodity pricing locations, including some premium markets. In addition, a significant portion of our legacy asset base requires relatively low levels of maintenance capital, which enhances our flexibility to allocate capital. In combination with our new resource plays, our asset base is capable of yielding growth from a large and growing inventory of projects. We also believe our current asset base provides a strong platform for additional acquisitions.

Resource Assessment Capability and Inventory Generation. We have established multi-disciplinary teams that are skilled at conducting comprehensive resource assessments on a field and regional basis. This work helps us indentify and catalog an inventory of low to moderate risk opportunities that provide us with multiple years of drilling projects. We expect to continue to add to our diversified portfolio of non-proved resource inventory over time from both our legacy properties, as well as from our emerging resource plays.

Operational Control. We operate approximately 87% of our estimated proved reserves, which allows us to more effectively manage expenses and control the timing of capital spending on our exploration and development activities. In addition, we have a very high working interest in most of our properties and a high percentage of acreage that is held by production. These factors also give us greater flexibility over our activities.

Experienced Management Team. Our executive management team has an average of 30 years of experience in the energy industry with specific experience in the areas where our core properties are located. In November 2007, Randy L. Limbacher became our President and Chief Executive Officer (“CEO”). In February 2010, Mr. Limbacher became our Chairman of the Board. Mr. Limbacher has more than 29 years of experience in the energy industry, most recently serving as President, Exploration and Production - Americas for ConocoPhillips. Since coming to Rosetta, Mr. Limbacher has continued to hire personnel with technical and commercial experience in unconventional resource plays.

Proven Technical and Land Personnel with Access to Technological Resources. Our technical staff includes 57 geologists, geophysicists, landmen, engineers and technicians with an average of over 14 years of relevant technical experience. Our staff has experience in analyzing complex structural and stratigraphic plays using 3-D geophysical expertise, producing and optimizing low pressure natural gas reservoirs, detecting low contrast, low permeability pay opportunities, drilling, completing and fracing of deep tight natural gas reservoirs, operating in complex basins and managing coalbed methane operations. These core competencies helped us to achieve a net drilling success rate of 83% for the year ended December 31, 2009 and helped maximize recovery from our reservoirs.

Our Operating Areas

We own core producing and non-producing oil and natural gas properties in proven or prospective basins that are primarily located in California, the Rockies, and South Texas. We also have non-core positions in the State Waters of Texas and the Gulf of Mexico. For the year ended December 31, 2009, we drilled 43 gross and 36 net wells, with a net success rate of 83%. The following is a summary of our major operating areas.

California

Historically, the Sacramento Basin is one of California’s most prolific gas producing areas, containing a majority of the state’s largest gas fields. It is located near the Northern California natural gas markets and has an established natural gas gathering and pipeline infrastructure. We are one of the largest producers and leaseholders in the basin.

As of December 31, 2009, we owned approximately 60,000 net acres in the Rio Vista Field and other fields in the Sacramento Basin areas. We believe our acreage in the basin holds significant low-risk, low-cost reserves, and numerous workover and recompletion opportunities. Additional reserve potential exists in gathering system optimization projects, fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

For the year ended December 31, 2009, our average net daily production from the Rio Vista Field and surrounding fields in the Sacramento Basin was 42.4 MMcfe/d. In 2009, we drilled one gross well which was successful.

Rio Vista Field. The Rio Vista Gas Unit and a significant portion of the deep rights below the Rio Vista Gas Unit, which together constitute the greater Rio Vista Field, is the largest onshore natural gas field in California and one of the 15 largest natural gas fields in the United States. The field has produced a cumulative 3.7 Tcfe of natural gas reserves to date since its discovery in 1936. We currently produce from or have behind-pipe reserves in multiple zones at depths ranging from 2,000 feet to 11,000 feet in the field. The Rio Vista Field is a faulted, downthrown rollover anticline, elongated to the northwest. The current productive area is approximately ten miles long and nine miles wide. We completed a successful low cost, by-passed pay recompletion program during 2009. Our 2009 recompletion program consisted of 40 projects with a total combined capital cost of $2.1 million.

As of December 31, 2009, there was one workover rig currently working on our wells in the Rio Vista area. We plan to conduct approximately 20 workovers, recompletions or reactivation operations on field wells during

2010. Moreover, a majority of our time and effort in 2010 will be devoted to resource assessments within the Rio Vista Gas Field. The resource assessments are expected to generate future drilling and recompletion inventory for 2011 and beyond.

Rockies

As of December 31, 2009, we owned approximately 160,000 net acres in the Rockies and had approximately 230,000 net acres under an exploration option in the Alberta Basin of Montana. Our production is concentrated in three basins: the DJ Basin, San Juan Basin and Greater Green River Basin. Our average net daily production for the year ended December 31, 2009 was 19.0 MMcfe/d. In 2009, we drilled five gross wells, all of which were successful.

DJ Basin, Colorado. As of December 31, 2009, we had a majority working interest in approximately 94,000 net acres with 154 square miles of 3-D seismic data. In 2009, due to low commodity prices, we chose to not drill and focused our efforts on resource assessment. For the year ended December 31, 2009, our average net daily production from the DJ Basin was 7.9 MMcfe/d. We commenced a 105-well drilling program in the first quarter of 2010 and expect to be completed by mid-year. This program is matched with favorable hedges in the Rockies that will improve project returns.

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San Juan Basin, New Mexico. The San Juan Basin is the second most prolific gas basin in North America, with significant contribution coming from the Fruitland Coal Bed Methane ("CBM") trend. There is CBM production from depths of 1,600 feet surrounding our leasehold. As of December 31, 2009, we had a 100% working interest in approximately 16,000 net acres. In 2009, we drilled 3 CBM wells, all of which were successful. For the year ended December 31, 2009, our average net daily production from the San Juan Basin was 5.0 MMcfe/d.

Pinedale, Wyoming. On December 11, 2008, we purchased a 90% working interest in 1,280 acres of the Pinedale field from Pinedale Energy LLC, a subsidiary of Constellation Energy Group, Inc. We purchased 28 productive natural gas wells and one salt water disposal well. On February 4, 2009, we purchased the remaining 10% working interest in the 1,280 acres in the Pinedale field from Nielsen & Associates, Inc. and obtained operatorship of the properties. Detailed resource assessment work commenced in the fourth quarter of 2009, which led to the implementation of three recompletions before year end. As assessment work continues in 2010, it is anticipated that new drilling and recompletion inventory will be identified. For the year ended December 31, 2009, our average net daily production from Pinedale was 6.0 MMcfe/d.

Alberta Basin, Montana. The Alberta Basin play is a westward analog of the industry's Bakken and Three Forks plays of the Williston Basin of Montana and North Dakota. On December 24, 2008, Rosetta received approval from the Bureau of Indian Affairs to option approximately 200,000 net acres located on the Blackfeet Indian Reservation in Western Montana. In 2009, we initiated the technical assessment of our acreage position by drilling two test wells, of which one was vertical and one was horizontal. We also continued land acquisition and consolidation efforts through fee and allottee leasing. As of year-end, our acreage position increased to approximately 240,000 net acres, including approximately 230,000 net acres under exploration option agreements.

South Texas

As of December 31, 2009, we owned approximately 170,000 net acres in South Texas. Our production in South Texas comes from the Lobo, Olmos, and Perdido sand trends and the Eagle Ford Shale trend and averaged 55.7 MMcfe/d for the year ended December 31, 2009. In 2009, we drilled 31 gross wells, of which 25 were successful. Additionally, we have significantly expanded our acreage holdings in the rapidly developing Eagle Ford Shale trend, and we maintain a significant position in the emerging Dinn Sand trend.

Lobo Trend. We are a significant producer in the South Texas Lobo Trend, with 470 square miles of 3-D seismic and 255 operated producing wells. Our working interests range from 50% to 100%, but most of our acreage is 100% owned and operated. In 2009, we shot a new proprietary 3-D seismic survey covering 112 square miles of our Lobo acreage. The data has been processed and is being evaluated to identify additional drilling locations. For the year ended December 31, 2009, our average net daily production from the Lobo trend was 44.1 MMcfe/d. In 2009, we drilled 27 gross wells, of which 21 were successful.

Discovered in 1973, the Lobo trend of South Texas is a complex, highly faulted sand that has produced over 8 Tcf of natural gas. The Lobo trend produces from tight sands with low permeabilities and high pressures at depths from 7,500 to 10,000 feet.

Eagle Ford Shale Trend. The Eagle Ford Shale trend has emerged as a focus area for Rosetta in South Texas. In 2009, we continued to acquire additional sizable acreage tracts with potential in this evolving shale gas play. Since 2008, we have accumulated approximately 53,000 net acres in the Eagle Ford Shale trend. Most of this acreage also has potential in the Austin Chalk and Edwards formations, as well as the newly emerging Pearsall Shale gas trend. In 2009, we drilled four gross wells to gather and evaluate the shale with core and log data. We then took two wells horizontal, completing both wells, each having approximately 4,000 foot laterals, with 10-stage hydraulic fracture treatments. For the quarter ended December 31, 2009, our average net daily production was 4.3 MMcfe/d.

Olmos Trend. On December 23, 2008, we closed on the acquisition of a 70% non-operated working interest in 231 gross producing Olmos wells in the Olmos trend of South Texas. Production from these wells averaged 3.8 MMcfe/d for the year ended December 31, 2009.

Perdido Sand Trend. We own a 50% non-operated working interest in the South Texas Perdido Sand trend. The Perdido Sands are comprised of tight natural gas sands and are in isolated fault blocks that are stratigraphically trapped below the Upper Wilcox structures at approximately 8,000 to 9,500 feet. We plan to continue to coordinate with the operator to improve horizontal and vertical drilling techniques to lower cost and increase performance. For the year ended December 31, 2009, our average net daily production was 6.5 MMcfe/d from 37 producing wells (24 horizontal and 13 vertical).

Dinn Sand Trend. In 2008, we acquired a significant acreage position with approximately 100% operated working interest adjacent to our existing Perdido development trend. This leasehold acquisition has potential in the intermediate depth Dinn Sand trend. The Dinn Sand has been sparsely developed with vertical wells, and has potential for additional horizontal and vertical well development over most of the leasehold. Additionally, much of the leasehold has potential for extending the Perdido Sand trend horizontal development from our adjacent non-operated 50% working interest acreage to this operated 100% working interest leasehold.

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Other Onshore

In the Other Onshore region, we currently have approximately 12,000 net acres under lease with an average non-operated working interest of 47%. Some of these properties are potential divestiture candidates in the future.

Texas State Waters

We own a 50% operated working interest through a joint venture in Sabine Lake, within Texas State Waters of Jefferson County and Louisiana State Waters of Cameron Parish, and additional non-operated properties in Texas State Waters near Nueces Bay. During 2009, we drilled three gross wells which were successful. Net production averaged 5.4 MMcfe/d during 2009. As of December 31, 2009, we held interests in approximately 4,000 net acres with 72 square miles of 3-D seismic data. These properties are considered to be non-core and are likely divestiture candidates.

Gulf of Mexico

Federal Waters. We own working interests in 12 offshore blocks ranging from 20% to 100% working interest with approximately 28,000 net acres. For the year ended December 31, 2009, our average net daily production from these blocks was 6.4 MMcfe/d. These properties are considered to be non-core and are likely divestiture candidates.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens on at least 80% of our proved reserves in accordance with our credit facilities. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we generally have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Crude Oil and Natural Gas Operations

Production by Operating Area

The following table presents certain information with respect to our production data for the period presented:

	For the Year Ended December 31, 2009			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe)
California	15.3	-	28.3	15.5
Rockies	6.8	-	19.8	6.9
South Texas	16.3	548.4	117.0	20.3
Other Onshore	2.8	33.8	94.0	3.6
Texas State Waters	1.5	21.1	62.3	2.0
Gulf of Mexico	1.8	16.8	72.5	2.3

Total	44.5	620.1	393.9	50.6

For additional information regarding our oil and gas production, production prices and production costs see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Expenses."

Proved Reserves

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Therefore, the reserve information in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

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As of December 31, 2009, we had an estimated 351.1 Bcfe of proved oil and natural gas reserves, including 296.8 Bcf of natural gas, 3,825 MBbls of oil and condensate and 5,221 MBbls of NGLs, of which 75% was proved developed. As of December 31, 2009 and based on the 2009 twelve-month first day of the month historical average referenced prices as adjusted for basis and quality differentials, our reserves had an estimated standardized measure of discounted future net cash flows of $465 million. In December 2008, the Securities and Exchange Commission ("SEC") issued its final rule, Modernization of Oil and Gas Reporting (Release No. 33-8995), which is effective for reporting 2009 reserve information. The primary impacts of the SEC's final rule on our reserve estimates include:

- the use of the twelve-month first day of the month historical average prices adjusted for basis and quality differentials for West Texas Intermediate oil of $57.65 per Bbl and Henry Hub natural gas of $3.87 per MMBtu compared to the use of year-end prices adjusted for basis and quality differentials for West Texas Intermediate oil of $76.00 per Bbl and Henry Hub natural gas of $5.79 per MMBtu at December 31, 2009 as previously required under SEC guidelines;

- the requirement that all proved undeveloped locations be developed within five years. As of December 31, 2009, we did not have any proved undeveloped locations to be developed beyond five years and we have the intent to develop all of our proved undeveloped locations within this five year timeframe; and

- the inclusion of proved undeveloped locations beyond one-offset is allowed if there is reasonable certainty of economic producibility. A few of our undeveloped locations are beyond one-offset and current production data, logs, microseismic, and geologic data supports reasonable certainty of economic producibility.

Under the SEC's final rule, prior period reserves were not restated.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2009:

	Estimated Proved Reserves at December 31, 2009 (1)(2)									
	Developed				Undeveloped					
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe)	Total (Bcfe)	Percent of Total Reserves
California	74.88	-	0.05	75.17	14.55	-	0.01	14.60	89.8	26 %
Rockies	64.80	-	0.25	66.27	3.86	-	-	3.86	70.1	20 %
South Texas	69.72	2.06	0.52	85.17	40.21	2.84	1.47	66.07	151.3	43 %
Other Onshore	13.63	0.00	0.52	16.75	-	-	-	-	16.7	5 %
Texas State Waters	4.10	0.24	0.27	7.16	-	-	-	-	7.2	2 %
Gulf of Mexico	9.48	0.05	0.72	14.10	1.54	0.03	0.02	1.89	16.0	4 %
Total	236.61	2.35	2.33	264.62	60.16	2.87	1.50	86.42	351.1	100 %

(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the SEC guidelines and audited by Netherland Sewell & Associates, Inc. (hereafter "NSAI"), independent petroleum engineers. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates" and Item 8. "Financial Statements and Supplementary Data - Supplemental Oil and Gas Disclosures." NSAI's report is attached as Exhibit 99.1 to this Form 10-K.

(2) The reserve volumes and values were determined under the method prescribed by the SEC, which for 2009 requires the use of an average price, calculated as the twelve-month first day of the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. For years prior to 2009, the SEC rules required the use of year-end prices.

All of our proved undeveloped reserves are scheduled for development within five years and at December 31, 2009, we did not have any proved undeveloped reserves greater than five years.

As of December 31, 2009, we had proved undeveloped reserves of 86.4 Bcfe, an increase of 15.6 Bcfe relative to December 31, 2008. Significant additions to proved undeveloped reserves resulted primarily from additional proved undeveloped locations in our Eagle Ford Shale acreage.

In accordance with SEC guidelines, the reserve engineers' estimates of future net revenues from our properties, and the present value of the properties, are made using the twelve-month first day of the month historical average oil and gas prices for the December 31, 2009 reserves and oil and gas sales prices in effect as of the end of the period of such estimates for prior periods, and are held constant throughout the life of the properties, except where the guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Historically, the prices for oil and gas have been volatile and are likely to continue to be volatile in the future.

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The table below sets forth our proved reserves calculated according to prior SEC guidelines using the year-end oil and natural gas prices adjusted for basis and quality differentials rather than the twelve-month first day of the month historical average prices adjusted for basis and quality differentials:

	Proved Reserves			
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe)
Price Scenario 1 (1)	355.7	5.6	3.7	411.6

(1) Price Scenario 1 assumes a West Texas Intermediate oil price adjusted for basis and quality differentials of $76.00 per Bbl and a Henry Hub natural gas price adjusted for basis and quality differentials of $5.79 per MMBtu at December 31, 2009.

Internal Control

The preparation of our reserve estimates are completed in accordance with our prescribed internal control procedures, which include verification of input data into a reserve forecasting and economic evaluation software, as well as management review. The Company's primary reserves estimator is the Company's Chief Engineer and Operations General Manager who has twenty-two years of experience in the petroleum industry with 18 years of experience in the evaluation of reserves and income attributable to oil and gas properties. She holds a Bachelor of Science in Petroleum Engineering, a Bachelor of Science in Geosciences and a Master of Business Administration from the University of Tulsa. She also holds a Master of Science in Petroleum Engineering from the University of Houston. She obtained a Doctor of Jurisprudence from South Texas College of Law and is a member of Phi Delta Phi honorary law society and the Society of Petroleum Engineers.

Our corporate reservoir engineering department reports to our Chief Engineer and Operations General Manager who maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to independent third party engineers for the annual audit of our year-end reserves. The management of our corporate reservoir engineering group, including the Chief Engineer, consists of two degreed petroleum engineers, with an average of 26 years of industry experience in reservoir engineering/management.

Qualifications of Third Party Engineers

The technical personnel responsible for preparing the reserve estimates at NSAI meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; it does not own an interest in our properties and is not employed on a contingent fee basis. NSAI's President and Chief Operating Officer is a licensed professional engineer with more than 30 years of experience and the geoscientist charged with the audit is a licensed professional with 25 years of experience.

2009 Capital Expenditures

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Capital Expenditures by Operating Area:			
California	$ 7,453	$ 42,429	$ 58,493
Rockies	17,227	25,015	23,904
South Texas	59,547	94,567	105,301
Other Onshore	2,974	12,927	29,796
Texas State Waters	4,545	8,541	27,000
Gulf of Mexico (1)	(2,788)	422	28,523
Leasehold	22,066	17,883	8,838
Acquisitions	3,624	115,074	38,656
Delay rentals	1,683	1,451	1,409
Geological and geophysical/seismic	8,558	4,571	4,422
Total capital expenditures (2)	$ 124,889	$ 322,880	$ 326,342

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(1) During the first quarter of 2009, a capital expenditure accrual for approximately $3.6 million was removed from capitalized costs. The accrued capital expenditure related to a property for which we had a non-operating interest. The well was drilled and operated by a third party prior to 2009. During the latter part of 2008, the operator sold their interest to a different third party and it was determined that there were to be no future capital obligations to the original operator. As such, the accrued capital expenditure was removed. Actual capital expenditures in the Gulf of Mexico during 2009 totaled approximately $0.8 million and were primarily related to drilling and completion costs and plug and abandonment costs.

(2) Capital expenditures for the year ended December 31, 2009 exclude capitalized internal costs directly identified with acquisition, exploration and development activities of $4.8 million, capitalized interest of $1.2 million and corporate other capital costs of $4.1 million. Capital expenditures for the year ended December 31, 2008 exclude capitalized internal costs directly identified with acquisition, exploration and development activities of $7.1 million, capitalized interest of $1.4 million and corporate other capital costs of $3.0 million. Capital expenditures for the year ended December 31, 2007 exclude capitalized internal costs directly identified with acquisition, exploration and development activities of $5.5 million, capitalized interest of $2.4 million and corporate other capital costs of $1.8 million. Corporate other capital costs consist of costs related to IT software/hardware, office furniture and fixtures and license transfer fees.

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2009. "Gross" represents the total number of acres or wells in which we own a working interest. "Net" represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing oil or natural gas.

	Undeveloped Acres		Developed Acres		Productive Wells (1)			
					Gross		Net	
	Gross	Net	Gross	Net	Natural Gas	Oil	Natural Gas	Oil
California	23,712	16,178	53,671	44,188	158	-	147	-
Rockies (2)	148,714	131,200	36,016	28,527	264	2	232	1
South Texas	113,315	99,902	103,229	69,546	531	2	411	2
Other Onshore	9,379	3,260	29,259	9,034	236	15	30	6
Texas State Waters	4,913	2,456	4,800	1,302	1	-	1	-
Gulf of Mexico	7,500	5,000	35,752	22,513	2	1	1	1
Total	307,533	257,996	262,727	175,110	1,192	20	822	10

(1) Offshore productive wells are based on intervals rather than well bores.
(2) Excludes 230,000 net undeveloped acres under exploration option in the Alberta Basin of Montana.

Of our productive wells listed above, there were 13 and 14 multiple completions in Texas and California, respectively.

The following table shows our interest in undeveloped acreage as of December 31, 2009 that is subject to expiration in 2010, 2011, 2012 and thereafter:

2010		2011		2012		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net

127,466	111,294	87,863	76,050	47,812	40,088	44,392	30,564

Drilling Activity

The following table sets forth the number of gross exploratory and development wells we drilled or in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells completed at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production.

	Gross Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2009	7.0	-	7.0	30.0	6.0	36.0
2008	3.0	1.0	4.0	160.0	20.0	180.0
2007	11.0	7.0	18.0	149.0	28.0	177.0

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The following table sets forth, for each of the last three fiscal years, the number of net exploratory and net development wells drilled by us based on our proportionate working interest in such wells.

	Net Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2009	6.1	-	6.1	23.4	6.0	29.4
2008	1.9	1.0	2.9	132.7	15.9	148.6
2007	7.5	5.1	12.6	130.2	26.5	156.7

As of December 31, 2009, we had one well in process. This well is located in the Alberta Basin and we own a 100% working interest in this well.

Marketing and Customers

We have entered into a natural gas purchase and sales contract with Calpine Energy Services ("CES") for the dedicated California production, which runs through December 2019. Under the terms of this agreement, we are obligated to sell all our existing and future production from our California leases in production as of May 1, 2005 based on market prices. For the month of December 2009, this dedicated California production comprised approximately 33% of our overall daily equivalent production.

Under the terms of the purchase and sales contract with CES, cash payment for all natural gas volumes that are contractually sold to CES on the previous day are deposited into our bank account. If the funds are not deposited one business day in arrears in accordance with our contracts, we are not obligated to continue to sell our production to CES and these sales may cease immediately. We would then be in a position to market this natural gas production to other parties. CES has 60 days to pay amounts owed to us, at which time, provided CES has fully cured such payment default, we are obligated under the contract to resume natural gas sales to CES.

We may market our remaining natural gas production in California to parties other than CES. All of our other production (other than our dedicated California production being sold to CES, as described above) is sold to various purchasers, including CES, at market rates. We market all of our oil and gas production and have expanded our internal capabilities in this regard, both by hiring experienced personnel and implementing our own licensed systems.

Major Customers

For the year ended December 31, 2009, we had one major customer, CES, which accounted for approximately 57% of our consolidated annual revenue.

Competition

The oil and natural gas industry is highly competitive, and we compete with a substantial number of other companies that have greater resources than we do. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resulting products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, and obtaining purchasers and transporters of the oil and natural gas we produce. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the federal, state and local government. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such legislation and regulations may, however, substantially increase the costs of exploring for, developing, producing or marketing natural gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

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Government Regulation

The oil and gas industry is subject to extensive laws that are subject to change. These laws have a significant impact on oil and gas exploration, production and marketing activities, and increase the cost of doing business, and consequently, affect profitability. Some of the legislation and regulation affecting the oil and gas industry carry significant penalties for failure to comply. While there can be no assurance that we will not incur fines or penalties, we believe we are currently in material compliance with the applicable federal, state and local laws. Because enactment of new laws affecting the oil and gas business is common and because existing laws are often amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil and gas company operating in the United States. The following are significant types of legislation affecting our business.

Exploration and Production Regulation

Oil and natural gas production is regulated under a wide range of federal, state and local statutes, rules, orders and regulations, including laws related to location of wells, drilling and casing of wells, well production limitations; spill prevention plans; surface use and restoration; platform, facility and equipment removal; the calculation and disbursement of royalties; the plugging and abandonment of wells; bonding; permits for drilling operations; and production, severance and ad valorem taxes. Oil and gas companies can encounter delays in drilling from the permitting process and requirements. Our operations are subject to regulations governing operation restrictions and conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, and prevention of flaring or venting of natural gas. The conservation laws have the effect of limiting the amount of oil and gas we can produce from our wells and limit the number of wells or the locations at which we can drill.

Environmental Regulation

General. Our operations are subject to extensive environmental, health and safety regulation by federal, state and local agencies. These requirements govern the handling, generation, storage and management of hazardous substances, including how these substances are released or discharged into the air, water, surface and subsurface. These laws and regulations often require permits and approvals from various agencies before we can commence or modify our operations or facilities, and on occasion (especially on federally-managed land) require the preparation of an environmental impact assessment or study (which can result in the imposition of various conditions and mitigation measures) prior to or in connection with obtaining such permits. In connection with releases of hydrocarbons or hazardous substances into the environment, we may be responsible for the costs of remediation even if we did not cause the release or were not otherwise at fault, under applicable laws. These costs can be substantial and we evaluate them regularly as part of our environmental and asset retirement programs. Failure to comply with applicable laws, permits or regulations can result in project or operational delays, civil or in some cases criminal fines and penalties and remedial obligations.

Sacramento and San Joaquin Rivers Delta. In November 2009, the California State legislature enacted and the governor signed a package of four bills, as well as an $11.14 billion bond measure to be voted on by the California voters in the November 2010 election. These bills promise to restore and maintain the delta resulting from the confluence of the Sacramento and San Joaquin rivers, while simultaneously sending needed water to the farmers in the western San Joaquin Valley and to urban and farming water users to the south. The Company currently produces about one third of its natural gas in this delta. We are involved in monitoring and providing comments to the anticipated plans, rules and regulations to be proposed by the State committees responsible for implementing this legislation. To the extent that the State elects to proceed with a peripheral canal, certain of the proposed options for the route of such a canal have the potential to impact some of our land and access rights in our Rio Vista Gas Field. In addition, proposed habitat restoration goals under the regulatory programs may be significant, and may include reduced or discontinued maintenance of certain existing levees to allow marshlands to return to their natural state. As a result, the implementation of this legislation and associated regulatory programs (and any potential peripheral canal) may increase significantly the Company's costs to maintain certain levees, and may affect our operations in the Rio Vista Gas Field.

Climate Change. Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for some of our produced materials. The United States Congress is currently considering legislation on climate change. In June 2009, the U.S. House of Representatives passed a comprehensive clean energy and climate bill (H.R. 2454, also known as "Waxman-Markey"). In the Senate, the Boxer-Kerry climate bill has been reported out of the Senate Environment and Public Works Committee. These bills have a variety of provisions and differences, but in substance they both propose a "cap and trade" approach to greenhouse gas regulation. Under such an approach, companies would be required to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances declines, the cost would presumably increase. In addition to the prospect of federal legislation, several states have adopted or are in the process of adopting greenhouse gas reporting or cap-and-trade programs. Therefore, while the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), we would expect our operating costs to increase as we buy additional allowances or embark on emission reduction programs.

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Even without further federal legislation, the United States Environmental Protection Agency (EPA) may act to regulate greenhouse gas emissions. In April 2007, the United States Supreme Court concluded that greenhouse gas emissions from automobiles were "air pollutants" within the meaning of the applicable provisions of the federal Clean Air Act. Relying in part on that precedent, in December 2009, the EPA released an Endangerment and Cause or Contribute Findings for Greenhouse Gases, which became effective in January 2010. This regulatory finding sets the foundation for future EPA greenhouse gas regulation under the Clean Air Act. The EPA also promulgated a new greenhouse gas reporting rule, which became effective in December 2009, and which requires facilities that emit more than 25,000 tons per year of carbon dioxide-equivalent emissions to prepare and file certain emission reports. The portion of the rule pertaining to fugitive and vented methane emissions from the oil and gas sector has not yet been incorporated into the final rule and remains proposed. If this portion of the proposed rule is ultimately promulgated, some of our facilities may be subject to the reporting requirements. Finally, in September 2009, the EPA proposed a new regulation, subject to public comment and not yet effective, which would impose additional permitting requirements on certain stationary sources. Depending on the final outcome of this rulemaking, some of our facilities may be subject to additional operating and other permit requirements. As a result of these regulatory initiatives, our operating costs may increase in compliance with these programs, although we are not situated differently in this respect from our competitors in the industry.

Hydraulic Fracturing. Congress is also considering legislation that would repeal the current exemption in the Safe Drinking Water Act's underground injection control program for hydraulic fracturing. We and our competitors use hydraulic fracturing in our shale gas operations. If this legislation is passed, it would impose additional requirements on our hydraulic fracturing operations, we would face additional requirements, including permitting requirements, financial assurances, public disclosure obligations, monitoring and reporting requirements. Such a result could increase our operating costs. The disclosure requirements also could increase the possibility of third-party or government legal challenges to hydraulic fracturing. Even without such legislation, hydraulic fracturing has come under increased regulatory scrutiny in certain locations, such as New York, although our operations have not yet been affected.

Wyoming Air Permit. On February 12, 2010, we received a Notice of Violation ("Notice") from the Wyoming Department of Environmental Quality ("Wyoming DEQ") regarding a multiple wellsite facility for wet gas/condensate production and six associated wells located in Sublette County, Wyoming (collectively, the "Wellsite"). The Notice alleges that we did not obtain a construction permit prior to constructing the Wellsite, and that we operated the Wellsite in violation of applicable regulations by allegedly having failed to control air emissions from six associated wells. The Notice threatens referral of this matter to the Wyoming Attorney General for "appropriate penalties," which could include civil penalties or injunctive relief. We have responded to the Notice, are in the process of implementing corrective action and have agreed with the Wyoming DEQ to discuss possible settlement of this matter. If we do not reach a settlement, we will contest any associated litigation. No civil penalties have been imposed nor has the Wyoming DEQ yet requested a specific civil penalty amount, although the maximum daily penalty for such violations is $10,000 per violation per day. Given the preliminary stage of this matter and the inherent uncertainty of enforcement actions of this nature, the Company is presently unable to predict the ultimate outcome of this enforcement action.

Insurance Matters

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is unavailable or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows. We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, not to carry loss of production or business interruption insurance for our operations. We carry limited property insurance for loss or damage caused by earthquakes and our energy package insurance, including property insurance, is limited to $4 million in the aggregate for any single named windstorm with a $2.5 million retention.

Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil and gas reserves with the United States Department of Energy ("DOE") for those properties which we operate. During 2009, we filed estimates of our oil and gas reserves as of December 31, 2008 with the DOE, which differ by five percent or less from the reserve data presented in the Annual Report on Form 10-K for the year ended December 31, 2008. For information concerning proved natural gas and crude oil reserves, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Employees

As of February 22, 2010, we had 203 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines, as needed. As of February 22, 2010, we had contracted approximately 22 consultants. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Available Information

Through our website, http://www.rosettaresources.com, you can access, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, our proxy statements, our Code of Business Conduct and Ethics, Nominating and Corporate Governance Committee Charter, Audit Committee Charter, and Compensation Committee Charter. You may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website can be accessed at http://www.sec.gov.

Item 1A. Risk Factors

Broad industry or economic factors may adversely affect the timing of and extent to which we can effectively implement our strategy shift to an onshore unconventional resource player.

Our strategy shift is an important element of positioning us for more predictable, sustainable future performance. In conjunction with pursuing this shift, we recognize that several factors could impact our ability to execute the shift, including: (i) a sustained downturn of commodity prices, (ii) a lack of inventory potential within existing assets, (iii) an inability to attract and retain the personnel necessary to implement an unconventional resource business model, and (iv) a lack of access to credit. We have processes in place to track and monitor these trends on an ongoing basis. At this time, we believe the rationale and the goals for the strategy shift are intact; however, current market conditions could impact the pace of the planned shift.

Adverse capital and credit market conditions may significantly affect our ability to meet liquidity needs, access to capital and cost of capital.

While there are signs that the economy may be improving, the potential remains for further volatility and disruption in the capital and credit markets. During 2009, the markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial strength. If these levels of market disruption and volatility return, our business, financial condition and results of operations, as well as our ability to access capital, may all be negatively impacted.

The deterioration in the credit markets, combined with a decline in commodity prices, may impact our capital expenditure level and also our counterparty risk.

While we seek to fund our capital expenditures primarily from cash flows from operating activities, we have in the past also drawn on unused capacity under our existing revolving credit facility for capital expenditures. While we have not received any indication from our lenders that our ability to draw on our existing revolving credit facility has been restricted, it is possible that our borrowing base, which is based on our oil and gas reserves and is subject to review and adjustment on a semi-annual basis, with the next review scheduled to begin on April 1, 2010, and other interim adjustments, may be reduced when it is reviewed. In the event that our borrowing base is reduced, outstanding borrowings in excess of the revised base will be due immediately. As we do not have a substantial amount of unpledged property, we may not have the financial resources to make the mandatory prepayments. A reduction in our ability to borrow under our existing revolving credit facility, combined with a reduction in cash flow from operating activities resulting from a decline in commodity prices, may require us to reduce our capital expenditures further, which may in turn adversely affect our ability to carry out our business plan. Furthermore, if we lack the resources to dedicate sufficient capital expenditures to our existing oil and gas leases, we may be unable to produce adequate quantities of oil and gas to retain these leases and they may expire due to a lack of production. The loss of leases could have a material adverse effect on our results of operations.

The impairment of financial institutions or counterparty credit default could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds and other institutions. These transactions expose us to credit risk in the event of default by our counterparties. Further deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions in the form of oil and gas derivative contracts, which protect our cash flows when commodity prices decline. During periods of low oil and gas prices, we may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility. Currently, no single lender in our credit facility has commitments representing more than 13% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would significantly affect our financial results and impede our growth. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

Our revenue, profitability and cash flow depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

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- Domestic and foreign supply of oil and natural gas;
- Price and quantity of foreign imports;
- Actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- Consumer demand;
- Conservation of resources;
- Regional price differentials and quality differentials of oil and natural gas;
- Domestic and foreign governmental regulations, actions and taxes;
- Political conditions in or affecting other oil producing and natural gas producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- Weather conditions and natural disasters;
- Technological advances affecting oil and natural gas consumption;
- Overall U.S. and global economic conditions;
- Price and availability of alternative fuels;
- Seasonal variations in oil and natural gas prices;
- Variations in levels of production; and
- The completion of exploration and production projects.

Further, oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because the majority of our estimated proved reserves are natural gas reserves, our financial results are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Thus, a continued weakness in commodity prices may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial position, results of operations and cash flows.

Development and exploration drilling activities do not ensure reserve replacement and thus our ability to produce revenue.

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Development and exploration drilling operations may be curtailed, delayed or cancelled as a result of:

- Lack of acceptable prospective acreage;

- Inadequate capital resources;
- Weather conditions and natural disasters;
- Title problems;
- Compliance with governmental regulations;
- Mechanical difficulties; and
- Unavailability or high cost of equipment, drilling rigs, supplies or services.

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

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We sell a significant amount of our production to one customer.

We have a natural gas purchase and sale contract with CES, which runs through December 2019. Under this contract, we are obligated to sell all of our existing and future production from our California leases in production as of May 1, 2005 at market prices. For the month of December 2009, this dedicated California production comprised approximately 33% of our overall production based on an equivalent unit basis. Additionally, under separate monthly spot agreements, we may sell some of our natural gas production to Calpine, which could increase our credit exposure to Calpine. Under the terms of our contract with CES and spot agreements with CES, all natural gas volumes that are contractually sold to CES are collateralized by CES making margin payments one business day in arrears to our collateral account equal to the previous day's natural gas sales. In the event of a default by CES, we could be exposed to the loss of up to four days of natural gas sales revenue under these contracts, which at prices and volumes in effect as of December 31, 2009 would be approximately $1.0 million.

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

Future projects and acquisitions will depend on our ability to obtain financing beyond our cash flow from operations. We may finance our business plan and operations primarily with internally generated cash flow, bank borrowings and sales of common stock. In the future, we will require substantial capital to fund our business plan and operations. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

The terms of our credit facilities contain a number of covenants. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

The terms of our credit facilities subject us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, make capital expenditures, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, enter into sale and leaseback transactions and pay dividends on our common stock. We are also required by the terms of our credit facilities to comply with financial covenant ratios. A more detailed description of our credit facilities is included in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" and the footnotes to the Consolidated Financial Statements.

A breach of any of the covenants imposed on us by the terms of our indebtedness, including the financial covenants under our credit facilities, could result in a default under such indebtedness. In the event of a default, the lenders for our revolving credit facility could terminate their commitments to us, and they and the lenders of our second lien term loan could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders under the credit facilities could proceed against the collateral securing the facilities, which is substantially all of our assets. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

Properties we acquire may not produce as expected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects; however, such reviews are not capable of identifying all potential conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on higher value properties or properties with known adverse conditions and will sample the remainder.

However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination are not necessarily observable even when an inspection is undertaken.

We believe we have good and defensible title to all our properties, including those held by production. As is customary in the industry, before we drill our exploration and development wells, we secure external legal opinions on our legal title for the properties involved. We also may perform curative work with respect to significant defects to title. We are typically responsible for curing any title defects at our expense. This curative work may include the acquisition of additional property rights in order to perfect our ownership for development and production of the mineral estate. We also may be required to respond to claims regarding possible threats to our title to our properties, including clouds on our title, concerning which, if we are unsuccessful could result in the worst case, to the loss of our title. In those situations, we are subject to increased costs in defending our title against possible claims and if we are unsuccessful in this regard, possible damages, including amounts of revenues from prior production during those time periods for which a claim for revenue may be brought.

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Our exploration and development activities may not be commercially successful.

Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- Unexpected drilling conditions; pressure or irregularities in formations; equipment failures or accidents;
- Adverse weather conditions, including hurricanes, which are common in the Gulf of Mexico during certain times of the year; compliance with governmental regulations; unavailability or high cost of drilling rigs, equipment or labor;
- Possible federal, state, regional and municipal regulatory moratoriums on new permits, delays in securing new permits, changes to existing permitting requirements without "grandfathering" of existing permits and possible prohibition and limitations with regard to certain completion activities;
- Reductions in oil and natural gas prices; and
- Limitations in the market for oil and natural gas.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future financial position, results of operations and cash flows.

Numerous uncertainties are inherent in our estimates of oil and natural gas reserves and our estimated reserve quantities and present value calculations may not be accurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the estimated quantities and present value of our reserves.

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by our engineers and audited by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our engineers' control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices, expenditures for future development and exploration activities, engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and natural gas. As an example, our internally generated reserve report for year end 2009 includes the downward revision of 60.5 Bcfe of proved reserves due to the use of the twelve-month first day of the month historical average price compared to year-end commodity prices, or approximately 15% of previously estimated reserves. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The present value of future net revenues from our proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Our reserves as of December 31, 2009 were based on the twelve-month first day of the month historical average West Texas Intermediate oil prices adjusted for basis and quality differentials of $57.65 per Bbl and the twelve-month first day of the month historical average Henry Hub gas prices adjusted for basis and quality differentials of $3.87 per MMbtu compared to the year-end prices adjusted for basis and quality differentials of $41.00 per Bbl and $5.71 per MMBtu, respectively, at December 31, 2008. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming royalties to the Minerals Management Service, royalty owners and other state and federal regulatory agencies with respect to our affected properties, and will be paid or suspended during the life of the properties based upon oil and natural gas prices as of the date of the estimate. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the net present value of future net cash flows for reporting purposes in accordance with the SEC's rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry, in general, will affect the appropriateness of the 10% discount factor in arriving at an accurate net present value of future net cash flows.

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We are subject to the full cost ceiling limitation which has resulted in a write-down of our estimated net reserves and may result in a write-down in the future if commodity prices continue to decline.

Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The current ceiling calculation utilizes a twelve-month first day of the month historical average price and does not allow for us to re-evaluate the calculation subsequent to the end of the period if prices increase. It also dictates that costs in effect as of the last day of the quarter are held constant. Prior to December 31, 2009, ceiling calculation guidance dictated that prices in effect as of the last day of the quarter or annual period be used and allowed a write-down to be reduced or avoided if prices increased subsequent to the end of a quarter or annual period but prior to the issuance of our financial statements in which a write-down might otherwise be required. As of December 31, 2009, the use of the recovery of prices after the end of the period is no longer permitted. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. Expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period.

For the year ended December 31, 2009, we recognized a non-cash, pre-tax ceiling test impairment of $379.5 million in the first quarter. For the year ended December 31, 2008, we recognized a non-cash, pre-tax ceiling test impairment of $205.7 million and $238.7 million in the third and fourth quarters, respectively. Due to the volatility of commodity prices, should natural gas prices continue to decline in the future, it is possible that additional write-downs could occur.

In addition, write-downs of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. For example, we recognized a downward revision to our proved reserves in the third and fourth quarters of 2008. As we are continuing to evaluate and test our asset base, it is possible that we may recognize additional revisions to our proved reserves in the future.

See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates" for further information.

Government laws and regulations can change.

Our activities are subject to federal, state, regional and local laws and regulations. Extensive laws, regulations and rules relate to activities and operations in the oil and gas industry. Some of the laws, regulations and rules contain provisions for significant fines and penalties for non-compliance. Changes in laws and regulations could affect our costs of operations and our profitability. Changes in laws and regulations could also affect production levels, royalty obligations, price levels, environmental requirements, and other matters affecting our business. We are unable to predict changes to existing laws and regulations or additions to laws and regulations. Such changes could significantly impact our business, results of operations, cash flows, financial position and future growth.

Our business requires a sufficient level of staff with technical expertise, specialized knowledge and training and a high degree of management experience.

Our success is largely dependent upon our ability to attract and retain personnel with the skills and experience required for our business. An inability to sufficiently staff our operations or the loss of the services of one or more members of our senior management or of numerous employees with technical skills could have a negative effect on our business, financial position, results of operations, cash flows and future growth.

Market conditions or transportation impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions, the unavailability of satisfactory oil and natural gas processing and transportation or the remote location of certain of our drilling operations may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. In the Gulf of Mexico operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. Under interruptible or short term transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system or for other reasons specified by the particular agreements. We may be required to shut in natural gas wells or delay initial production for lack of a market or because of inadequacy or unavailability of natural gas pipelines or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

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Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Many of our competitors, major and large independent oil and natural gas companies, possess and employ financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. If oil and gas prices increase in the future, increasing levels of exploration and production could result in response to these stronger prices, and as a result, the demand for oilfield services could rise, and the costs of these services could increase, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in Texas, California and the Rockies, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and natural gas business involves certain operating hazards such as:

- Well blowouts;
- Cratering;
- Explosions;
- Uncontrollable flows of oil, natural gas, or well fluids;
- Fires;
- Hurricanes, tropical storms, earthquakes, mud slides, and flooding;
- Pollution; and
- Releases of toxic gas.

The occurrence of one of the above may result in injury, loss of life, property damage, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties.

In addition, our operations in California are especially susceptible to damage from natural disasters such as earthquakes and fires and involve increased risks of personal injury, property damage and marketing interruptions. Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition, or could result in a loss of our properties. Our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. For example, we are not fully insured against earthquake risk in California because of high premium costs. Insurance covering earthquakes or other risks may not be available at premium levels that justify its purchase in the future, if at all. In addition, we are subject to energy package insurance coverage limitations related to any single named windstorm. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs could increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur a liability at a time when we are not able to obtain liability insurance, then our business, financial position, results of operations and cash flows could be materially adversely affected. Because of the expense of the associated premiums and the diversification of risk, we do not have any insurance coverage for any loss of production as may be associated with these operating hazards.

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Environmental matters and costs can be significant.

The oil and natural gas business is subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. Such laws and regulations may impose liability on us for pollution clean-up, remediation, restoration and other liabilities arising from or related to our operations. Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production. We also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. The cost of future compliance is uncertain and is subject to various factors, including future changes to laws and regulations. We have no assurance that future changes in or additions to the environmental laws and regulations will not have a significant impact on our business, results of operations, cash flows, financial condition and future growth.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to the warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. The U.S. Congress is considering climate-related legislation to reduce emissions of greenhouse gases. In addition, at least 20 states have developed measures to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The U.S. Environmental Protection Agency has adopted regulations requiring reporting of greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of regulations by the EPA or analogous state agencies, that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect on our operations and the demand for oil and natural gas.

Our acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy includes acquiring oil and natural gas businesses and properties if favorable economics and strategic objectives can be served. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully.

Furthermore, acquisitions involve a number of risks and challenges, including:

- Diversion of management’s attention;
- Ability or impediments to conducting thorough due diligence activities;
- The need to integrate acquired operations;
- Potential loss of key employees of the acquired companies;
- Potential lack of operating experience in a geographic market of the acquired business; and
- An increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses and properties or realize other anticipated benefits of those acquisitions.

We are vulnerable to risks associated with operating in the Gulf of Mexico and inland waters region.

Our operations and financial results could be significantly impacted by unique conditions in the Gulf of Mexico and inland waters region because we explore and produce in that area. As a result of this activity, we are vulnerable to the risks associated with operating in the Gulf of Mexico and inland waters region, including those relating to:

- Adverse weather conditions and natural disasters;
- Availability of required performance bonds and insurance;
- Oil field service costs and availability;
- Compliance with environmental and other laws and regulations;
- Remediation and other costs resulting from oil spills or releases of hazardous materials; and
- Failure of equipment or facilities.

Further, production of reserves from reservoirs in the Gulf of Mexico and inland waters region generally decline more rapidly than from fields in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties during the initial years of production, and as a result, our reserve replacement needs from new prospects may be greater there than for our operations elsewhere. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods.

Hedging transactions may limit our potential revenue, result in financial losses or reduce our income.

We have entered into natural gas price hedging arrangements with respect to a portion of our expected production through 2011. As of December 31, 2009, 13% and 13% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2010, and 5% and 23% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2011, based on anticipated future gas production. The swaps to settle in 2010 have an average price of $7.46 per MMBtu and the collars have floor and ceiling prices of $5.75 per MMBtu and $7.40 per MMBtu, respectively. The swaps to settle in 2011 have an average price of $5.72 per MMBtu and the collars have floor and ceiling prices of $5.80 per MMBtu and $7.58 per MMBtu, respectively. In January 2010, we entered into additional costless collar transactions to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2012. The costless collars have a floor price of $5.75 per MMBtu and a ceiling price of $6.50 per MMBtu through 2011 and $7.15 per MMBtu in 2012. In February 2010, we entered into natural gas fixed-price swaps to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2011 at an average price of $5.91 per MMBtu. Such transactions may limit our potential revenue if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement, or the counterparties to our hedging agreements fail to perform under the contracts. Our current hedge positions are with counterparties that are lenders in our credit facilities. Our lenders are comprised of banks and financial institutions that could default or fail to perform under our contractual agreements. A default under any of these agreements could negatively impact our financial performance.

We have also entered into a series of interest rate swap agreements to hedge the change in the variable interest rates associated with our debt under our credit facility. If interest rates should fall below the rate established in the hedge, we will not receive the benefit of the lower interest rates.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in the President’s Fiscal Year 2011 budget proposal, released by the White House on February 1, 2010, is the elimination or deferral of certain key U.S. federal income tax deductions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Additionally, the Senate version of the Oil Industry Tax Break Repeal Act of 2009, introduced on April 23, 2009, the Senate version of the Energy Fairness for America Act, introduced on May 20, 2009 and the President's Fiscal Year 2010 budget proposal, released on February 26, 2009, include many of the proposals outlined in the President's Fiscal Year 2011 budget proposal. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation as a result of the budget proposal, either Senate bill or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Item 1B. Unresolved Staff Comments

None

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Item 3. Legal Proceedings

Wyoming Air Permit. On February 12, 2010, we received a Notice of Violation ("Notice") from the Wyoming Department of Environmental Quality ("Wyoming DEQ") regarding a multiple wellsite facility for wet gas/condensate production and six associated wells located in Sublette County, Wyoming (collectively, the "Wellsite"). The Notice alleges that we did not obtain a construction permit prior to constructing the Wellsite, and that we operated the Wellsite in violation of applicable regulations by allegedly having failed to control air emissions from six associated wells. The Notice threatens referral of this matter to the Wyoming Attorney General for "appropriate penalties," which could include civil penalties or injunctive relief. We have responded to the Notice, are in the process of implementing corrective action and have agreed with the Wyoming DEQ to discuss possible settlement of this matter. If we do not reach a settlement, we will contest any associated litigation. No civil penalties have been imposed nor has the Wyoming DEQ yet requested a specific civil penalty amount, although the maximum daily penalty for such violations is $10,000 per violation per day. Given the preliminary stage of this matter and the inherent uncertainty of enforcement actions of this nature, the Company is presently unable to predict the ultimate outcome of this enforcement action.

We are party to various other oil and natural gas litigation matters arising out of the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, we do not expect these other matters to have a material adverse effect on the consolidated financial statements.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of our security holders during the fourth quarter of 2009.

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Part II

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

Trading Market

Our common stock is listed on The NASDAQ Global Select Market® under the symbol "ROSE". The following table sets forth for the 2009 and 2008 periods indicated the high and low sale prices of our common stock:

	2009 High	2009 Low		2008 High	2008 Low
January 1 - March 31	$ 8.37	$ 3.52	January 1 - March 31	$ 21.42	$ 16.20
April 1 - June 30	10.17	4.81	April 1 - June 30	29.65	19.15
July 1 - September 30	15.60	7.08	July 1 - September 30	29.20	16.67
October 1 - December 31	20.62	12.35	October 1 - December 31	18.23	5.97

The number of shareholders of record on February 24, 2010 was approximately 10,500. However, we estimate that we have a significantly greater number of beneficial shareholders because a substantial number of our common shares are held of record by brokers or dealers for the benefit of their customers.

We have not paid a cash dividend on our common stock and currently intend to retain earnings to fund the growth and development of our business. Any future change in our policy will be made at the discretion of our board of directors in light of our financial condition, capital requirements, earnings prospects and any limitations imposed by our lenders or investors, as well as other factors the Board of Directors may deem relevant. Our Senior Secured Revolving Line of Credit agreement restricts our ability to pay cash dividends on our common stock. See Item 8. "Financial Statements and Supplementary Data Note 10 – Long-Term Debt."

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2009:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs
October 1 - October 31	2,700	$ 14.46	-	-
November 1 - November 30	10,043	13.77	-	-
December 1 - December 31	351	16.47	-	-

(1) All of the shares were surrendered by our employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of common stock.

Stock Performance Graph

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

The following common stock performance graph shows the performance of Rosetta Resources Inc. common stock up to December 31, 2009. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

- A $100 investment was made in Rosetta Resources Inc. common stock at the opening trade price of $19.00 per share on February 13, 2006 (the first full trading day following the Company’s initial public offering of its common stock), and $100 was invested in each of the Standard & Poor’s 500 Index (S&P 500) and the Standard & Poor’s MidCap 400 Oil & Gas Exploration & Production Index (S&P 400 E&P) at the opening price on February 13, 2006.
- All dividends are reinvested for each measurement period.

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The S&P 400 E&P Index is widely recognized in our industry and includes a representative group of independent peer companies (weighted by market capital) that are engaged in comparable exploration, development and production operations.

Total Return Among Rosetta Resources Inc., the S&P 500 Index and the S&P 400 O&G E&P Index

	2/13/2006 (1)	12/31/2006	12/31/2007	12/31/2008	12/31/2009
ROSE	$ 100.00	$ 98.26	$ 104.37	$ 37.26	$ 104.84
S&P 500	100.00	113.86	120.12	75.67	95.70
S&P 400 E&P	100.00	103.24	149.13	67.84	120.86

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(1) February 13, 2006 was the first full trading day following the effective date of our registration statement filed in connection with our initial public offering.

Item 6. Selected Financial Data

The following table sets forth our selected financial data. For the years ended December 31, 2009, 2008, 2007 and 2006 and the six months ended December 31, 2005 (Successor), the financial data has been derived from the consolidated financial statements of Rosetta Resources Inc. For the six months ended June 30, 2005 (Predecessor), the financial data was derived from the combined financial statements of the domestic oil and natural gas properties of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and natural gas business. You should read the following selected historical consolidated/combined financial data in connection with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

Additionally, the historical financial data reflects successful efforts accounting for oil and natural gas properties for the Predecessor periods described above and the full cost method of accounting for oil and natural gas properties effective July 1, 2005 for the Successor periods. In addition, on January 1, 2003, Calpine adopted authoritative guidance regarding the accounting for stock-based compensation to measure the cost of employee services received in exchange for an award of equity instruments, whereas we adopted the intrinsic value method of accounting for stock options and stock awards pursuant to authoritative guidance regarding stock issued to employees effective July 2005, and as required, have subsequently adopted the guidance for stock-based compensation under the most recent authoritative guidance for share-based payments effective January 1, 2006.

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	Successor-Consolidated					Predecessor - Combined
	Year Ended December 31,				Six Months Ended December 31,	Six Months Ended June 30,
	2009 (1)	2008 (1)	2007	2006	2005	2005
Operating Data:						
Total revenue	$293,951	$499,347	$363,489	$271,763	$113,104	$103,831
Net income (loss)	(219,176)	(188,110)	57,205	44,608	17,535	18,681
Income (loss) per share:						
Net income (loss)						
Basic	(4.30)	(3.71)	1.14	0.89	0.35	0.37
Diluted	(4.30)	(3.71)	1.13	0.88	0.35	0.37
Cash dividends declared per common share	-	-	-	-	-	-
Balance Sheet Data (At the end of the Period)						
Total assets	879,584	1,154,378	1,357,214	1,219,405	1,119,269	-
Long-term debt	288,742	300,000	245,000	240,000	240,000	-
Stockholders' equity	493,095	726,372	872,955	822,289	715,423	-

(1) Includes a $379.5 million and a $444.4 million non-cash, pre-tax impairment charge for the years ended December 31, 2009 and 2008, respectively.

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

Overview

During the past two years, Rosetta significantly transformed itself as a company. The actions taken to affect this business shift were underpinned by a relatively straightforward goal: to position the Company for visible and sustainable future growth. We believe that achieving this goal is essential in order for Rosetta to create long-term shareholder value. As part of our transformation, we took many steps to improve the underlying fundamentals of virtually every aspect of our business. Most notably, we committed to building a portfolio of high quality unconventional assets with significant project inventory potential. In addition, we sought to establish the technical and organizational competencies required for executing a resource-driven business model. These asset and competency efforts were matched with a fiscal approach that maintained relative conservatism and a focus on cost control and efficiency. While we will continue to evolve and optimize each of these areas over time, we believe we made significant progress in transforming Rosetta into a "resource-player" since the effort began in early 2008.

We believe that our 2009 performance offers tangible evidence that our strategy shift is yielding success. Against one of the most challenging business climates in years, we lived within our means while delivering results from our activities in new and legacy asset programs. Of significance, we note the following highlights with respect to our performance in 2009:

- We tested two new shale plays, namely the Eagle Ford Shale in South Texas and the Alberta Basin Bakken Shale in Montana. In the Eagle Ford, we grew our acreage position and drilled four wells in the play. We completed two wells, both of which were discoveries. The discoveries set up the potential for a significant future development effort that will start in 2010.

- In the Alberta Basin Bakken Shale, we drilled two wells on our large exploratory acreage position. We drilled and completed one horizontal well and drilled one additional vertical well. We acquired core samples and ran extensive log suites in both wells to obtain important geologic and reservoir data about the play. Since we consider this early stage exploration, we intend to fully analyze and evaluate our drilling, completion and logging results in order to optimize our 2010 program activity.
- In addition to testing our new shale plays, we advanced the studies of our legacy assets using an “unconventional lens” approach. Under this approach, our assets are thoroughly analyzed and re-engineered to identify remaining resource potential. We believe our legacy onshore assets, especially the DJ Basin and the Sacramento Basin, contain significant remaining resource potential that was overlooked under a historical exploitation approach that utilized conventional techniques. We believe the project inventory potential of our legacy assets is a competitive advantage for Rosetta.
- We identified assets for possible sale and established an ongoing process to divest of non-core assets. During 2009, we designated our Gulf of Mexico, Texas State Waters and several small assets as “non-core” given that they do not have the unconventional resource characteristics we seek. We generated approximately $20 million of proceeds from sales of a portion of our non-core assets in 2009.
- In addition to asset sales, we took other measures to ensure our financial flexibility during the year. We monitored capital program results on a continuous basis and shifted or adjusted spending as necessary. We refinanced our existing debt and extended our maturities. We hedged selectively during the latter part of 2009 into a period of relative commodity price strength.

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In 2009, our portfolio actions, in combination with prudent fiscal measures, strengthened our ability to deliver on the visible and sustainable growth that we are striving for as a resource player. Accordingly, we believe we enter 2010 at an inflection point on performance. We believe that we are in the relatively early stages of creating value from our meaningful positions in the new Eagle Ford and Alberta Basin Bakken shale plays. With success in either or both of these plays, we could recognize significant reserve and production upside to our current levels. Furthermore, success in either or both of these plays could shift our product mix toward a higher percentage of oil, which would provide attractive diversification for Rosetta. Finally, we believe the inventory potential from our legacy onshore assets provides a high-value base of production and reserves with relatively low capital intensity. In combination with our new shale plays, we believe Rosetta possesses a unique combination of assets for a company of our size.

Our business goals for 2010 are predicated on an announced 2010 capital program of $280 million, subject to program results and timing. We expect to initiate development activities in the Eagle Ford, where our efforts will likely focus in the condensate-prone area surrounding our 2009 Gates Ranch discovery. We expect to continue testing our Alberta Basin Bakken position, as well as conduct modest programs in several legacy assets. We intend to continue our effort to build lease positions in existing core areas, if possible, but also to pursue entry into new basins of interest. We prefer organic opportunities, but we are also expanding our capability to evaluate and pursue acquisition opportunities that fit our business model. We believe this balanced approach is appropriate for long-term success; however, it is not our intention or desire to pursue acquisitions solely for the sake of growth, but rather that fit our strategic and economic objectives.

We recognize that, despite what we believe was a successful year in 2009, the operating environment for our industry continues to be somewhat uncertain and Rosetta's success in 2010 or beyond is not assured. Commodity prices, particularly for natural gas, continue to be impacted by anemic demand and the lack of a meaningful supply response to lower prices in 2009. Access to some oilfield services are starting to tighten. Attractive acquisitions or leasing opportunities remain extremely competitive. Finally, given the early stage of the Eagle Ford and Alberta Basin Bakken plays, there is still significant risk to those programs. We attempt to manage these risks by carefully monitoring the environment, working closely with our suppliers and vendors, staying abreast of the marketplace, and moving at a deliberative pace in our new play programs. Nevertheless, regardless of how effectively we manage these risks, they represent threats to our ability to achieve our growth goals and build our asset base.

In approving our 2010 capital budget of $280 million, we indicated that the program could be funded from internally generated cash flows plus cash on hand at an average gas price of roughly $6 per Mcf and an average oil price of roughly $70 per Bbl. In that price environment, we believe that we have sufficient liquidity and operational flexibility at this time to fund and actively manage our stated capital expenditures program. We monitor our liquidity situation continuously. We intend to maintain a position in which we can execute prudent and timely decisions should commodity prices, services costs, or market conditions change. In the event that we encounter a situation in which we do not have sufficient internal funds to execute our planned capital program, fund incremental organic opportunities or pursue attractive acquisitions, we would consider curtailing our capital spending, drawing on the unused capacity under our existing revolving credit facility or accessing capital markets. As of December 31, 2009, we had $160.0 million of available borrowing capacity under our revolving credit facility. We have not received any indication from our lenders that draws under the credit facility are restricted below current availability at this time and we are proactively communicating with them on a routine basis. We affirmed our borrowing base in the third quarter of 2009 at $350.0 million and the next redetermination is scheduled to begin in March 2010. Our ability to raise additional capital depends on the current state of the financial markets, which are subject to general economic and industry conditions. Therefore, the availability and price of capital in the financial markets could negatively affect our liquidity position and cost of borrowed money.

In order to ensure that Rosetta preserves the necessary financial flexibility, we work closely with our lenders to stay abreast of market and creditor conditions. Of note, our capital expenditures are primarily in areas where Rosetta acts as operator and has high working interests. As a result, we do not believe we have significant exposure to joint interest partners who may be unable to fund their portion of any capital program, but we monitor partner situations routinely.

Financial Highlights

Our consolidated financial statements reflect total revenue of $294.0 million on total volumes of 50.6 Bcfe for the year ended December 31, 2009. Operating loss for the year ended December 31, 2009 was $326.7 million and included depreciation, depletion and amortization ("DD&A") expense of $121.0 million, a non-cash, pre-tax full cost ceiling test impairment charge of $379.5 million, lease operating expense of $60.8 million and $7.5 million of compensation expense for stock-based compensation granted to employees included in General and administrative costs. Total net other income for the year ended December 31, 2009 was comprised of interest expense (net of capitalized interest) on our long-term debt offset by interest income on short-term cash investments.

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Results of Operations

The following table summarizes the components of our revenues for the periods indicated, as well as each period's production volumes and average prices:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas sales	$ 250,684	$ 398,268	$ 295,644
Oil sales	21,763	55,736	40,148
NGL sales	21,504	45,343	27,697
Total revenues	$ 293,951	$ 499,347	$ 363,489
Production:			
Gas (Bcf)	44.5	47.7	39.1
Oil (MBbls)	393.9	546.4	561.2
NGLs (MBbls)	620.1	440.8	557.0
Total equivalents (Bcfe)	50.6	53.6	45.8
$ per unit:			
Avg. gas price per Mcf	$ 5.63	$ 8.35	$ 7.56
Avg. gas price per Mcf excluding hedging	3.91	8.74	6.97
Avg. oil price per Bbl	55.25	102.00	71.54
Avg. NGL price per Bbl	34.68	102.87	49.73
Avg. revenue per Mcfe	5.81	9.32	7.94

Revenues

Our revenues are derived from the sale of our oil and natural gas production, which includes the effects of qualifying commodity hedge contracts. Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Total revenue for the year ended December 31, 2009 was $294.0 million, which is a decrease of $205.4 million, or 41%, from the year ended December 31, 2008. Approximately 85% of revenue was attributable to natural gas sales.

Natural Gas. For the year ended December 31, 2009, natural gas revenue decreased by 37%, or $147.6 million, including the realized impact of derivative instruments, from the comparable period in 2008, to $250.7 million. Of this decrease, $27.1 million is attributable to decreased volumes and $120.5 million is attributable to lower average realized prices in 2009. The average realized natural gas price including the effects of hedging decreased 33%, or $2.72, to $5.63 per Mcf for the year ended December 31, 2009 as compared to $8.35 per Mcf for the same period in 2008. In 2009, the Henry Hub natural gas spot price averaged $3.87 per Mcf compared to the 2008 average of $9.13 per Mcf. The effect of gas hedging activities on natural gas revenue for the year ended December 31, 2009 was an increase of $76.6 million, or an increase of $1.72 per Mcf, as compared to a decrease of $18.7 million, or a decrease of $0.39 per Mcf, for the year ended December 31, 2008. Production volumes decreased overall by 7%, or 3.2 Bcf for the year ended December 31, 2009, primarily due to natural decline in our non-core Gulf of Mexico properties as well as the suspension of drilling programs during 2009 in areas where we were active during 2008 as well as the suspension of non-essential workover and recompletion activity in all areas for a portion of 2009 for the purpose of cash management during the industry downturn.

Crude Oil. For the year ended December 31, 2009, oil revenue decreased by 61%, or $34.0 million, primarily due to the decrease of $46.75 per Bbl in the average oil price from $102.00 per Bbl for the year ended December 31, 2008 as compared to $55.25 per Bbl for the year ended December 31, 2009. Oil volumes also decreased by 28%, or 152.5 MBbls, to 393.9 MBbls for the year ended December 31, 2009 from 546.4 MBbls for the year ended December 31, 2008. The decrease in oil production volumes was due to natural decline in our non-core Gulf of Mexico and Texas State Waters properties.

NGLs. For the year ended December 31, 2009, NGL revenue decreased by 53%, or $23.8 million, primarily due to the decrease of $68.19 per Bbl in the average NGL price from $102.87 per Bbl for the year ended December 31, 2008 as compared to $34.68 per Bbl for the year ended December 31, 2009. NGL volumes increased by 41%, or 179.3 MBbls, to 620.1 MBbls for the year ended December 31, 2009 from 440.8 MBbls for the year ended December 31, 2008. The increase in NGL production volumes was due to the recognition in 2009 of processed liquid volumes for the first time from our Lobo trend properties.

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Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Total revenue for the year ended December 31, 2008 was $499.3 million, which is an increase of $135.9 million, or 37%, from the year ended December 31, 2007. Approximately 80% of revenue was attributable to natural gas sales.

Natural Gas. For the year ended December 31, 2008, natural gas revenue increased by 35%, or $102.6 million, including the realized impact of derivative instruments, from the comparable period in 2007, to $398.3 million. Of this increase, $37.6 million is attributable to increased volumes and $65.0 million is attributable to favorable average realized prices in 2008. Production volumes for the year ended December 31, 2008 increased by 22%, or 8.6 Bcf, primarily due to the increase in the number of productive wells during 2008. Net productive wells increased from 606 in 2007 to 825 in 2008. The effect of gas hedging activities on natural gas revenue for the year ended December 31, 2008 was a decrease of $18.7 million, or a decrease of $0.39 per Mcf, as compared to an increase of $22.9 million, or an increase of $0.59 per Mcf, for the year ended December 31, 2007. The average realized natural gas price including the effects of hedging increased 10% or $0.79 per Mcf to $8.35 per Mcf for the year ended December 31, 2008 as compared to the same period in 2007 of $7.56 per Mcf. In 2008, the Henry Hub natural gas spot price averaged $9.13 per Mcf compared to the 2007 average of $7.17 per Mcf.

Crude Oil. For the year ended December 31, 2008, oil revenue increased by 39%, or $15.6 million, primarily due to the increase of $30.46 per Bbl in the average oil price from $71.54 per Bbl for the year ended December 31, 2007 as compared to $102.00 per Bbl for the year ended December 31, 2008. At December 31, 2008, the West Texas Intermediate price for oil was $41.00 per Bbl compared to $92.50 per Bbl at December 31, 2007. Oil volumes decreased by 3%, or 14.8 MBbls, to 546.4 MBbls for the year ended December 31, 2008 from 561.2 MBbls for the year ended December 31, 2007. The decrease in oil production volumes in 2008 was associated with decreased production in the Gulf of Mexico primarily due to the effects of Hurricane Ike and Sabine Lake well work in September 2008 as well as lower production in Other Onshore.

NGLs. For the year ended December 31, 2008, NGL revenue increased by 64%, or $17.6 million, primarily due to the increase of $53.14 per Bbl in the average NGL price from $49.73 per Bbl for the year ended December 31, 2007 as compared to $102.87 per Bbl for the year ended December 31, 2008. NGL volumes decreased by 21%, or 116.2 MBbls, to 440.8 MBbls for the year ended December 31, 2008 from 557.0 MBbls for the year ended December 31, 2007. The decrease in NGL production volumes was associated with the effects of Hurricane Ike in the Gulf of Mexico and Sabine Lake.

Operating Expenses

The following table summarizes our production costs and operating expenses for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per unit amounts)		
Lease operating expense	$60,773	$55,694	$47,044
Production taxes	6,131	13,528	6,417
Depreciation, depletion and amortization	121,042	198,862	152,882
Impairment of oil and gas properties	379,462	444,369	-
General and administrative costs	46,993	52,846	43,867
$ per unit:			
Avg. lease operating expense per Mcfe	$1.20	$1.04	$1.03
Avg. production taxes per Mcfe	0.12	0.25	0.14

Avg. DD&A per Mcfe	2.39	3.71	3.34
Avg. production costs per Mcfe (1)	3.59	4.75	4.36
Avg. G&A per Mcfe	0.93	0.99	0.96

(1) Production costs per Mcfe include lease operating expense and DD&A.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Lease Operating Expense. Lease operating expense increased $5.1 million for the year ended December 31, 2009 as compared to the same period for 2008. This overall increase is primarily due to the 2008 South Texas Constellation, Pinedale and Petroflow acquisitions as 2009 was the first full year of recording expenses. Lease operating expense includes workover costs of $0.08 per Mcfe, ad valorem taxes of $0.29 per Mcfe and insurance of $0.03 per Mcfe for the year ended December 31, 2009 as compared to workover costs of $0.14 per Mcfe, ad valorem taxes of $0.21 per Mcfe and insurance of $0.03 per Mcfe for the same period in 2008.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 2.1% for the year ended December 31, 2009 as compared to 2.7% for the year ended December 31, 2008. This decrease is the result of decreased production and prices for the year ended December 31, 2009 as compared to the same period for 2008.

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Depreciation, Depletion, and Amortization. DD&A expense decreased $77.8 million for the year ended December 31, 2009 as compared to the same period for 2008. The decrease is due to a 6% decrease in total production and a lower DD&A rate for 2009 compared to 2008 due to the full cost ceiling test impairment charges recognized during the second half of 2008 and during the first quarter of 2009, which decreased the full cost pool. The DD&A rate for the year ended December 31, 2009 was $2.39 per Mcfe while the rate for the year ended December 31, 2008 was $3.71 per Mcfe.

Impairment of Oil and Gas Properties. Based upon the quarterly ceiling test computations using hedge adjusted market prices during the year ended December 31, 2009, at March 31, 2009, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling and a pre-tax, non-cash impairment expense of $379.5 million was recorded. There was no impact on the ceiling test of applying the new SEC guidance. Whereas based upon the quarterly ceiling test computations using hedge adjusted market prices during the year ended December 31, 2008, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling and a pre-tax, non-cash impairment expense of $444.4 million was recorded.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead costs of $4.8 million, decreased by $5.9 million for the year ended December 31, 2009 as compared to the same period for 2008. The decrease in general and administrative costs incurred in the current period is primarily related to decreases of $12.1 million in legal fees related to the Calpine litigation, which settled during 2008, and an increase of $1.4 million in billable field personnel offset by a $3.1 million decrease in capitalizable geological and geophysical expenses, a $2.2 million increase in salaries and wages resulting from the additional technical personnel hired during 2009 and a $2.7 million increase in bonus expense.

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Lease Operating Expense. Lease operating expense increased $8.7 million for the year ended December 31, 2008 as compared to the same period for 2007. This overall increase is primarily due to the increase in the number of productive wells as well as increased production of 17% for 2008 which led to higher costs for equipment rentals, maintenance and repairs, and costs associated with non-operated properties. Lease operating expense includes workover costs of $0.14 per Mcfe, ad valorem taxes of $0.21 per Mcfe and insurance of $0.03 per Mcfe for the year ended December 31, 2008 as compared to workover costs of $0.11 per Mcfe, ad valorem taxes of $0.26 per Mcfe and insurance of $0.05 per Mcfe for the same period in 2007.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 2.7% for the year ended December 31, 2008 as compared to 1.8% for the year ended December 31, 2007. This increase is the result of increased production in areas that do not qualify for tax credits for the year ended December 31, 2008 as compared to the same period for 2007.

Depreciation, Depletion, and Amortization. DD&A expense increased $46.0 million for the year ended December 31, 2008 as compared to the same period for 2007. The increase is due to a 17% increase in total production and a higher DD&A rate for 2008 due to the decrease in oil and natural gas reserves as compared to 2007. The DD&A rate for the year ended December 31, 2008 was $3.71 per Mcfe while the rate for the year ended December 31, 2007 was $3.34 per Mcfe due to the increase in finding costs.

Impairment of Oil and Gas Properties. Based upon the quarterly ceiling test computations using hedge adjusted market prices during the year ended December 31, 2008, and in conjunction with the downward revisions of a portion of our reserves in the third and fourth quarters of 2008, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling and a pre-tax, non-cash impairment expense of $444.4 million was recorded. There were no ceiling test impairments during the year ended December 31, 2007.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead costs of $7.1 million, increased by $9.0 million for the year ended December 31, 2008 as compared to the same period for 2007, with capitalized exploration and development overhead costs of $5.5 million. The increase in costs incurred in 2008 were primarily related to increases in legal fees related to the Calpine litigation of $6.9 million and increases in payroll expenses of $2.1 million resulting from increased headcount and a $1.3 million accrual related to the severance of a former executive officer, as well as the absence of approximately $5.0 million in CEO transition costs that were incurred in 2007 but not 2008.

Total Other Expense

Other expense includes interest expense, interest income and other income/expense, net which decreased $7.3 million for the year ended December 31, 2009 as compared to the same period in 2008. The decrease in other expense is primarily the result of a $12.4 million charge related to the settlement of litigation with Calpine in 2008 for which there were no related expenses during 2009 offset by a $4.6 million increase in interest expense due to higher interest rates on the restated credit facilities and increased amortization of deferred loan fees and original issue discount related to the restated credit facilities during the first quarter of 2009.

Other expense increased $10.2 million for the year ended December 31, 2008 to $25.6 million as compared to $15.4 million in the same period in 2007. The increase in other expense was the result of a $12.4 million charge related to the Calpine Settlement partially offset by $3.0 million decrease in interest expense in 2008.

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Provision for Income Taxes

Our 2009 income tax benefit of $125.8 million was primarily due to the first quarter ceiling test write-down. For the year ended December 31, 2009, the effective tax rate was 36.5% compared to the effective tax rate of 37.5% for the year ended December 31, 2008 and 37.3% for the year ended December 31, 2007. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate primarily due to the effect of state taxes, a tax shortfall arising from our deferred compensation plans, and other permanent differences.

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2009, we have a deferred tax asset of approximately $169.7 million resulting primarily from the difference between the book basis and tax basis of our oil and natural gas properties compared to a deferred tax asset of approximately $42.7 million at December 31, 2008. We have concluded that it is more likely than not that this deferred tax asset will be realized through future taxable income generated by the production of our oil and natural gas properties.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow. We also maintain a revolving line of credit, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising natural gas prices. The effects of these derivative transactions on our natural gas sales are discussed above under "Results of Operations – Natural Gas." The majority of our capital expenditures is discretionary and could be curtailed if our cash flows decline from expected levels. Current economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program.

Senior Secured Revolving Line of Credit. On April 9, 2009, we amended and restated our revolving credit agreement (the "Restated Revolver") with BNP Paribas, as Administrative Agent, and the other lenders identified therein to provide for a senior secured revolving line of credit in the amount of up to $600.0 million and to extend its term until July 1, 2012. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements. Our borrowing base is dependent on a number of factors, including our level of reserves as well as the pricing outlook at the time of the redetermination. A reduction in capital spending could result in a reduced level of reserves thus causing a reduction in the borrowing base. After the redetermination in October 2009, the borrowing base under the Restated Revolver is $350.0 million. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.25% to 3.00%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of our domestic subsidiaries, and a pledge of 100% of the membership interests of domestic subsidiaries. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2009, our current ratio was 4.3 and the leverage ratio was 1.6. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2009. As of February 26, 2010, we had $190.0 million outstanding, which is due and payable on July 1, 2012, with $160.0 million available for borrowing under the Restated Revolver.

Second Lien Term Loan. On April 9, 2009, we also amended and restated our term loan (the "Restated Term Loan") with BNP Paribas, as Administrative Agent, and other lenders and extended its term until October 2, 2012. Borrowings under the Restated Term Loan were initially set at $75.0 million and bear interest at LIBOR plus 8.5% with a LIBOR floor of 3.5%. The Restated Term Loan had an option to increase fixed and floating rate borrowings by up to $25.0 million to $100.0 million prior to May 9, 2009. We exercised this option on April 21, 2009, and the increased borrowings consisted of $5.0 million of floating rate borrowings and $20.0 million of fixed rate borrowings at 13.75%. The loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2009, our asset coverage ratio was 2.7 and the leverage ratio was 1.6. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2009. As of December 31, 2009, we had $80.0 million of variable rate borrowings and $20.0 million of fixed rate borrowings outstanding under the Restated Term Loan. At December 31, 2009, the principal balance of the Restated Term Loan was due and payable on October 2, 2012. We have the right to prepay the Restated Term Loan at any time on or after the first anniversary of the effective date (April 10, 2010), in whole or in part, from April 10, 2010 to April 10, 2011 with a premium equal to 2% of such amount prepaid or subsequent to April 10, 2011 without premium or penalty provided that each prepayment is in an amount that is an integral multiple of $1.0 million and not less than $1.0 million, or if such amount is less than $1.0 million, the outstanding principal amount.

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Working Capital

At December 31, 2009, we had a working capital surplus of $45.7 million as compared to a working capital surplus of $28.6 million at December 31, 2008. Our working capital is affected primarily by fluctuations in the fair value of our commodity derivative instruments, deferred taxes associated with hedging activities, cash and cash equivalents balance and our capital spending program. The surplus for 2009 was largely caused by the increases in our cash balance. As of December 31, 2009, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $61.3 million and $9.0 million, respectively, and there was no balance for current deferred tax assets. In addition, the associated working capital liability balances for accrued liabilities were approximately $37.1 million as of December 31, 2009.

Cash Flows

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows provided by operating activities	$ 160,501	$ 374,719	$ 257,307
Cash flows used in investing activities	(123,865)	(393,070)	(322,041)
Cash flows (used in) provided by financing activities	(18,235)	57,990	5,170
Net increase (decrease) in cash and cash equivalents	$ 18,401	$ 39,639	$ (59,564)

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation and general and administrative expenses. Net cash provided by operating activities continued to be a primary source of liquidity and capital used to finance our capital expenditures for the year ended December 31, 2009.

Cash flows provided by operating activities decreased by $214.2 million for the year ended December 31, 2009 as compared to the same period for 2008. This decrease is largely due to lower oil and natural gas prices and production during 2009 compared to 2008. For the year ended December 31, 2009, we had net losses of $219.2 million with a decrease in production of 6% as compared to the year ended December 31, 2008 with net losses of $188.1 million.

Cash flows provided by operating activities increased by $117.4 million for the year ended December 31, 2008 as compared to the same period for 2007. This increase is largely due to higher oil and natural gas prices during 2008 compared to 2007. For the year ended December 31, 2008, we had net losses of $188.1 million with an increase of production of 17% as compared to the year ended December 31, 2007 with net income of $57.2 million.

Investing Activities. The primary driver of cash used in investing activities is capital spending.

Cash flows used in investing activities decreased by $269.2 million for the year ended December 31, 2009 as compared to the same period for 2008, which primarily reflected reduced expenditures for the acquisition and development of oil and gas properties and drilling. Acquisitions of oil and gas properties decreased $159.3 million and purchases of oil and gas assets decreased $87.4 million from 2008 to 2009 as a result of our decision to exercise prudence and caution with our capital spending in order to preserve our liquidity and maximize our financial position during a period of low commodity prices and reduced demand for natural gas. For the year ended December 31, 2009, we incurred approximately $135.0 million in capital expenditures as compared to $334.4 million for the year ended December 31, 2008. During the year ended December 31, 2009, we participated in the drilling of 43 gross wells as compared to the drilling of 184 gross wells for the year ended December 31, 2008.

Cash flows used in investing activities increased by $71.0 million for the year ended December 31, 2008 as compared to the same period for 2007, which reflected expenditures for the acquisition and development of oil and gas properties and drilling. The Company acquired the Petroflow properties in the San Juan Basin for $29.0 million, the Pinedale and South Texas properties for approximately $55.0 million, and the Calpine non-consent properties as part of the Calpine Settlement for $30.9 million. Additionally, acquisition costs for the year ended December 31, 2008 include a non-cash purchase price adjustment of $36.7 million related to the release of suspended revenues and non-consent liabilities associated with non-consent properties as part of the settlement of litigation with Calpine, as well as an $8.0 million reduction in accrued capital costs. For the year ended December 31, 2008, we incurred approximately $334.4 million in capital expenditures as compared to $336.1 million for the year ended December 31, 2007. During the year ended December 31, 2008, we participated in the drilling of 184 gross wells as compared to the drilling of 195 gross wells for the year ended December 31, 2007.

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Financing Activities. The primary driver of cash used in financing activities is equity transactions and issuance and repayments of debt.

Cash flows provided by financing activities decreased by $76.2 million for the year ended December 31, 2009 as compared to the same period for 2008. The net decrease is primarily related to payments of $40.0 million made in 2009 against the Restated Revolver and $5.9 million of deferred loan fees related to the restated credit facilities netted with $28.4 million of borrowings in 2009 compared to $55.0 million of borrowings in 2008. In addition, there was a decrease of approximately $3.6 million in the stock options exercised for the year ended December 31, 2009 compared to 2008.

Cash flows provided by financing activities increased by $52.8 million for the year ended December 31, 2008 as compared to the same period for 2007. The net increase is primarily related to net borrowings of $55.0 million made in 2008 against the Revolver. In addition, there was an increase of approximately $3.0 million in the stock options exercised for the year ended December 31, 2008 compared to 2007.

Commodity Price Risk, Interest Rate Risk and Related Hedging Activities

The energy markets have historically been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil and natural gas prices from time to time primarily through the use of certain derivative instruments including fixed price swaps, basis swaps, costless collars and put options. Although not risk free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of natural gas fixed-price swaps and costless collars, which are intended to establish a fixed price or an average floor and ceiling price for 13% to 23% of our expected natural gas production through 2011. The fixed-price swap agreements we have entered into require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments.

Borrowings under our Restated Revolver and Restated Term Loan mature on July 1, 2012 and October 2, 2012, respectively, and bear interest at a LIBOR-based rate. This exposes us to risk of earnings loss due to increases in market interest rates. To mitigate this exposure, we have entered into a series of interest rate swap agreements through December 2010. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into additional interest rate swap agreements in the future.

The following table sets forth the results of commodity and interest rate swap hedging transaction settlements:

	For the Year Ended December 31, 2009	2008
Natural Gas		
Quantity settled (MMBtu)	20,856,465	26,684,616
Increase (decrease) in natural gas sales revenue (In thousands)	$ 76,567	$ (18,669)
Interest Rate Swaps		
Increase in interest expense (In thousands)	$ (1,289)	$ (1,158)

In accordance with the authoritative guidance for derivatives, all derivative instruments, not designated as a normal purchase sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions on a quarterly basis, consistent with documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges, if any, are included in other income (expense).

As of December 31, 2009, our commodity and interest rate hedge positions were with counterparties that were also lenders in our credit facilities. This allows us to secure any margin obligation resulting from a negative change in the fair market value of the derivative contracts in connection with our credit obligations and eliminate the need for independent collateral postings. As of December 31, 2009, we had no deposits for collateral.

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Capital Requirements

The historical capital expenditures summary table is included in Items 1 and 2. Business and Properties and is incorporated herein by reference.

Our capital expenditures for the year ended December 31, 2009 were $135.0 million, including capitalized internal costs directly identified with acquisition, exploration and development activities of $4.8 million, capitalized interest of $1.2 million and corporate and other capital costs of $4.1 million. We have plans to carefully execute an organic capital program in 2010 that can be funded from internally generated cash flows and available cash in a $6 per Mcf and a $70 per Bbl price environment. We also have the discretion to use our available borrowing base and proceeds from divestitures to fund capital expenditures, including acquisitions.

Commitments and Contingencies

As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

Contractual Obligations. At December 31, 2009, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

	Payments Due By Period				
	Total	2010	2011 to 2012	2013 to 2014	2015 & Beyond
			(In thousands)		
Senior secured revolving line of credit	$190,000	$-	$190,000	$-	$-
Second lien term loan	100,000	-	100,000	-	-
Operating leases	12,872	3,025	6,204	3,643	-
Interest payments on long-term debt (1)	48,875	18,264	30,611	-	-
Rig commitments	3,542	3,542	-	-	-
Total contractual obligations	$355,289	$24,831	$326,815	$3,643	$-

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2009.

Asset Retirement Obligation. We also had total liabilities of $28.9 million related to asset retirement obligations recorded in Accrued liabilities and Other long-term liabilities at December 31, 2009 that are excluded from the table above. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations. See Item 8. "Financial Statements and Supplementary Data, Note 9 - Asset Retirement Obligation."

Contingencies

We are party to various litigation matters arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters will have a material adverse effect on our financial position, results of operation or cash flows.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, related disclosure of contingent assets and liabilities and proved oil and gas reserves. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8. “Financial Statements and Supplementary Data, Note 2 - Summary of Significant Accounting Policies,” for a discussion of additional accounting policies and estimates made by management.

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Principles of Consolidation

The accompanying consolidated financial statements as of December 31, 2009, 2008 and 2007, contain the accounts of the Company and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are the successful efforts method and the full cost method. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires certain exploration costs to be expensed as they are incurred while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value. The assessment for impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves using a twelve-month average price computed as an average of first day of the month prices, period-end costs and a 10% discount rate. Prior to December 31, 2009, the assessment for impairment under the full cost method required the use of period-end pricing when evaluating the carrying value of oil and gas properties against the net present value of future cash flows from the related proved reserves.

Full Cost Method

We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into a cost center (the amortization base), whether or not the activities to which they apply are successful. As all of our operations are located in the U.S., all of our costs are included in one cost pool. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that directly relate to our oil and gas activities. Interest costs related to unproved properties are also capitalized. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment. Upon evaluation, these costs are transferred to the full cost pool and amortized. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities, since we generally reflect a higher level of capitalized costs as well as a higher DD&A rate on our oil and natural gas properties.

Proved Oil and Gas Reserves

Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently, provided to NSAI who then performs an annual year-end reserve report audit. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impact property, plant and equipment amounts in the consolidated balance sheet and the DD&A amounts in the consolidated statement of operations. Current guidance dictates the use of a twelve-month first day of the month historical average price adjusted for basis and quality differentials for oil and natural gas and holds costs in effect as of the last day of the quarter or annual period constant in calculating reserves. Prior to 2009, the guidance dictated that year-end prices adjusted for basis and quality differentials and costs be used in calculating reserves. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. "Financial Statements and Supplementary Data - Supplemental Oil and Gas Disclosures."

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Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to authoritative guidance, and estimated future income taxes thereon. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and stockholders' equity in the period of occurrence and result in lower DD&A expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The current ceiling calculation utilizes a twelve-month first day of the month historical average price. The costs in effect as of the last day of the quarter or annual period are held constant. Prior to December 31, 2009, ceiling calculation guidance dictated that prices in effect as of the last day of the quarter or annual period be used and allowed a write-down to be reduced or avoided if prices increased subsequent to the end of a quarter but prior to the issuance of our financial statements in which a write-down might otherwise be required. As of December 31, 2009, the use of the recovery of prices after the end of the period is no longer permitted. The full cost ceiling test impairment calculations also take into consideration the effects of hedging contracts that are designated for hedge accounting. Given the fluctuation of natural gas and oil prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If natural gas and oil prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and gas properties could occur in the future. For more information regarding the full cost ceiling limitation, refer to Item 8. "Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies."

Depreciation, Depletion and Amortization

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future depletion expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test write-down. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.09 to $0.10 per Mcfe. This estimated impact is based on current data at December 31, 2009 and actual events could require different adjustments to DD&A.

Costs Withheld From Amortization

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2009, our full cost pool had approximately $42.3 million of costs excluded from the amortization base.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the property’s geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

We provide for future abandonment costs in accordance with authoritative guidance for accounting for asset retirement obligations. This guidance requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

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Derivative Transactions and Hedging Activities

We enter into derivative transactions to hedge against changes in oil and natural gas prices and changes in interest rates related to outstanding debt under our credit agreements primarily through the use of fixed price swap agreements, basis swap agreements, costless collars and put options. Consistent with our hedge policy, we entered into a series of derivative transactions to hedge a portion of our expected natural gas production through 2011. As of December 31, 2009, 13% and 13% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2010 and 5% and 23% of our expected natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2011, based on our annual reserve report. We also entered into a series of interest rate swap agreements to hedge the change in interest rates associated with our variable rate debt through December of 2010. These transactions are recorded in our financial statements in accordance with authoritative guidance for accounting for derivative instruments and hedging activities. Although not risk free, we believe this policy will reduce our exposure to commodity price fluctuations and changes in interest rates and thereby achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with amended guidance, all derivative instruments, unless designated as normal purchase and normal sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flows related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions quarterly, consistent with our documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges are included in Other (income) expense on the Consolidated Statement of Operations.

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board ("FASB") issued authoritative guidance regarding fair value measurements. This guidance defined fair value, established a framework for measuring fair value, expanded the related disclosure requirements and was effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. This guidance did not require any new fair value measurements; however, it did require some entities to change their measurement practices. In February 2008, the FASB issued additional guidance which delayed the effective date of fair value accounting for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Effective January 1, 2008, we implemented the guidance for measuring the fair value of financial assets and liabilities. Beginning January 1, 2009, we implemented the guidance for nonfinancial assets and liabilities. The adoption of this guidance did not have an impact on our consolidated financial position, results of operations or cash flows. In October 2008, the FASB issued guidance on determining the fair value of a financial asset when the market for that asset is not active. This guidance clarifies the application of fair value accounting in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This guidance was effective upon issuance, including prior periods for which financial statements have not been issued. We applied this guidance to financial assets measured at fair value on a recurring basis at September 30, 2009. The adoption of this guidance did not have a significant impact on our consolidated financial position, results of operations or cash flows. In April 2009, the FASB issued authoritative guidance to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. This guidance provides guidelines for making fair value measurements for assets and liabilities for which the volume and level of activity for the asset or liability have significantly decreased or for transactions that are not orderly more consistent with the principles presented in earlier guidance, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, and provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities for other-than-temporary impairments. This guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We applied this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on the Company's consolidated financial position, results of operations or cash flows. See Item 8. "Financial Statements and Supplementary Data, Note 7 - Fair Value Measurements."

Stock-Based Compensation

We account for stock-based compensation in accordance with authoritative guidance regarding the accounting for stock-based compensation. Under the provisions of this guidance, stock-based compensation cost for options is estimated at the grant date based on the award's fair value as calculated by the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period. Stock-based compensation cost for restricted stock is estimated at the grant date based on the award's fair value which is equal to the average high and low common stock price on the date of grant and is recognized as expense over the requisite service period. Stock-based compensation for performance share units ("PSUs") is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions or a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on our estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and historical forfeitures, and the Board's anticipated vesting percentage. Compensation expense for awards with market conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model which incorporates a risk-neutral valuation approach to value these awards. The Monte Carlo model requires various highly judgmental assumptions to determine the fair value of the awards. This model samples paths of ours and the S&P 400 O&G E&P Industry Index (the "Index")'s stock price and calculates the resulting change in cash flow multiple at the end of the forecasted performance period. This model iterates these randomly forecasted results until the distribution of results converge on a mean or estimated fair value. The five primary inputs for the Monte Carlo model are the risk-free rate, independent analyst cash flow per share estimates for the Index and us, volatility of the equities of the Index and us, expected dividends, where applicable, and various historical market data. The risk-free rate was generated from Bloomberg for United States Treasuries with a two-year tenor. Volatility was set equal to the annualized daily volatility measured over a historic 400-day period ending on the reporting date for the Index and us. No forfeiture rate is assumed for this type of award. Expense related to these awards can be volatile based on the Company's comparative performance at the end of each quarter. If any of the assumptions used in the Monte Carlo model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period. See Item 8. "Financial Statements and Supplementary Data, Note 12 – Stock-based Compensation".

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Revenue Recognition

We use the sales method of accounting for the sale of our natural gas. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability.

Since there is a ready market for natural gas, crude oil and natural gas liquids (“NGLs”), we sell our products soon after production at various locations at which time title and risk of loss pass to the buyer. Revenue is recorded when title passes based on our net interest or nominated deliveries of production volumes. We record our share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, NGLs and crude oil are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents once received by us. Historically, these adjustments have been insignificant. In addition, natural gas and crude oil volumes sold are not significantly different from our share of production.

We pay royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Royalties Payable on our Consolidated Balance Sheet.

Income Taxes

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income and change in stockholder ownership that would trigger limits on use of net operating losses under the Internal Revenue Code Section 382. We have a significant deferred tax asset associated with our oil and gas properties. We have concluded that it is more likely than not that we will realize this deferred tax asset in future years and therefore, we have not recorded a valuation allowance as of December 31, 2009. See Item 8. “Financial Statements and Supplementary Data, Note 13 - Income Taxes.”

Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense (benefit) by approximately $3.5 million for the year ended December 31, 2009.

Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

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Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Business Combinations. In December 2007, the FASB revised the authoritative guidance for business combinations, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. The revised guidance broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. The revised guidance also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas purchases. This could cause us to expense transaction costs for future oil and gas property purchases that we have historically capitalized. Additionally, this guidance expands the required disclosures to improve the financial statement users' abilities to evaluate the nature and financial effects of business combinations. This guidance is effective for business combinations for which the acquisition date is on or after January 1, 2009. The adoption of the revised guidance did not have a significant impact on our consolidated financial position, results of operations or cash flows.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the FASB issued authoritative guidance which improves the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance is effective for fiscal years beginning after December 15, 2008. The adoption of this guidance did not have a significant impact on our consolidated financial position, results of operations or cash flows.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued authoritative guidance related to disclosures about derivative instruments and hedging activities, which is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures. This guidance is effective for fiscal years beginning after November 15, 2008. We adopted the disclosure requirements beginning January 1, 2009. See Item 8. "Financial Statements and Supplementary Data, Note 6 - Commodity Hedging Contracts and Other Derivatives."

Fair Value Measurements. In February 2008, the FASB issued authoritative guidance which delayed the effective date of fair value accounting for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Beginning January 1, 2009, we implemented the guidance for nonfinancial assets and liabilities. The adoption of this guidance did not have an impact on our consolidated financial position, results of operations or cash flows. In October 2008, the FASB issued guidance on determining the fair value of a financial asset when the market for that asset is not active. This guidance clarifies the application of fair value accounting in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This guidance was effective upon issuance, including prior periods for which financial statements have not been issued. We applied this guidance to financial assets measured at fair value on a recurring basis at September 30, 2009. See Item 8. "Financial Statements and Supplementary Data, Note 5 - Fair Value Measurements." The adoption of this guidance did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In April 2009, the FASB issued authoritative guidance to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. This guidance provides guidelines for making fair value measurements for assets and liabilities for which the volume and level of activity for the asset or liability have significantly decreased or for transactions that are not orderly more consistent with the principles presented in earlier guidance, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, and provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities for other-than-temporary impairments. This guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We applied this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures will be required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. This guidance will require additional disclosures but will not impact our consolidated financial position, results of operations or cash flows.

Subsequent Events. In May 2009, the FASB issued authoritative guidance on subsequent events to incorporate accounting guidance that originated as auditing standards into the body of authoritative literature issued by the FASB. This guidance requires the evaluation of subsequent events through the date the financial statements are issued or are available for issue and the disclosure of the date through which subsequent events were evaluated and the basis for that date. This guidance is effective for interim and annual financial periods ending after June 15, 2009. We adopted the requirements of this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on our consolidated financial position, results of operations or cash flows. On February 25, 2010, the FASB amended this guidance to remove the requirement to disclose the date through which an entity has evaluated subsequent events. See Item 8. “Financial Statements and Supplementary Data, Note 16 – Subsequent Events.”

Variable Interest Entities. In June 2009, the FASB issued authoritative guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities will be effective on January 1, 2010 and will not have an impact on our consolidated financial position, results of operations or cash flows.

FASB Codification. In July 2009, the FASB issued guidance making the FASB Accounting Standards Codification the single source of authoritative nongovernmental U.S. GAAP. The Codification is not intended to change GAAP, however, it will represent a significant change in researching issues and referencing U.S. GAAP in financial statements and accounting policies. This guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We applied this guidance as of the period ended September 30, 2009.

Oil and Gas Reporting Requirements. In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting" (the "Release"). The disclosure requirements under this Release require reporting of oil and gas reserves using an average price based upon the prior twelve-month period rather than year-end prices and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies will also be allowed, but not required, to disclose probable and possible reserves in SEC filings. In addition, companies will be required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The new disclosure requirements become effective beginning with our annual report on Form 10-K for the year ending December 31, 2009. In October 2009, the SEC issued Staff Accounting Bulletin ("SAB") No. 113 to bring existing SEC guidance into conformity with the Release. The principle revisions of the guidance include changing the price used in determining quantities of oil and gas reserves, as noted above; eliminating the option to use post-quarter-end prices to evaluate write-offs of excess capitalized costs under the full cost method of accounting; removing the exclusion of unconventional methods used in extracting oil and gas from oil sands or shale as an oil and gas producing activity; and removing certain questions and interpretative guidance which are no longer necessary. In January 2010, the FASB issued its guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC's final rule. The Company applied this guidance at December 31, 2009 as a change in accounting principle that is inseparable from a change in accounting estimate. This methodology was different than that applied at December 31, 2008 and March 31, 2009, each of which resulted in a ceiling test write-down. The effect of the adoption at December 31, 2009 was not significant to our financial statements. The adoption of the new rule will result in future amounts recorded for depreciation, depletion and amortization and ceiling limitations being different from what would have been recorded if the new rules would not have been mandated. See Item 8. "Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures."

Off-Balance Sheet Arrangements

At December 31, 2009 and 2008, we did not have any off-balance sheet arrangements.

Forward-Looking Statements

This report includes forward-looking information regarding Rosetta that is intended to be covered by the "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations for the future, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management’s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. “Risk Factors” in Part I. of this report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances, or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

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- the supply and demand for natural gas and oil;
- the price of oil and natural gas;
- general economic conditions, either internationally, nationally or in jurisdictions affecting our business;
- conditions in the energy and economic markets;
- our ability to access the capital markets on favorable terms or at all;
- our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;
- the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the occurrence of property acquisitions or divestitures;
- reserve levels;
- inflation;
- competition in the oil and natural gas industry;
- the availability and cost of relevant raw materials, goods and services;
- the availability and cost of processing and transportation;
- changes or advances in technology;
- potential reserve revisions;
- future processing volumes and pipeline throughput;
- developments in oil-producing and natural gas-producing countries;
- drilling and exploration risks;
- several possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
- effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
- present and possible future claims, litigation and enforcement actions;

– lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;

– the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business; and

– any other factors that impact or could impact the exploration of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers 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 reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Commodity Price Risk, Interest Rate Risk and Related Hedging Activities.”

Commodity Price Risk. Our major market risk exposure is in the pricing of our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

Our fixed-price swap agreements are used to fix the sales price for our anticipated future oil and natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. We have designated these swaps as cash flow hedges.

We use derivative transactions to manage exposure to changes in commodity prices and interest rates. Our objective for holding derivative instruments is to achieve a consistent level of cash flow to support a portion of our planned capital spending. Our use of derivative transactions for hedging activities could materially affect our results of operations, in particular quarterly or annual periods since such instruments can limit our ability to benefit from favorable interest rate movements. We do not enter into derivative instruments for speculative purposes.

We believe the use of derivative transactions, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and interest rates and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production or variable rate debt and thus provide only partial price protection against declines in commodity prices or rising interest rates. We expect that the amount of our derivative contracts will vary from time to time.

On December 31, 2009, we had open natural gas derivative hedges in an asset position with a fair value of $7.4 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $10.3 million, while a 10 percent decrease in natural gas prices would increase the fair value by approximately $10.5 million. The effects of these derivative transactions on our natural gas sales are discussed above under “Results of Operations – Natural Gas”. These fair value changes assume volatility based on prevailing market parameters at December 31, 2009. In addition, the majority of our capital expenditures is discretionary and could be curtailed if our cash flows decline from expected levels.

Our current cash flow hedge positions are with counterparties who are lenders in our credit facilities. Based upon communications with these counterparties, we expect the obligations under these transactions to continue to be met. We evaluated nonperformance risk using current credit default swap values and default probabilities for each counterparty and recorded a downward adjustment to the fair value of our derivative assets in the amount of $0.01 million at December 31, 2009. We currently know of no circumstances that would limit access to our credit facility or require a change in our debt or hedging structure.

At December 31, 2009, we had the following financial fixed price swap and costless collar positions outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Natural Gas Production Hedged (1)	Fair Market Value Asset/(Liability) (In thousands)
2010	Swap	Cash flow	15,000	5,475,000	$ 7.46	$ -	13 %	$ 8,834
2010	Costless Collar	Cash flow	15,041	5,490,000	5.75	7.40	13 %	548
2011	Swap	Cash flow	5,000	1,825,000	5.72		5 %	(408)
2011	Costless Collar	Cash flow	25,000	9,125,000	5.80	7.58	23 %	(1,552)
				21,915,000				$ 7,422

(1) Estimated based on anticipated future gas production.

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In January 2010, we entered into additional costless collar transactions to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2012. The costless collars have a floor price of $5.75 per MMBtu and a ceiling price of $6.50 per MMBtu through 2011 and $7.15 per MMBtu in 2012. In February 2010, we entered into natural gas fixed-price swaps to hedge 10,000 MMBtu/d of our expected production for July 2010 through December 2011 at an average price of $5.91 per MMBtu.

Interest Rate Risks. We have entered into a series of fixed rate swap agreements for a portion of our variable rate debt. Our fixed-rate swap agreements are used to fix the interest rate we pay under our variable rate credit facilities. The fixed-rate swaps are freestanding financial agreements that require us and the counterparty to net cash settle our gains and losses on a monthly basis. Upon settlement, we receive a floating market LIBOR rate and pay our counterparty a fixed interest rate, as defined in each instrument. When the floating rate exceeds the fixed rate for a contract month, our counterparty pays us. When the fixed price exceeds the floating price, we are required to make a payment to our counterparty. We have designated these swaps as cash flow hedges. At December 31, 2009, we had open interest rate swap hedges in a liability position of $0.6 million. A 10 percent increase in interest rates would increase the fair value by approximately $0.06 million, while a 10 percent decrease in interest rates would decrease the fair value by approximately $0.06 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2009.

We have hedged the interest rates on $100.0 million of our variable rate debt through December 31, 2010. At December 31, 2009 we had the following financial fixed interest rate swap positions outstanding:

Settlement Period	Derivative Instrument	Hedge Strategy	Average Fixed Rate		Fair Market Value Asset/(Liability) (In thousands)	
January 1 - December 31, 2010	Swap	Cash Flow	1.24	%	$	(635	)

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Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of Rosetta Resources Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows and of stockholders' equity present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries (the "Company") at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2, at December 31, 2009 the Company changed the manner in which its oil and gas reserves are estimated as well as the manner in which prices are determined to calculate the ceiling limit on capitalized oil and gas costs.

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

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

/s/ PricewaterhouseCoopers LLP

February 26, 2010
Houston, Texas

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Item 8. Financial Statements and Supplementary Data

Rosetta Resources Inc.
Consolidated Balance Sheet
(In thousands, except share amounts)

	December 31, 2009	2008
Assets		
Current assets:		
Cash and cash equivalents	$61,256	$42,855
Restricted cash	-	1,421
Accounts receivable	32,691	41,885
Derivative instruments	8,983	34,742
Prepaid expenses	2,837	5,046
Other current assets	6,415	4,071
Total current assets	112,182	130,020
Oil and natural gas properties, full cost method, of which $42.3 million at December 31, 2009 and $50.3 million at December 31, 2008 were excluded from amortization	2,030,433	1,900,672
Other fixed assets	12,417	9,439
	2,042,850	1,910,111
Accumulated depreciation, depletion, and amortization, including impairment	(1,452,248)	(935,851)
Total property and equipment, net	590,602	974,260
Deferred loan fees	4,921	1,168
Deferred tax asset	169,732	42,652
Other assets	2,147	6,278
Total other assets	176,800	50,098
Total assets	$879,584	$1,154,378
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$2,279	$2,268
Accrued liabilities	37,107	48,824
Royalties payable	16,064	17,388
Derivative instruments	236	985
Prepayment on gas sales	7,542	19,382
Deferred income taxes	3,258	12,575
Total current liabilities	66,486	101,422
Long-term liabilities:		
Derivative instruments	1,960	-
Long-term debt	288,742	300,000
Other long-term liabilities	29,301	26,584
Total liabilities	$386,489	$428,006
Commitments and contingencies (Note 11)		
Stockholders' equity:		
	-	-

Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2009 or 2008		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 51,254,709 shares and 51,031,481 shares at December 31, 2009 and 2008, respectively	51	51
Additional paid-in capital	780,196	773,676
Treasury stock, at cost; 199,955 and 155,790 shares at December 31, 2009 and 2008, respectively	(3,473)	(2,672)
Accumulated other comprehensive income	4,259	24,079
Accumulated deficit	(287,938)	(68,762)
Total stockholders' equity	493,095	726,372
Total liabilities and stockholders' equity	$879,584	$1,154,378

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.
Consolidated Statement of Operations
(In thousands, except per share amounts)

	Year Ended December 31, 2009	2008	2007
Revenues:			
Natural gas sales	$250,684	$398,268	$295,644
Oil sales	21,763	55,736	40,148
NGL sales	21,504	45,343	27,697
Total revenues	293,951	499,347	363,489
Operating costs and expenses:			
Lease operating expense	60,773	55,694	47,044
Depreciation, depletion, and amortization	121,042	198,862	152,882
Impairment of oil and gas properties	379,462	444,369	-
Treating and transportation	5,675	6,323	4,230
Marketing fees	593	3,064	2,450
Production taxes	6,131	13,528	6,417
General and administrative costs	46,993	52,846	43,867
Total operating costs and expenses	620,669	774,686	256,890
Operating income (loss)	(326,718)	(275,339)	106,599
Other (income) expense:			
Interest expense, net of interest capitalized	19,258	14,688	17,734
Interest income	(97)	(1,600)	(1,674)
Other (income) expense, net	(876)	12,510	(698)
Total other expense	18,285	25,598	15,362
Income (loss) before provision for income taxes	(345,003)	(300,937)	91,237
Income tax expense (benefit)	(125,827)	(112,827)	34,032
Net income (loss)	$(219,176)	$(188,110)	$57,205
Earnings (loss) per share:			
Basic	$(4.30)	$(3.71)	$1.14
Diluted	$(4.30)	$(3.71)	$1.13
Weighted average shares outstanding:			
Basic	50,979	50,693	50,379
Diluted	50,979	50,693	50,589

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.
Consolidated Statement of Cash Flows
(In thousands)

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities			
Net income (loss)	$(219,176)	$(188,110)	$57,205
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	121,042	198,862	152,882
Impairment of oil and gas properties	379,462	444,369	-
Deferred income taxes	(124,632)	(116,519)	33,915
Amortization of deferred loan fees recorded as interest expense	2,102	1,027	1,180
Amortization of original issue discount recorded as interest expense	342	-	-
Stock compensation expense	7,836	7,234	6,831
Other non-cash items	-	(512)	(181)
Change in operating assets and liabilities:			
Accounts receivable	9,194	13,163	(18,640)
Income taxes receivable	-	(776)	-
Prepaid expenses	2,209	5,367	(1,652)
Other current assets	(2,344)	178	(1,284)
Other assets	(484)	191	144
Accounts payable	11	5,031	10,909
Accrued liabilities	(1,897)	7,322	3,998
Royalties payable	(13,164)	(2,108)	12,000
Net cash provided by operating activities	160,501	374,719	257,307
Cash flows from investing activities			
Acquisition of oil and gas properties	(3,844)	(163,187)	(38,656)
Purchases of oil and gas assets	(141,016)	(228,464)	(284,541)
Disposals of oil and gas properties and assets	19,574	-	-
(Increase) decrease in restricted cash	1,421	(1,421)	-
Other	-	2	1,156
Net cash used in investing activities	(123,865)	(393,070)	(322,041)
Cash flows from financing activities			
Borrowings on revolving credit facility	28,400	55,000	10,000
Payments on revolving credit facility	(40,000)	-	(5,000)
Deferred loan fees	(5,855)	-	-
Proceeds from stock options exercised	21	3,617	653
Purchases of treasury stock	(801)	(627)	(483)
Net cash (used in) provided by financing activities	(18,235)	57,990	5,170
Net increase (decrease) in cash	18,401	39,639	(59,564)
Cash and cash equivalents, beginning of year	42,855	3,216	62,780
Cash and cash equivalents, end of year	$61,256	$42,855	$3,216
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$16,813	$13,658	$18,862
Cash (received) paid for tax	$(1,196)	$4,470	$115

Supplemental non-cash disclosures:			
Capital expenditures included in accrued liabilities	$18,199	$26,555	$34,599
Release of suspended revenues and non-consent liabilities resulting from Calpine Settlement included in Accounts payable and Acquisition of oil and gas properties	$-	$36,713	$-

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.
Consolidated Statement of Stockholders' Equity
(In thousands, except share amounts)

	Common Stock		Additional Paid-In	Treasury Stock		Accumulated Other Comprehensive	Retained Earnings / Accumulated	Total Stockholders'
	Shares	Amount	Capital	Share	Amount	(Loss)/Income	Deficit	Equity
Balance at December 31, 2006	50,405,794	$50	$755,343	85,788	$(1,562)	$ 6,315	$ 62,143	$ 822,289
Stock options exercised	40,104	-	653	-	-	-	-	653
Treasury stock - employee tax payment	-	-	-	23,515	(483)	-	-	(483)
Stock-based compensation	-	-	6,831	-	-	-	-	6,831
Vesting of restricted stock	96,750	-	-	-	-	-	-	-
Comprehensive income:	-	-	-	-	-	-	-	-
Net income	-	-	-	-	-	-	57,205	57,205
Change in fair value of derivative hedging instruments	-	-	-	-	-	1,276	-	1,276
Hedge settlements reclassified to income	-	-	-	-	-	(22,926)	-	(22,926)
Tax benefit related to cash flow hedges	-	-	-	-	-	8,110	-	8,110
Comprehensive income	-	-	-	-	-	-	-	43,665
Balance at December 31, 2007	50,542,648	$50	$762,827	109,303	$(2,045)	$ (7,225)	$ 119,348	$ 872,955
Stock options exercised	214,119	1	3,615	-	-	-	-	3,616
Treasury stock - employee tax payment	-	-	-	46,487	(627)	-	-	(627)
Stock-based compensation	-	-	7,234	-	-	-	-	7,234
Vesting of restricted stock	274,714	-	-	-	-	-	-	-
Comprehensive loss:	-	-	-	-	-	-	-	-

Net loss	-	-	-	-	-	-	(188,110)	(188,110)
Change in fair value of derivative hedging instruments	-	-	-	-	-	30,057	-	30,057
Hedge settlements reclassified to income	-	-	-	-	-	19,829	-	19,829
Tax expense related to cash flow hedges	-	-	-	-	-	(18,582)	-	(18,582)
Comprehensive loss	-	-	-	-	-	-	-	(156,806)
Balance at December 31, 2008	51,031,481	$51	$773,676	155,790	$(2,672)	$ 24,079	$ (68,762)	$ 726,372
Stock options exercised	14,125	-	21	-	-	-	-	21
Treasury stock - employee tax payment	-	-	-	44,165	(801)	-	-	(801)
Stock-based compensation	-	-	6,499	-	-	-	-	6,499
Vesting of restricted stock	209,103	-	-	-	-	-	-	-
Comprehensive loss:	-	-	-	-	-	-	-	-
Net loss	-	-	-	-	-	-	(219,176)	(219,176)
Change in fair value of derivative hedging instruments	-	-	-	-	-	43,693	-	43,693
Hedge settlements reclassified to income	-	-	-	-	-	(75,278)	-	(75,278)
Tax expense related to cash flow hedges	-	-	-	-	-	11,765	-	11,765
Comprehensive loss	-	-	-	-	-	-	-	(238,996)
Balance at December 31, 2009	51,254,709	$51	$780,196	199,955	$(3,473)	$ 4,259	$ (287,938)	$ 493,095

The accompanying notes to the financial statements are an integral part hereof.

Rosetta Resources Inc.

Notes to Consolidated Financial Statements

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the "Company") is an independent oil and gas company that is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States. The Company's main operations are primarily concentrated in the Sacramento Basin of California, the Rockies, the Lobo and Perdido Trends in South Texas, the State Waters of Texas and the Gulf of Mexico.

In preparing these financial statements, the Company has evaluated events and transactions for potential recognition or disclosure through February 26, 2010, the date the financial statements were issued. See Item 8. "Financial Statements and Supplementary Data, Note 16 – Subsequent Events."

Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income (loss).

(2) Summary of Significant Accounting Policies

Change in accounting principle

As more fully described below in Property Plant and Equipment, net and Supplemental Oil and Gas Disclosures within these consolidated financial statements, in January 2010 the FASB issued Accounting Standards Update 2010-03, "Extractive Activities -- Oil and Gas", which conforms the authoritative guidance to the requirements of the new SEC rules released in December 2008 "Modernization of Oil and Gas Reporting" and are effective December 31, 2009. The principle revisions under the new authoritative guidance include changing the manner in which oil and gas reserves are estimated as well as the manner in which prices are determined to calculate the ceiling limit on capitalized oil and gas costs. This change in accounting has been treated in these financial statements as a change in accounting principle that is inseparable from a change in accounting estimate.

The effect of the adoption at December 31, 2009 was not significant to the Company's financial statements. The adoption of the new rule will result in future amounts recorded for depreciation, depletion and amortization and ceiling limitations being different from what would have been recorded if the new rules would not have been mandated.

FASB Codification

In July 2009, the FASB issued guidance making the FASB Accounting Standards Codification the single source of authoritative nongovernmental U.S. GAAP. The Codification is not intended to change GAAP, however, it will represent a significant change in researching issues and referencing U.S. GAAP in financial statements and accounting policies. This guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company applied this guidance as of the period ended September 30, 2009.

Principles of Consolidation and Basis of Presentation

The accompanying consolidated financial statements for the years ended December 31, 2009, 2008 and 2007 contain the accounts of Rosetta Resources Inc. and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

Use of Estimates in Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates their estimates and assumptions on a regular basis. The Company bases their estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the Company’s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, the outcome of pending litigation, stock-based compensation, valuation of derivative instruments, future development and abandonment costs, estimates to certain oil and gas revenues and expenses and estimates of proved oil and natural gas reserve quantities used to calculate depletion, depreciation and impairment of proved oil and natural gas properties and equipment.

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Cash and Cash Equivalents

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

With respect to the current market environment for liquidity and access to credit, the Company, through banks participating in its credit facility, has invested available cash in interest and non-interest bearing demand deposit accounts in those participating banks and in money market accounts and funds whose investments are limited to United States Government Securities, securities backed by the United States Government, or securities of United States Government agencies. The Company has followed this policy and believes this is an appropriate approach for the investment of Company funds.

Restricted Cash

At December 31, 2009, the Company had no restricted cash. Restricted cash of $1.4 million at December 31, 2008 consisted of cash deposited by the Company in an escrow account, which was created in conjunction with the South Texas acquisitions for potential environmental remediation costs associated with acquired properties.

Allowance for Doubtful Accounts

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances.

Property, Plant and Equipment, Net

The Company follows the full cost method of accounting for oil and natural gas properties. Under the full cost method, all costs incurred in acquiring, exploring and developing properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized when incurred into cost centers that are established on a country-by-country basis, and are amortized as reserves in the cost center in which they are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with offshore U.S. operations, unevaluated properties and significant development projects are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of whatever reserves ultimately result from the efforts as a whole, and are thus associated with the Company’s reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $4.8 million, $7.1 million and $5.5 million of internal costs for the years ended December 31, 2009, 2008 and 2007, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment at which time they are transferred to the full cost pool to be amortized. Upon evaluation, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally included in the full cost pool unless a significant portion of the pool or reserves are sold.

The Company assesses the impairment for oil and natural gas properties quarterly using a ceiling test to determine if impairment is necessary. This ceiling limits capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to authoritative guidance, and estimated future income taxes thereon. Prior to December 31, 2009, the ceiling calculation dictated that prices and costs in effect as of the last day of the quarter be held constant. The current ceiling calculation utilizes prices calculated as a twelve-month average price using first day of the month prices and costs in effect as of the last day of the quarter are held constant. Prior to December 31, 2009, for periods in which a write-down was required, if oil and gas prices increased subsequent to the end of a quarter or annual period but prior to the issuance of the financial statements, the Company was allowed to adjust the write-down to reflect the higher prices. As of December 31, 2009, the use of the recovery of prices after the end of the period is no longer permitted. A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, it would reduce earnings and impact shareholders' equity in the period of occurrence and result in lower DD&A expense in the future. The average rates of DD&A were $2.39, $3.71 and $3.34 per Mcfe in 2009, 2008 and 2007, respectively.

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The table below sets forth relevant assumptions utilized in the quarterly ceiling test computations for the respective periods noted:

	Total Impairment	2009 December 31(3)	September 30(1)	June 30	March 31
Henry Hub natural gas price (per MMBtu)(4)		$3.87	$4.59	$3.89	$3.63
West Texas Intermediate oil price (per Bbl)(4)		57.65	76.25	66.25	46.00
Increase (decrease) of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		45,000	29,334	55,299	79,664
Impairment recorded (pre-tax) (in thousands)	$379,462	-	-	-	379,462
Potential impairment absent the effects of hedging (pre-tax) (in thousands) (5)		29,482	-	26,337	459,126

	Total Impairment	2008 December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(4)		$5.71	$7.12	$13.10	$9.37
West Texas Intermediate oil price (per Bbl)(4)		41.00	96.37	140.22	105.63
Increase (decrease) of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		47,142	37,440	(141,123)	(60,043)
Impairment recorded (pre-tax) (in thousands)	$444,369	238,710	205,659	-	-
Potential impairment absent the effects of hedging (pre-tax) (in thousands) (5)		285,852	243,099	-	-

	Total Impairment	2007 December 31(2)	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(4)		$8.91	$6.38	$6.80	$7.34
West Texas Intermediate oil price (per Bbl)(4)		98.88	82.88	69.63	66.20
Increase (decrease) of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		(34,616)	46,056	34,582	23,904
Impairment recorded (pre-tax) (in thousands)	$-	-	-	-	-
Potential impairment absent the effects of hedging (pre-tax) (in thousands) (5)		-	31,657	-	-

(1) The Company’s ceiling test was calculated using hedge adjusted market prices of gas and oil at September 30, 2009, which were based on a Henry Hub price of $3.30 per MMBtu and a West Texas Intermediate oil price of $67.00 per Bbl (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at September 30, 2009 increased the calculated ceiling value by approximately $50.7 million (pre-tax). The use of these prices would have resulted in a pre-tax write-down of $18.8 million at September 30, 2009. As allowed under the full cost accounting rules at the time, the Company re-evaluated the ceiling test on October 29, 2009 using the market price for Henry Hub of $4.59 per MMBtu and West Texas Intermediate oil price of $76.25 per Bbl (adjusted for basis and quality differentials). At these prices, cash flow hedges of natural gas production in place increased the calculated ceiling value by approximately $29.3 million (pre-tax). Utilizing these prices, the calculated ceiling amount exceeded the Company’s net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the quarter ended September 30, 2009.

(2) The Company’s ceiling test was calculated using hedge adjusted market prices of gas and oil at December 31, 2007, which were based on a Henry Hub price of $6.80 per MMBtu and a West Texas Intermediate oil price of $92.50 per Bbl (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at December 31, 2007 increased the calculated ceiling value by approximately $32.1 million (pre-tax). The use of these prices would have resulted in a pre-tax write-down of $21.5 million at December 31, 2007. As allowed under the full cost accounting rules at the time, the Company re-evaluated the ceiling test on February 22, 2008 using the market price for Henry Hub of $8.91 per MMBtu and West Texas Intermediate oil price of $98.88 per Bbl (adjusted for basis and quality differentials). At these prices, cash flow hedges of natural gas production in place decreased the calculated ceiling value by approximately $34.6 million (pre-tax). Utilizing these prices, the calculated ceiling amount exceeded the Company’s net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the quarter ended December 31, 2007.

(3) The December 31, 2009 oil and natural gas prices are calculated as a twelve-month historical average of the first day of the month prices for the West Texas Intermediate oil price and the Henry Hub natural gas price.

(4) Adjusted for basis and quality differentials.

(5) Represents the total potential impairment excluding the effects of hedging. Where there is no potential impairment for the period, the Company was able to utilize higher prices subsequent to period end and there would have been no impairment recognized with or without the effects of hedging.

Due to the volatility of commodity prices, should oil and natural gas prices decline in the future, we experience a significant downward adjustment to our estimated proved reserves, and/or our commodity hedges settle and are not replaced, it is possible that another write-down of our oil and gas properties could occur.

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Other property, plant and equipment primarily includes furniture, fixtures and automobiles, which are recorded at cost and depreciated on a straight-line basis over useful lives of five to seven years. Repair and maintenance costs are charged to expense as incurred while renewals and betterments are capitalized as additions to the related assets in the period incurred. Gains or losses from the disposal of property, plant and equipment are recorded in the period incurred. The net book value of the property, plant and equipment that is retired or sold is charged to accumulated depreciation, asset cost and amortization, and the difference is recognized as a gain or loss in the results of operations in the period the retirement or sale transpires.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment, and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

We provide for future abandonment costs in accordance with authoritative guidance regarding the accounting for asset retirement obligations. This guidance requires that a liability for the fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Capitalized Interest

The Company capitalizes interest on capital invested in projects related to unevaluated properties and significant development projects in accordance with authoritative guidance for the capitalization of interest cost. As proved reserves are established or impairment determined, the related capitalized interest is included in costs subject to amortization.

Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, other current assets and current liabilities reported in the consolidated balance sheet approximate fair value because of their short-term nature. Derivatives are also recorded on the balance sheet at fair value. The carrying amount of long-term debt reported in the consolidated balance sheet at December 31, 2009 is $288.7 million. The Company calculated the fair value of its long-term debt as of December 31, 2009 in accordance with the authoritative guidance for fair value measurements using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality, and risk profile. Based on this calculation, the Company has determined the fair market value of its debt to be $303.0 million at December 31, 2009. The fair market value of debt at December 31, 2008 was $275.0 million.

Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of cash, accounts receivable and derivative instruments. The Company’s accounts receivable and derivative instruments are concentrated among entities engaged in the energy industry within the United States and financial institutions, respectively.

Deferred Loan Fees

Loan fees incurred in connection with the credit facility are recorded on the Company's Consolidated Balance Sheet as deferred loan fees. The deferred loan fees are amortized to interest expense over the term of the related debt using the straight-line method, which approximates the effective interest method.

Derivative Instruments and Hedging Activities

The Company uses derivative instruments to manage market risks resulting from fluctuations in commodity prices of natural gas and crude oil. The Company also uses derivatives to manage interest rate risk associated with its debt under its credit facility. The Company periodically enters into derivative contracts, including price swaps or costless price collars, which may require payments to (or receipts from) counterparties based on the differential between a fixed price or interest rate and a variable price or LIBOR rate for a fixed notional quantity or amount without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments or debt under its current credit agreements.

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Derivatives are recorded on the balance sheet at fair market value and changes in the fair market value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated and qualifies as a hedge. The Company's derivatives consist of cash flow hedges in which the Company is hedging the variability of cash flows related to a forecasted transaction. Changes in the fair market value of these derivative instruments designated as cash flow hedges are reported in accumulated other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedge is recognized in current period earnings as other income (expense). Gains and losses on derivative instruments that do not qualify for hedge accounting are included in revenue in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities.

At the inception of a derivative contract, the Company may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documents the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item and gains and losses are recognized in income. Gains and losses included in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If the Company determines it is not probable that a forecasted transaction will occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately. The Company does not enter into derivative agreements for trading or other speculative purposes. See Item 8. "Financial Statements and Supplementary Data, Note 6 – Commodity Hedging Contracts and Other Derivatives" for a description of the derivative contracts which the Company executes.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. There were no significant environmental liabilities at December 31, 2009 or 2008.

Stock-Based Compensation

Stock-based compensation cost for options is estimated at the grant date based on the award's fair value as calculated by the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period. Stock-based compensation cost for restricted stock is estimated at the grant date based on the award's fair value which is equal to the average high and low common stock price on the date of grant and is recognized as expense over the requisite service period.

Stock-based compensation for PSUs is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions or a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and historical forfeitures, and the Board's anticipated vesting percentage. Compensation expense for awards with market conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model. The Monte Carlo model requires various highly judgmental assumptions including volatility and future cash flow projections. If any of the assumptions used in the Monte Carlo model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

Any excess tax benefit arising from our deferred compensation plans is recognized as a credit to additional paid in capital when realized and is calculated as the amount by which the tax deduction received exceeds the deferred tax asset associated with the recorded stock compensation expense. The Company has approximately $0.3 million of related excess tax benefits which will be recognized upon utilization of our net operating loss carryforward. Current authoritative guidance requires the cash flows that result from tax deductions in excess of the compensation expense to be recognized as financing activities.

Preferred Stock

The Company is authorized to issue 5,000,000 shares of preferred stock with preferences and rights as determined by the Company's Board of Directors. As of December 31, 2009 and 2008, there were no shares of preferred stock outstanding.

Treasury Stock

Shares of common stock were repurchased by the Company as the shares were surrendered by the employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of the Company's common stock, nor does the Company have a publicly announced program to repurchase shares of common stock.

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Revenue Recognition

The Company uses the sales method of accounting for the sale of its natural gas. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At December 31, 2009 and 2008, imbalances were insignificant.

Since there is a ready market for natural gas, crude oil and NGLs, the Company sells its products soon after production at various locations at which time title and risk of loss pass to the buyer. Revenue is recorded when title passes based on the Company's net interest or nominated deliveries of production volumes. The Company records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, NGLs and crude oil are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents once received by the Company. Historically, these adjustments have been insignificant. In addition, natural gas and crude oil volumes sold are not significantly different from the Company's share of production.

The Company calculates and pays royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Royalties Payable on the Company's Consolidated Balance Sheet.

Income Taxes

Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities using the liability method in accordance with the provisions set forth in the authoritative guidance regarding the accounting for income taxes. Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Authoritative guidance for accounting for uncertainty in income taxes requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Business Combinations. In December 2007, the FASB revised the authoritative guidance for business combinations, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. The revised guidance broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. The revised guidance also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas purchases. This could cause the Company to expense transaction costs for future oil and gas property purchases that we have historically capitalized. Additionally, this guidance expands the required disclosures to improve the financial statement users' abilities to evaluate the nature and financial effects of business combinations. This guidance is effective for business combinations for which the acquisition date is on or after January 1, 2009. The adoption of the revised guidance did not have a significant impact on the Company's consolidated financial position, results of operations or cash flows.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the FASB issued authoritative guidance which improves the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance is effective for fiscal years beginning after December 15, 2008. The adoption of this guidance did not have a significant impact on the Company's consolidated financial position, results of operations or cash flows.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued authoritative guidance related to disclosures about derivative instruments and hedging activities, which is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures. This guidance is effective for fiscal years beginning after November 15, 2008. The Company adopted the disclosure requirements beginning January 1, 2009. See Item 8. "Financial Statements and Supplementary Data, Note 6 - Commodity Hedging Contracts and Other Derivatives."

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Fair Value Measurements. In February 2008, the FASB issued authoritative guidance which delayed the effective date of fair value accounting for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. Beginning January 1, 2009, the Company implemented the guidance for nonfinancial assets and liabilities. The adoption of this guidance did not have an impact on the Company’s consolidated financial position, results of operations or cash flows. In October 2008, the FASB issued guidance on determining the fair value of a financial asset when the market for that asset is not active. This guidance clarifies the application of fair value accounting in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This guidance was effective upon issuance, including prior periods for which financial statements have not been issued. The Company applied this guidance to financial assets measured at fair value on a recurring basis at September 30, 2009. See Item 8. “Financial Statements and Supplementary Data, Note 5 - Fair Value Measurements.” The adoption of this guidance did not have a significant impact on the Company’s consolidated financial position, results of operations or cash flows.

In April 2009, the FASB issued authoritative guidance to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. This guidance provides guidelines for making fair value measurements for assets and liabilities for which the volume and level of activity for the asset or liability have significantly decreased or for transactions that are not orderly more consistent with the principles presented in earlier guidance, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, and provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities for other-than-temporary impairments. This guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company applied this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on the Company’s consolidated financial position, results of operations or cash flows.

In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures will be required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. This guidance will require additional disclosures but will not impact the Company’s consolidated financial position, results of operations or cash flows.

Subsequent Events. In May 2009, the FASB issued authoritative guidance on subsequent events to incorporate accounting guidance that originated as auditing standards into the body of authoritative literature issued by the FASB. This guidance requires the evaluation of subsequent events through the date the financial statements are issued or are available for issue and the disclosure of the date through which subsequent events were evaluated and the basis for that date. This guidance is effective for interim and annual financial periods ending after June 15, 2009. The Company adopted the requirements of this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on our consolidated financial position, results of operations or cash flows. On February 25, 2010, the FASB amended this guidance to remove the requirement to disclose the date through which an entity has evaluated subsequent events. See Item 8. “Financial Statements and Supplementary Data, Note 16 – Subsequent Events.”

Variable Interest Entities. In June 2009, the FASB issued authoritative guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities will be effective on January 1, 2010 and will not have an impact on the Company's consolidated financial position, results of operations or cash flows.

Oil and Gas Reporting Requirements. In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting" (the "Release"). The disclosure requirements under this Release require reporting of oil and gas reserves using an average price based upon the prior twelve-month period rather than year-end prices and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies will also be allowed, but not required, to disclose probable and possible reserves in SEC filings. In addition, companies will be required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The new disclosure requirements become effective for the Company beginning with our annual report on Form 10-K for the year ending December 31, 2009. In October 2009, the SEC issued Staff Accounting Bulletin ("SAB") No. 113 to bring existing SEC guidance into conformity with the Release. The principle revisions of the guidance include changing the price used in determining quantities of oil and gas reserves, as noted above; eliminating the option to use post-quarter-end prices to evaluate write-offs of excess capitalized costs under the full cost method of accounting; removing the exclusion of unconventional methods used in extracting oil and gas from oil sands or shale as an oil and gas producing activity; and removing certain questions and interpretative guidance which are no longer necessary. In January 2010, the FASB issued its guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC's final rule. The Company applied this guidance at December 31, 2009 as a change in accounting principle that is inseparable from a change in accounting estimate. This methodology was different than that applied at December 31, 2008 and March 31, 2009, each of which resulted in a ceiling test write-down. The effect of the adoption at December 31, 2009 was not significant to the Company's financial statements. The adoption of the new rule will result in future amounts recorded for depreciation, depletion and amortization and ceiling limitations being different from what would have been recorded if the new rules would not have been mandated. See Item 8. "Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures."

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(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31, 2009	December 31, 2008
	(In thousands)	
Natural gas, NGLs and oil revenue sales	$ 29,938	$ 37,982
Joint interest billings	2,328	3,422
Short-term receivable for royalty recoupment	425	481
Total	32,691	41,885

There are no balances in accounts receivable that are considered to be uncollectible and an allowance was unnecessary at December 31, 2009 and 2008.

(4) Property, Plant and Equipment

The Company's total property, plant and equipment consists of the following:

	December 31, 2009	December 31, 2008
	(In thousands)	
Proved properties	$ 1,949,515	$ 1,813,527
Unproved/unevaluated properties	42,344	50,252
Gas gathering system and compressor stations	38,574	36,893
Other	12,417	9,439
Total	2,042,850	1,910,111
Less: Accumulated depreciation, depletion, and amortization	(1,452,248)	(935,851)
	$ 590,602	$ 974,260

Included in the Company's oil and natural gas properties are asset retirement costs of $21.9 million and $23.2 million at December 31, 2009 and 2008, respectively, including additions of $1.9 million and $1.7 million for the year ended December 31, 2009 and 2008, respectively.

As discussed in Note 2, pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and gas assets within each separate cost center. The Company recorded a non-cash, pre-tax write-down of $379.5 million at March 31, 2009. There were no other ceiling test write-downs recorded during the year ended December 31, 2009. However, due to the volatility of commodity prices, should oil and natural gas prices decline in the future, it is possible that an additional write-down could occur.

The Company also recorded a non-cash, pre-tax write-down of $205.7 million at September 30, 2008. Due to continued declines in oil and gas prices and a downward revision of 8 Bcfe due to year-end commodity prices, at December 31, 2008, capitalized costs of our proved oil and gas properties exceeded our ceiling, resulting in an additional non-cash, pre-tax write-down of $238.7 million.

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Capitalized costs excluded from DD&A as of December 31, 2009 and 2008, are as follows by the year in which such costs were incurred:

	December 31, 2009				
	Total	2009	2008	2007	Prior
			(in thousands)		
Onshore:					
Development cost	$505	$505	$-	$-	$-
Exploration cost	8,732	8,732	-	-	-
Acquisition cost of undeveloped acreage	31,326	14,165	14,734	2,398	29
Capitalized interest	1,781	83	1,347	349	2
	42,344	23,485	16,081	2,747	31
Offshore:					
Development cost	-	-	-	-	-
Exploration cost	-	-	-	-	-
Acquisition cost of undeveloped acreage	-	-	-	-	-
Capitalized interest	-	-	-	-	-
	-	-	-	-	-
Total capitalized costs excluded from DD&A	$42,344	$23,485	$16,081	$2,747	$31

	December 31, 2008				
	Total	2008	2007	2006	Prior
			(in thousands)		
Onshore:					
Development cost	$13,320	$13,320	$-	$-	$-
Exploration cost	3,555	3,555	-	-	-
Acquisition cost of undeveloped acreage	29,926	23,958	4,949	988	31
Capitalized interest	2,552	1,978	433	141	-
	49,353	42,811	5,382	1,129	31
Offshore:					
Development cost	-	-	-	-	-
Exploration cost	-	-	-	-	-
Acquisition cost of undeveloped acreage	786	-	-	786	-
Capitalized interest	113	-	-	113	-
	899	-	-	899	-
Total capitalized costs excluded from DD&A	$50,252	$42,811	$5,382	$2,028	$31

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $33.1 million and development and exploration costs of $9.2 million will be included in oil and gas properties subject to amortization within five years and one year, respectively.

Property Acquisitions. During the first quarter of 2009, the Company acquired the remaining 10% working interest in the 1,280-acre position Pinedale Anticline in the Rockies for $3.8 million and obtained operatorship.

During the fourth quarter of 2008, the Company acquired a 90% working interest in a 1,280-acre position in the Pinedale Anticline in the Rockies for $35.0 million and a 70% working interest in certain properties in the Catarina

Field and a 35% working interest in a significant acreage position in the Eagle Ford shale in South Texas for $20.0 million.

During the second quarter of 2008, the Company acquired a 50% working interest position in approximately 12,000 gross acres in the Rockies for $29.0 million.

During the second quarter of 2007, the Company acquired properties located in the Sacramento Basin at a total purchase price of $38.7 million.

Gas Gathering System and Compressor Stations. In December 2008, we purchased approximately 62 miles of low pressure gathering from Pacific Gas and Electric for $1.3 million. The gathering system is located in the heart of the Rio Vista field and gathers much of our low pressure production within the Rio Vista field. The gas gathering system and compressor stations of $38.6 million and $36.9 million at December 31, 2009 and 2008, respectively, are primarily located in California and the Rockies, and are recorded at cost and depreciated on a straight-line basis over useful lives of 15 years. The accumulated depreciation for the gas gathering system at December 31, 2009 and 2008 was $7.7 million and $5.3 million, respectively. The depreciation expense associated with the gas gathering system and compressor stations for the years ended December 31, 2009, 2008 and 2007 was $2.5 million, $2.2 million, and $1.5 million, respectively.

Other Property and Equipment. Other property and equipment at December 31, 2009 and 2008 of $12.4 million and $9.4 million, respectively, consists primarily of furniture and fixtures. The accumulated depreciation associated with other assets at December 31, 2009 and 2008 was $4.3 million and $2.6 million, respectively. For the years ended December 31, 2009, 2008 and 2007 depreciation expense for other property and equipment was $1.7 million, $1.2 million, and $0.8 million, respectively.

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(5) Deferred Loan Fees

At December 31, 2009 and 2008, deferred loan fees were $4.9 million and $1.2 million, respectively. Total amortization expense for deferred loan fees was $2.1 million, $1.0 million and $1.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(6) Commodity Hedging Contracts and Other Derivatives

The following financial fixed price swap and costless collar transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations at December 31, 2009:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Natural Gas Production Hedged (1)	Fair Market Value Asset/(Liability) (In thousands)
2010	Swap	Cash flow	15,000	5,475,000	$ 7.46	$ -	13 %	$ 8,834
2010	Costless Collar	Cash flow	15,041	5,490,000	5.75	7.40	13 %	548
2011	Swap	Cash flow	5,000	1,825,000	5.72		5 %	(408)
2011	Costless Collar	Cash flow	25,000	9,125,000	5.80	7.58	23 %	(1,552)
				21,915,000				$ 7,422

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(1) Estimated based on anticipated future gas production.

The Company has hedged the interest rates on $100.0 million of its outstanding debt through December 31, 2010. As of December 31, 2009, the Company had the following financial interest rate swap positions outstanding:

Settlement Period	Derivative Instrument	Hedge Strategy	Average Fixed Rate	Fair Market Value Asset/(Liability) (In thousands)
January 1 - December 31, 2010	Swap	Cash Flow	1.24 %	$ (635)

The Company’s current cash flow hedge positions are with counterparties who are also lenders in the Company’s credit facilities. This eliminates the need for independent collateral postings with respect to any margin obligation resulting from a negative change in fair market value of the derivative contracts in connection with the Company’s hedge related credit obligations. As of December 31, 2009, the Company made no deposits for collateral.

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The following table sets forth the results of hedge transaction settlements for the respective period for the Consolidated Statement of Operations:

	For the Year Ended December 31, 2009	For the Year Ended December 31, 2008
Natural Gas		
Quantity settled (MMBtu)	20,856,465	26,684,616
Increase (decrease) in natural gas sales revenue (In thousands)	$ 76,567	$ (18,669)
Interest Rate Swaps		
Increase in interest expense (In thousands)	$ (1,289)	$ (1,158)

As of December 31, 2009, the Company expects to reclassify gains of $8.7 million to earnings from the balance in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet during the next twelve months.

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivative instruments are commodity price risk and interest rate risk. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company's natural gas and oil production. Interest rate swaps are entered into to manage interest rate risk associated with the Company's variable-rate borrowings.

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the statement of financial position. In accordance with this guidance, the Company designates commodity forward contracts as cash flow hedges of forecasted sales of natural gas and oil production and interest rate swaps as cash flow hedges of interest rate payments due under variable-rate borrowings.

Additional Disclosures about Derivative Instruments and Hedging Activities

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of December 31, 2009, the Company had outstanding natural gas commodity forward contracts with a notional volume of 21,915,000 MMBtus that were entered into to hedge forecasted natural gas sales.

As of December 31, 2009, the total notional amount of the Company's receive-variable/pay-fixed interest rate swaps was $100.0 million. The Company includes the realized gain or loss on the hedged items (that is, interest on variable-rate borrowings) in the same line item – Interest expense, net of interest capitalized – as the offsetting gain or loss on the related interest rate swaps.

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Information on the location and amounts of derivative fair values in the statement of financial position and derivative gains and losses in the statement of operations as of December 31, 2009 is as follows:

Fair Values of Derivative Instruments

Derivative Assets (Liabilities)

	December 31, 2009		
	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments			(in thousands)
Interest rate swap	Derivative Instruments - current assets	$	(399)
Interest rate swap	Derivative Instruments - current liabilities		(236)
Interest rate swap	Derivative Instruments - non-current liabilities		-
Interest rate swap	Other assets - non-current assets		-
Commodity contracts	Derivative Instruments - current assets		9,382
Commodity contracts	Derivative Instruments - non-current liabilities		(1,960)
Total derivatives designated as hedging instruments		$	6,787
Total derivatives not designated as hedging instruments		$	-
Total derivatives		$	6,787

Derivatives in Cash Flow Hedging	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Twelve Months	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Twelve Months	Location of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain or (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) (1) Twelve Months

Relationships	Ended December 31, 2009 (in thousands)		Ended December 31, 2009 (in thousands)		Ended December 31, 2009 (in thousands)
Interest rate swap	$ (1,923)	Interest expense, net of interest capitalized	$ (767)	Interest expense, net of interest capitalized	$ (522)
Commodity contracts	45,616	Natural gas sales	76,567	Natural gas sales	-
Total	$ 43,693	Total	$ 75,800	Total	$ (522)

(1) The amount of gain or (loss) recognized in income represents $0.5 million related to the ineffective portion of the hedging relationships. Nothing was excluded from the assessment of hedge effectiveness.

On April 9, 2009, the Company entered into an amended and restated revolving credit agreement replacing the previous revolving credit agreement. At the time of the amended and restated revolving credit agreement, the Company had two outstanding interest rate swaps which established a fixed interest rate for a portion of the previous outstanding revolver that were designated as cash flow hedges and which became ineffective. During the second quarter of 2009, the Company ceased cash flow hedge accounting for these interest rate swaps which resulted in approximately $0.5 million in interest expense. Because these swaps matured during the quarter ended June 30, 2009, the Company did not recognize any unrealized mark to market gains or losses within the Consolidated Statement of Operations related to the swaps during the period. For the twelve months ended December 31, 2009, there were no gains or losses recognized in income representing hedge components excluded from the assessment of effectiveness.

(7) Fair Value Measurements

The Company adopted the authoritative guidance for fair value measurements effective January 1, 2008 for financial assets and liabilities and effective January 1, 2009 for non-financial assets and liabilities. The Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company discloses its recognized non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company's non-financial assets and liabilities are impaired during the period-ended December 31, 2009, and no other fair value measurements are required to be recognized on a non-recurring basis, no additional disclosures are provided at December 31, 2009.

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As defined in the guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ("exit price"). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of the fair value hierarchy are as follows:

– Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
– Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
– Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Level 3 instruments include money market funds, natural gas swaps, natural gas zero cost collars and interest rate swaps. The Company's money market funds represent cash equivalents whose investments are limited to United States Government Securities, securities backed by the United States Government, or securities of United States Government agencies. The fair value represents cash held by the fund manager as of December 31, 2009 and 2008. The Company identified the money market funds as Level 3 instruments due to the fact that quoted prices for the underlying investments cannot be obtained and there is not an active market for the underlying investments. The Company utilizes counterparty and third party broker quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location.

The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008. As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair value as of December 31, 2009 (In thousands)			
	Level 1	Level 2	Level 3	Total
Assets (liabilities):				
Money market funds	$ -	$ -	$ 2,035	$ 2,035
Commodity derivative contracts	-	-	7,422	7,422
Interest rate swap contracts	-	-	(635)	(635)
Total	$ -	$ -	$ 8,822	$ 8,822

	Fair value as of December 31, 2008 (In thousands)			
	Level 1	Level 2	Level 3	Total
Assets (liabilities):				
Money market funds	$ -	$ -	$ 5,025	$ 5,025
Commodity derivative contracts	-	-	39,357	39,357

Interest rate swap contracts	-	-	(985)	(985)
Total	$ -	$ -	$ 43,397	$ 43,397

The determination of the fair values above incorporates various factors. These factors include the credit standing of the counterparties involved, the impact of credit enhancements and the impact of the Company's nonperformance risk on its liabilities. The Company considered credit adjustments for the counterparties using current credit default swap values and default probabilities for each counterparty in determining fair value and recorded a downward adjustment to the fair value of its derivative assets in the amount of $0.01 million at December 31, 2009.

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy during the years ended December 31, 2009 and 2008. Level 3 instruments presented in the table consist of net derivatives that, in management's judgment, reflect the assumptions a marketplace participant would have used at December 31, 2009 and 2008.

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	For the year ended December 31, 2009		
	Derivatives Asset (Liability)	Money Market Funds Asset (Liability) (in thousands)	Total
Balance at January 1, 2009	$38,372	$5,025	$43,397
Total (gains) losses (realized or unrealized)			
included in earnings	-	10	10
included in other comprehensive income	43,693	-	43,693
Purchases, issuances and settlements	(75,278)	(3,000)	(78,278)
Transfers in and out of level 3	-	-	-
Balance at December 31, 2009	$6,787	$2,035	$8,822
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2009	$-	$-	$-

	For the year ended December 31, 2008		
	Derivatives Asset (Liability)	Money Market Funds Asset (Liability) (in thousands)	Total
Balance at January 1, 2008	$(10,792)	$-	$(10,792)
Total (gains) losses (realized or unrealized)			
included in earnings	-	25	25
included in other comprehensive income	29,337	-	29,337
Purchases, issuances and settlements	19,827	5,000	24,827
Transfers in and out of level 3	-	-	-
Balance at December 31, 2008	$38,372	$5,025	$43,397
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2008	$-	$-	$-

(8) Accrued Liabilities

The Company's accrued liabilities consist of the following:

	December 31,	
	2009	2008
	(In thousands)	

Accrued capital costs	$	18,200	$	26,555
Accrued payroll and employee incentive expense		7,137		5,721
Accrued lease operating expense		8,011		12,196
Asset retirement obligation		956		1,359
Other		2,803		2,993
Total	$	37,107	$	48,824

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(9) Asset Retirement Obligation

Activity related to the Company's asset retirement obligation ("ARO") is as follows:

	For the Year Ended December 31, 2009	2008
	(In thousands)	
ARO at the beginning of the period	$ 27,944	$ 22,670
Revision of previous estimate	(1,886)	1,785
Liabilities incurred during period	1,855	1,727
Liabilities settled during period	(1,328)	(363)
Accretion expense	2,335	2,125
ARO at the end of the period	$ 28,920	$ 27,944

Of the total ARO, the current portion is approximately $1.0 million and $1.4 million at December 31, 2009 and 2008, respectively, and is included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO is approximately $27.9 million and $26.5 million at December 31, 2009 and 2008, respectively, and is included in Other long-term liabilities on the Consolidated Balance Sheet.

(10) Long-Term Debt

Long-term debt consists of the following:

	December 31, 2009	2008
	(In thousands)	
Amended and Restated Senior Revolving Credit Agreement	$ 190,000	$ 225,000
Amended and Restated Second Lien Term Loan	100,000	75,000
	290,000	300,000
Less:		
Original issue discount on amended and restated second lien term loan	(1,258)	-
Current portion of long-term debt	-	-
	$ 288,742	$ 300,000

Senior Secured Revolving Line of Credit. On April 9, 2009, the Company entered into the Restated Revolver providing a senior secured revolving line of credit in the amount of up to $600.0 million, replacing the prior revolving credit agreement, and extending its term until July 1, 2012. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company's hedging arrangements. The borrowing base under the Restated Revolver was set at $375.0 million as of September 30, 2009. The semi-annual borrowing base review was completed during October 2009, and the borrowing base under the Restated Revolver was reduced from $375.0 million to $350.0 million. Amounts outstanding under the Restated Revolver bear interest, as amended, at specified margins over LIBOR of 2.25% to 3.00%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of the Company's domestic subsidiaries, and a pledge of 100% of the membership interests of domestic subsidiaries. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly. At December 31, 2009, the Company's current ratio was 4.3 and the leverage ratio was 1.6. In addition, the Company is subject to covenants, including limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2009. On October 22, 2009, the Company entered into the First Amendment to the Restated Revolver that deletes the "Reference Bank Cost of Funds Rate" option in the definition of Alternate Base Rate, allows the Company to make investments in US government securities, which mature in 15 months rather than one year, provides for certain other modifications to permitted investments, and provides for the release of the Lenders' lien on a certain deposit account. The Company paid a facility fee on the total commitment of $4.6 million. As of December 31, 2009, the Company had $190.0 million outstanding with $160.0 million available for borrowing under the revolving line of credit. All amounts drawn under the Restated Revolver are due and payable on July 1, 2012. As of February 26, 2010, the Company had $190.0 million outstanding with $160.0 million available for borrowing under the revolving line of credit.

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Second Lien Term Loan. On April 9, 2009, the Company also entered into the Restated Term Loan and extended its term until October 2, 2012. Borrowings under the Restated Term Loan were initially set at $75.0 million and bear interest at LIBOR plus 8.5% with a LIBOR floor of 3.5%. In accordance with authoritative guidance for derivative instruments and hedging activities, the Company evaluated the LIBOR floor as an embedded derivative and concluded that because the terms are clearly and closely related to the debt instrument, it does not represent an embedded derivative that must be accounted for separately. The Restated Term Loan had an option to increase fixed and floating rate borrowings by up to $25.0 million to $100.0 million prior to May 9, 2009. The Company exercised this option on April 21, 2009, and the increased borrowings consisted of $5.0 million of floating rate borrowings and $20.0 million of fixed rate borrowings at 13.75%. The loan is collateralized by second priority liens on substantially all of the Company's assets. The Company is subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly. At December 31, 2009, the Company's asset coverage ratio was 2.7 and the leverage ratio was 1.6. In addition, the Company is subject to covenants, including limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2009. On October 22, 2009, the Company also entered into the First Amendment to the Restated Term Loan that deletes the "Reference Bank Cost of Funds Rate" option in the definition of Alternate Base Rate, allows the Company to make investments in US government securities, which mature in 15 months rather than one year, provides for certain other modifications to permitted investments, and provides for the release of the Lenders' lien on a certain deposit account. The Company paid an original issue discount of $1.6 million and a facility fee of $0.9 million on the total commitment. As of December 31, 2009, the Company had $80.0 million of variable rate borrowings and $20.0 million of fixed rate borrowings outstanding under the Restated Term Loan. All amounts drawn under the Restated Term Loan are due and payable on October 2, 2012. The Company has the right to prepay the Restated Term Loan at any time on or after the first anniversary of the effective date (April 10, 2010), in whole or in part, from April 10, 2010 to April 10, 2011 with a premium equal to 2% of such amount prepaid or subsequent to April 10, 2011 without premium or penalty provided that each prepayment is in an amount that is an integral multiple of $1.0 million and not less than $1.0 million, or if such amount is less than $1.0 million, the outstanding principal amount. The Company may not prepay the Restated Term Loan prior to April 10, 2010. There were no additional borrowings under the Restated Term Loan subsequent to December 31, 2009 through the date of this Annual Report on Form 10-K.

Aggregate maturities of long-term debt at December 31, 2009 due in the next five years are $290.0 million due in 2012. At December 31, 2009, the Company's weighted average borrowing rate was 6.24%.

(11) Commitments and Contingencies

The Company is party to various oil and natural gas litigation matters arising out of the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Management does not believe any such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

Lease Obligations and Other Commitments

The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $4.3 million, $3.3 million and $2.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2009 are as follows (In thousands):

2010	$3,025
2011	3,103
2012	3,101
2013	3,130
2014	513
Thereafter	-
	$12,872

The Company also has drilling rig commitments of $3.5 million for 2010.

(12) Stock-Based Compensation

Stock-based compensation expense recorded for all share-based payment arrangements for the years ended December 31, 2009, 2008 and 2007 was $7.5 million, $7.2 million and $6.8 million, respectively, with an associated tax benefit of $2.7 million, $2.9 million and $2.5 million, respectively. During 2009, the Company capitalized $0.4 million of stock-based compensation expense. The remaining unrecognized compensation expense associated with total unvested awards as of December 31, 2009 was approximately $7.0 million.

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2005 Long-Term Incentive Plan

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan (the “Plan”) whereby stock is granted to employees, officers and directors of the Company. The Plan allows for the grant of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards. Employees, non-employee directors and other service providers of the Company and its affiliates who, in the opinion of the Compensation Committee or another Committee of the Board of Directors (the “Committee”), are in a position to make a significant contribution to the success of the Company and the Company’s affiliates are eligible to participate in the Plan. The Plan provides for administration by the Committee, which determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the Plan’s terms. The maximum number of shares available for grant under the Plan was increased from 3,000,000 shares to 4,950,000 shares by vote of the shareholders in 2008. The shares available for grant include these 4,950,000 shares plus any shares of common stock that become available under the Plan for any reason other than exercise, such as shares traded for the related tax liabilities of employees. The maximum number of shares of common stock available for grant of awards under the Plan to any one participant is (i) 300,000 shares during any fiscal year in which the participant begins work for Rosetta and (ii) 200,000 shares during each fiscal year thereafter.

Stock Options

The Company has granted stock options under its 2005 Long-Term Incentive Plan (the “Plan”). Options generally expire ten years from the date of grant. The exercise price of the options cannot be less than the fair market value per share of the Company’s common stock on the grant date. The majority of options generally vest over a three year period.

The weighted average fair value at date of grant for options granted during the years ended December 31, 2009, 2008 and 2007 was $3.42 per share, $9.19 per share, and $9.51 per share, respectively. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	Year Ended December 31,		
	2009	2008	2007
Expected option term (years)	6.5	6.5	6.5
Expected volatility	42.45% - 56.95 %	42.45 %	42.45 %
Expected dividend rate	0.00 %	0.00 %	0.00 %
Risk free interest rate	2.42% - 3.19 %	3.48% - 3.84 %	4.36% - 5.00 %

The Company has assumed an annual forfeiture rate of 13% for the options granted in 2009 based on the Company’s history for this type of award to various employee groups, compared to an annual forfeiture rate of 11% for options granted in 2008. Compensation expense is recognized ratably over the requisite service period.

The following table summarizes information related to outstanding and exercisable options held by the Company’s employees and directors at December 31, 2009:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)

Outstanding at December 31, 2007	972,600	$	17.45				
Granted	209,375		19.13				
Exercised	(214,119)		16.89				
Forfeited	(26,100)		17.57				
Outstanding at December 31, 2008	941,756	$	17.94				
Granted	384,514		7.56				
Exercised	(14,125)		16.16				
Forfeited	(64,176)		17.16				
Outstanding at December 31, 2009	1,247,969	$	14.80				
Options vested and exercisable at December 31, 2009	718,548	$	17.94	5.25		$	1,797

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2009, 2008 and 2007 was $1.1 million, $1.7 million and $3.9 million, respectively. Unrecognized expense as of December 31, 2009 for all outstanding stock options is $1.0 million and will be recognized over a weighted average period of 1.64 years.

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 is $0.1 million, $1.4 million and $0.2 million, respectively.

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Restricted Stock

The Company has granted restricted stock under its 2005 Long-Term Incentive Plan. The majority of restricted stock vests over a three-year period. The fair value of restricted stock grants is based on the value of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company also assumes an annual forfeiture rate of 13% for these awards based on the Company's history for this type of award to various employee groups.

The following table summarizes information related to restricted stock held by the Company's employees and directors at December 31, 2009:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2007	455,425	$ 18.50
Granted	607,079	20.06
Vested	(274,714)	18.31
Forfeited	(70,351)	19.54
Non-vested shares outstanding at December 31, 2008	717,439	$ 19.78
Granted	670,673	7.25
Vested	(209,103)	19.34
Forfeited	(54,351)	16.48
Non-vested shares outstanding at December 31, 2009	1,124,658	$ 12.55

The non-vested restricted stock outstanding at December 31, 2009 generally vests at a rate of 25% on the first anniversary of the date of grant, 25% on the second anniversary and 50% on the third anniversary. The fair value of awards vested for the year ended December 31, 2009 was $1.8 million.

Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2009, 2008 and 2007 was $5.1 million, $5.5 million and $2.9 million, respectively. Unrecognized expense as of December 31, 2009 for all outstanding restricted stock awards is $6.0 million and will be recognized over a weighted average period of 1.70 years.

Performance Share Units

Pursuant to the approved Amended and Restated 2005 Long-Term Incentive Plan, the Company's Compensation Committee agreed to allocate a portion of the 2009 long-term incentive grants to executives as PSUs. The PSUs are payable, at the Company's option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock at settlement based on the achievement of certain performance metrics or market conditions at the end of a three-year performance period. The Company's current intent is to settle these awards in cash. Consequently, the PSUs are accounted for as liability-classified awards and are included as a component of other long-term liabilities. At the end of the three-year performance period, the number of shares vested can range from 0% to 200% of the targeted amount as determined by the Compensation Committee of the Board of Directors. The PSUs have no voting rights. PSUs may be vested solely at the discretion of the Board in the event of a participant's involuntary termination of employment for reasons other than cause or termination for good reason but will be forfeited in the event of the participant's voluntary termination or involuntary termination for cause. Any PSUs not vested by the Board at the end of a performance period will expire.

As discussed in Note 2, compensation expense associated with PSUs is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions or a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and historical forfeitures, and the Board's anticipated vesting percentage. Compensation expense for awards with market conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model.

At December 31, 2009, one-third of the PSUs granted to executive employees include various market-based components requiring complex modeling to value the grant and these grants vest at the end of a three-year performance period based on the comparative performance of the Company's change in cash flow multiple (share price divided by trailing twelve months cash flow per share) against the change in cash flow multiple of the Index. The Company uses a Monte Carlo model which incorporates a risk-neutral valuation approach to value these awards. This model samples paths of the Company's and the Index's stock price and calculates the resulting change in cash flow multiple at the end of the forecasted performance period. This model iterates these randomly forecasted results until the distribution of results converge on a mean or estimated fair value. The five primary inputs for the Monte Carlo model are the risk-free rate, independent analyst cash flow per share estimates for the Company and the Index, volatility of the equities of the Company and the Index, expected dividends, where applicable, and various historical market data. The risk-free rate was generated from Bloomberg for United States Treasuries with a two-year tenor. Volatility was set equal to the annualized daily volatility measured over a historic 400-day period ending on the reporting date for the Company and the Index. No forfeiture rate is assumed for this type of award. Expense related to these awards can be volatile based on the Company's comparative performance at the end of each quarter.

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The following assumptions were used as of December 31, 2009 for the Monte Carlo model to value the expense and liability components of the awards that contain market conditions:

	December 31, 2009
Expected term of award (years)	3
Risk-free interest rate	1.28 %
Rosetta volatility	79.43 %
Index volatility	79.40 %
Rosetta/Index correlation	82 %

The following table summarizes information related to PSUs held by the Company's officers at December 31, 2009:

	Units
Unvested PSUs at December 31, 2008	-
Granted	355,848
Vested	-
Forfeited	(10,318)
Unvested PSUs at December 31, 2009	345,530

The fair value per unit at December 31, 2009 was $19.92 for awards with performance conditions and $19.70 for awards with market conditions. As of December 31, 2009, the Company recognized $1.3 million of compensation expense and long-term liability associated with the PSUs. At the current fair value and assuming that the Board elects 100% pay-out for the PSUs for all metrics, total compensation expense related to the PSUs to be recognized ratably over the 3-year service period would be $6.9 million at December 31, 2009. The total compensation expense will be measured and adjusted quarterly until settlement based on the quarter-end closing common stock prices and the Monte Carlo model valuations.

(13) Income Taxes

The Company's income tax expense (benefit) consists of the following:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Current:			
Federal	$ (1,611)	$ 2,304	$ -
State	416	1,388	115
	(1,195)	3,692	115
Deferred:			
Federal	(119,111)	(107,568)	31,979
State	(5,521)	(8,951)	1,938
	(124,632)	(116,519)	33,917
Total income tax expense (benefit) (1)	$ (125,827)	$ (112,827)	$ 34,032

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(1) Interest and penalties are classified as a component of tax expense in the Consolidated Statement of Operations.

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The differences between income taxes computed using the statutory federal income tax rate and that shown in the statement of operations are summarized as follows:

	Year Ended December 31,					
	2009		2008		2007	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US Statutory Rate	$ (120,751)	35.0 %	$ (105,327)	35.0 %	$ 31,933	35.0 %
Income/franchise tax, net of federal benefit	(5,545)	1.6 %	(7,562)	2.5 %	2,053	2.3 %
Permanent differences and other	469	(0.1)%	62	0.0 %	46	0.0 %
Total tax expense (benefit)	$ (125,827)	36.5 %	$ (112,827)	37.5 %	$ 34,032	37.3 %

The effective tax rate in all periods is the result of the earnings in various domestic tax jurisdictions that apply a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate due primarily to state taxes. Future effective tax rates could be adversely affected if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities.

The components of deferred taxes are as follows:

	December 31,	
	2009	2008
	(In thousands)	
Deferred tax assets		
Oil and gas properties basis differences	$ 130,562	$ 39,089
Alternative Minimum Tax credit	693	2,443
Accrued liabilities not currently deductible	6,501	2,603
Hedge activity	730	-
Net operating loss carryforward	31,429	621
Other	(183)	1,158
Total deferred tax assets	169,732	45,914
Hedge activity	(3,258)	(14,294)
Other	-	(1,543)
Total gross deferred tax liabilities	(3,258)	(15,837)
Net deferred tax assets	$ 166,474	$ 30,077

The Company had a deferred tax asset related to federal and state net operating loss carryforwards of approximately $31.4 million and $9.7 million at December 31, 2009 and 2008, respectively. The federal net operating loss carryforward will begin to expire in 2025. Additionally, the Company had a deferred tax asset related to oil and gas properties basis of $130.8 million and $39.1 million at December 31, 2009 and 2008, respectively. Realization of the deferred tax assets is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced. There is no valuation allowance recorded on deferred tax assets as the Company believes it is more likely than not that the asset will be utilized.

As of December 31, 2009, the Company is not aware of any uncertain tax positions requiring adjustments to its tax liability. If applicable, the Company will record to the income tax provision any interest and penalties related to unrecognized tax positions.

The Company files income tax returns in the U.S. and in various state jurisdictions. With few exceptions, the Company is subject to US federal, state and local income tax examinations by tax authorities for tax periods 2005 and forward.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the consolidated statement of operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

(14) Earnings Per Share

Basic earnings per share ("EPS") is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if contracts to issue common stock and stock options were exercised at the end of the period.

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The following is a calculation of basic and diluted weighted average shares outstanding:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Basic weighted average number of shares outstanding	50,979	50,693	50,379
Dilution effect of stock option and awards at the end of the period (1)	-	-	210
Diluted weighted average number of shares outstanding	50,979	50,693	50,589
Anti-dilutive stock options and awards	1,364	592	385

(1) Because the Company recognized a net loss for the years ended December 31, 2009 and 2008, no unvested stock awards and options were included in computing earnings per share because the effect was anti-dilutive. In computing earnings per share, no adjustments were made to reported net income (loss).

(15) Operating Segments

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. Also, as all of the Company's operations are located in the U.S., all of the Company's costs are included in one cost pool. See below for information by geographic location.

Geographic Area Information

The Company owns oil and natural gas interests in six main geographic areas, all within the United States or its territorial waters. Geographic revenue and property, plant and equipment information below are based on physical location of the assets at the end of each period:

	Year Ended December 31,		
	2009 (1)	2008 (1)	2007 (1)
Natural gas, oil and NGL Revenue		(In thousands)	
California	$ 65,295	$ 141,569	$ 110,607
Rockies	21,999	29,491	10,676
South Texas	90,043	204,791	143,886
Texas State Waters	10,465	49,745	8,789
Other Onshore	17,742	44,809	25,905
Gulf of Mexico	11,840	47,611	40,700
	$ 217,384	$ 518,016	$ 340,563

	December 31,	
	2009	2008
Oil and Natural Gas Properties and Other Fixed Assets	(In thousands)	
California	$ 624,765	$ 619,593
Rockies	202,502	175,294

South Texas	791,934	712,464
Texas State Waters	70,667	65,085
Other Onshore	186,912	171,855
Gulf of Mexico	153,653	156,381
Other	12,417	9,439
	$ 2,042,850	$ 1,910,111

(1) Excludes the effects of hedging gains of $76.6 million for the year ended December 31, 2009, hedging losses of $18.7 million for the year ended December 31, 2008 and hedging gains of $22.9 million for the year ended December 31, 2007.

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Major Customers

For the year ended December 31, 2009, the Company had one major customer, CES, which accounted for approximately 57% of the Company's consolidated annual revenue. The Company's annual consolidated revenue from CES accounted for approximately 61% and 55% for the years ended December 31, 2008 and 2007, respectively, and is reflected in oil and natural gas sales. For the years ended December 31, 2009, 2008 and 2007, revenues from sales to CES were $117.8 million, $305.9 million, and $201.4 million, respectively. There was no receivable from CES at December 31, 2009 or 2008. Under the gas purchase and sale contract, CES is required to collateralize payments under the contract by daily margin payments into the Company's collateral account, which are then settled at the end of the month. At December 31, 2009 and 2008, the Company had $7.5 million and $19.4 million in the margin account for December sales to CES which is included in Prepayment on gas sales on the Consolidated Balance Sheet.

(16) Subsequent Events

On January 26, 2010, the Company entered into a purchase and sale agreement with St. Mary Land & Exploration Company to purchase the remaining 30% working interest and obtain operatorship in the Catarina Field for approximately $5.9 million, subject to any applicable purchase price adjustments. The purchase is effective as of January 1, 2010 and closing shall occur on or before March 4, 2010, but no later than May 1, 2010.

In January 2010, the Company entered into additional costless collar transactions to hedge 10,000 MMBtu/d of its expected production for July 2010 through December 2012. The costless collars have a floor price of $5.75 per MMBtu and a ceiling price of $6.50 per MMBtu through 2011 and $7.15 per MMBtu in 2012. In February 2010, the Company entered into natural gas fixed-price swaps to hedge 10,000 MMBtu/d of its expected production for July 2010 through December 2011 at an average price of $5.91 per MMBtu.

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Supplemental Oil and Gas Disclosures

(Unaudited)

The following disclosures for the Company are made in accordance with authoritative guidance regarding disclosures about oil and natural gas producing activities. Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Additionally, in December 2008, the SEC issued new disclosure requirements that require reporting of oil and gas reserves using an average first day of the month historical price based upon the prior twelve-month period rather than year-end prices and the use of reliable technologies to determine proved reserves if those technologies have been demonstrated to result in reasonable certainty of economic producibility of reserves volumes. Under this guidance, companies are required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. These new disclosure requirements became effective beginning with the annual report on Form 10-K for the year ending December 31, 2009. In October 2009, the SEC issued Staff Accounting Bulletin (“SAB”) No. 113 to bring existing SEC guidance into conformity with the Release. The principle revisions of the guidance include changing the price used in determining quantities of oil and gas reserves, as noted above; eliminating the option to use post-quarter-end prices to evaluate write-offs of excess capitalized costs under the full cost method of accounting; removing the exclusion of unconventional methods used in extracting oil and gas from oil sands or shale as an oil and gas producing activity; and removing certain questions and interpretative guidance which are no longer necessary. In January 2010, the FASB issued its guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC’s final rule.

Proved reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

Proved developed reserves are proved reserves that can be expected to be recovered (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Estimates of proved developed and proved undeveloped reserves as of December 31, 2009 are based on estimates made by the Company's engineers and audited by NSAI, independent engineers. The Company's primary reserves estimator is the Company's Chief Engineer and Operations General Manager who has twenty-two years of experience in the petroleum industry with 18 years of experience in the evaluation of reserves and income attributable to oil and gas properties. She holds a Bachelor of Science in Petroleum Engineering, a Bachelor of Science in Geosciences and a Master of Business Administration from the University of Tulsa. She also holds a Master of Science in Petroleum Engineering from the University of Houston. She obtained a Doctor of Jurisprudence from South Texas College of Law and is a member of Phi Delta Phi honorary law society and the Society of Petroleum Engineers. Estimates of proved developed and proved undeveloped reserves as of December 31, 2008 and 2007 were based on estimates made by NSAI who were engaged by and provided their reports to our senior management team. We make representations to the independent engineers that we have provided all relevant operating data and documents, and in turn, we review these reserve reports provided by the independent engineers to ensure completeness and accuracy. NSAI performs petroleum engineering consulting services under the Texas Board of Professional Engineers. NSAI's President and Chief Operating Officer is a licensed professional engineer with more than 30 years of experience and the geoscientist charged with the audit is a licensed professional with 25 years of experience.

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The preparation of our reserve estimates are completed in accordance with the Company's prescribed internal control procedures, which include verification of input data into a reserve forecasting and economic evaluation software, as well as management review. The technical persons responsible for preparing the reserve estimates meet the required standards regarding qualifications and objectivity. Additionally, the Company engages qualified, independent reservoir engineers to audit the internally generated reserve report in accordance with all SEC reserve estimation guidelines.

A twelve-month first day of the month historical average price as of December 31, 2009 was used for future sales of natural gas, crude oil and NGLs. As of December 31, 2008 and 2007, market prices as of each year-end were used for future sales of natural gas, crude oil and NGLs. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company's natural gas and crude oil producing activities at December 31, 2009, 2008 and 2007:

	2009	2008	2007
		(In thousands)	
Proved properties	$ 1,949,515	$ 1,813,527	$ 1,499,046
Unproved properties	42,344	50,252	40,903
Total	1,991,859	1,863,779	1,539,949
Less: Accumulated depreciation, depletion, and amortization	(1,440,204)	(927,961)	(291,321)
Net capitalized costs	$ 551,655	$ 935,818	$ 1,248,628

Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include asset retirement costs of $21.9 million, $23.2 million and $20.1 million as of December 31, 2009, 2008 and 2007, respectively.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's oil and natural gas activities for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Acquisition costs of properties			
Proved	$ 11,490	$ 103,177	$ 40,760
Unproved	28,246	32,276	23,824

Subtotal	39,736	135,453	64,584
Exploration costs	24,550	35,735	90,117
Development costs	65,183	152,260	178,894
Total	$ 129,469	$ 323,448	$ 333,595

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Results of operations for oil and natural gas producing activities

	Year Ended December 31, 2009 (1)	2008 (1)	2007 (1)
		(In thousands)	
Natural gas, oil, and NGL producing revenues	$ 217,384	$ 518,016	$ 340,563
Production costs	73,172	78,609	60,140
Depreciation, depletion, and amortization	121,042	198,862	152,882
Impairment of oil and gas properties	379,462	444,369	-
Income (loss) before income taxes	(356,292)	(203,824)	127,541
Income tax provision (benefit)	(130,047)	(76,434)	47,573
Results of operations	$ (226,245)	$ (127,390)	$ 79,968

(1) Excludes the effects of hedging gains of $76.6 million for the year ended December 31, 2009, hedging losses of $18.7 million for the year ended December 31, 2008 and hedging gains of $22.9 million for the year ended December 31, 2007.

The results of operations for oil and natural gas producing activities exclude interest charges and general and administrative expenses. Sales are based on market prices.

Net Proved and Proved Developed Reserve Summary

The following table sets forth the Company's net proved and proved developed reserves (all within the United States) at December 31, 2009, 2008, and 2007, as estimated by the Company's reservoir engineers and audited by independent petroleum consultants in 2009 and as estimated by independent petroleum consultants for 2008 and 2007 and the changes in the net proved reserves for each of the three years then ended. There was no restatement of 2008 and 2007 reserves as a result of the new reserve reporting guidance.

	Natural gas (Bcf)(1):	Natural gas liquids and crude oil (MBbl)(2)(3):	Bcfe (1) equivalents (4):
Net proved reserves at December 31, 2006 (5)	390	2,930	408
Revisions of previous estimates	(30)	-	(30)
Purchases in place	10	-	10
Extensions, discoveries and other additions	72	652	76
Sales in place	-	-	-
Production	(42)	(561)	(46)
Net proved reserves at December 31, 2007 (5)	400	3,021	418
Revisions of previous estimates (6)	(77)	779	(72)
Purchases in place	63	293	65
Extensions, discoveries and other additions	38	418	40
Sales in place	-	-	-
Production	(48)	(908)	(53)
Net proved reserves at December 31, 2008	376	3,603	398
Revisions of previous estimates (7)	(67)	3,146	(48)
Purchases in place	3	25	3

Extensions, discoveries and other additions	32	3,603	54
Sales in place	(3)	(317)	(6)
Production	(44)	(1,014)	(50)
Net proved reserves at December 31, 2009	297	9,046	351

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Net proved developed reserves

	Proved Developed Reserves		
	Natural gas (Bcf) (1)	Natural gas liquids and crude oil (MBbl) (2) (3)	Equivalents Bcfe (4)
December 31, 2007 (5) (8)	286	2,658	302
December 31, 2008 (8)	308	3,253	327
December 31, 2009	237	4,669	265

(1) Billion cubic feet or billion cubic feet equivalent, as applicable
(2) Thousand barrels
(3) Includes crude oil, condensate and natural gas liquids
(4) Natural gas liquids and crude oil volumes have been converted to equivalent natural gas volumes using a conversion factor of six cubic feet of natural gas to one barrel of natural gas liquids and crude oil.
(5) Excludes estimated reserves pertaining to interests in certain leases and wells associated with the Non-Consent Properties.
(6) Downward revision of 64 Bcfe of proved reserves and 8 Bcfe due to year-end commodity prices. The Company's downward revision of 64 Bcfe of proved reserves consisted of performance revisions of 35 Bcfe in California and 25 Bcfe in the South Texas Lobo trend with the remainder spread across a variety of asset areas. In both cases, the performance revisions were driven by new data and not by a change in reserve evaluation methodology.
(7) Downward revision of 48 Bcfe of proved reserves primarily due to the use of the twelve-month first day of the month historical average oil and gas price used to calculate the December 31, 2009 reserves instead of the use of year-end commodity prices as previously required.
(8) There was no restatement of 2008 and 2007 proved developed reserves as a result of the new reserve reporting guidance.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by authoritative guidance and based on natural gas and crude oil reserve and production volumes estimated by internal reserves engineers and audited by independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. In accordance with SEC requirements, the estimated discounted future net revenues from proved reserves are generally based on average first day of the month oil and gas prices in effect for the prior twelve months in 2009 and costs as of the date of the estimate and, in 2008 and 2007, prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs are as of the date of the estimate. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and natural gas assets. Changes in reserve reporting requirements negatively impacted the Company's Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves as the twelve-month first day of the month historical average price was significantly lower than the year-end price at December 31, 2009.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and natural gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

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The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's natural gas and crude oil reserves for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31, 2009		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$1,153	$ 407	$1,560
Future production costs	(503)	(90)	(593)
Future development costs	(58)	(142)	(200)
Future income taxes (1)	-	-	-
Future net cash flows	592	175	767
Discount to present value at 10% annual rate	(209)	(93)	(302)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$383	$ 82	$465

	Year Ended December 31, 2008		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$1,983	$ 454	$2,437
Future production costs	(686)	(90)	(776)
Future development costs	(95)	(174)	(269)
Future income taxes	(143)	(23)	(166)
Future net cash flows	1,059	167	1,226
Discount to present value at 10% annual rate	(402)	(83)	(485)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$657	$ 84	$741

	Year Ended December 31, 2007		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$2,183	$ 843	$3,026
Future production costs	(640)	(179)	(819)
Future development costs	(88)	(214)	(302)
Future income taxes	(247)	(76)	(323)
Future net cash flows	1,208	374	1,582
Discount to present value at 10% annual rate	(458)	(170)	(628)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$750	$ 204	$954

(1) For the year ended December 31, 2009, the future revenues and expenses associated with oil and gas properties did not exceed the Company's current tax basis of oil and gas properties, thus resulting in no future income tax expense. This is calculated using the twelve-month first day of the month historical average pricing.

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Changes in Standardized Measure of Discounted Future Net cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2009, 2008 and 2007:

	(In millions)
Balance December 31, 2006 (1)	$ 722
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(303)
Net changes in prices and production costs	253
Extensions, discoveries, additions and improved recovery, net of related costs	283
Development costs incurred	92
Revisions of previous quantity estimates and development costs	(76)
Accretion of discount	79
Net change in income taxes	(113)
Purchases of reserve in place	38
Sales of reserves in place	-
Changes in timing and other	(21)
Balance December 31, 2007 (1)	954
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(439)
Net changes in prices and production costs	(73)
Extensions, discoveries, additions and improved recovery, net of related costs	123
Development costs incurred	98
Revisions of previous quantity estimates and development costs	(191)
Accretion of discount	114
Net change in income taxes	95
Purchases of reserve in place	119
Sales of reserves in place	-
Changes in timing and other	(59)
Balance December 31, 2008	741
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(221)
Net changes in prices and production costs	(348)
Extensions, discoveries, additions and improved recovery, net of related costs	69
Development costs incurred	114
Revisions of previous quantity estimates and development costs	(71)
Accretion of discount	84
Net change in income taxes	100
Purchases of reserve in place	5
Sales of reserves in place	(9)
Changes in timing and other	1
Balance December 31, 2009	$ 465

(1) Excludes non-consent properties related to the Calpine litigation.

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Rosetta Resources Inc.
Selected Data
Quarterly Information
(Unaudited)

Summaries of the Company's results of operations by quarter for the years ended 2009 and 2008 are as follows:

	2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 79,441	$ 73,550	$ 64,484	$ 76,476
Impairment of oil and gas properties	(379,462)	-	-	-
Operating income (loss)	(375,177)	12,820	14,788	20,851
Net income (loss)	(238,133)	4,035	5,731	9,191
Basic earnings (loss) per share	(4.68)	0.08	0.11	0.19
Diluted earnings (loss) per share	(4.68)	0.08	0.11	0.19

	2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 128,333	$ 154,467	$ 130,036	$ 86,512
Impairment of oil and gas properties	-	-	(205,659)	(238,710)
Operating income (loss)	45,908	66,730	(155,806)	(232,170)
Net income (loss)	27,489	39,315	(99,375)	(155,539)
Basic earnings (loss) per share	0.54	0.78	(1.96)	(3.06)
Diluted earnings (loss) per share	0.54	0.77	(1.96)	(3.06)

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended ("Exchange Act"), as of December 31, 2009. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2009, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a – 15(f). Management conducted an assessment as of December 31, 2009 of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2009, based on criteria in Internal Control – Integrated Framework issued by the COSO.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2010 annual meeting under the headings "Security Ownership of Directors and Executive Officers," "Company Nominees for Director," "Section 16(a) Beneficial Ownership Reporting Compliance," and "Corporate Governance and Committees of the Board."

Item 11. Executive Compensation

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2010 annual meeting under the headings "Executive Compensation," "Information Concerning the Board of Directors," and "Compensation Committee Report."

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

This information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2010 annual meeting under the headings "Security Ownership of Certain Beneficial Owners and Management" and "Securities Authorized for Issuance Under Equity Compensation Plans."

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2010 annual meeting under the heading "Certain Transactions" and "Corporate Governance and Committees of the Board."

Item 14. Principal Accountant Fees and Services

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2010 annual meeting under the heading "Audit and Non-Audit Fees Summary."

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Part IV

Item 15. Exhibits and Financial Statement Schedules

a. The following documents are filed as a part of this report or incorporated herein by reference:

(1) Our Consolidated Financial Statements are listed on page 44 of this report.

(2) Financial Statement Schedules:

None

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 10, 2008 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.1	Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.2	Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.3	Settlement Agreement and Amendment with Calpine Corporation (incorporated herein by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.4	Amended and Restated Base Contract for Sale and Purchase of Natural Gas with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.5	Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.9 †	

	Amended and Restated 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.10 †	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11 †	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12 †	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.18	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).

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10.19	Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company's Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.21	Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.25	First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.31 †	Amended and Restated Employment Agreement with Randy L. Limbacher (incorporated herein by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.32 †	Amended and Restated Employment Agreement with Michael J. Rosinski (incorporated herein by reference to Exhibit 10.32 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.33 †	Amended Employment Agreement with Charles S. Chambers (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on November 9, 2007).
10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q filed on November 9, 2007).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to Form 10-Q filed on November 9, 2007).
10.36 †	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.37 †	Amended and Restated Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).

10.38 †	Amended and Restated Employment Agreement with Edward E. Seeman (incorporated herein by reference to Exhibit 10.38 to Form 10-K filed February 29, 2008).
10.39 †	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.40 †	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.41 †	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.42 †*	Executive Employee Change of Control Plan
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company's Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.45	First Amendment dated October 22, 2009 to Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.45 to the Company's Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).

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21.1*	Subsidiaries of the registrant
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Netherland, Sewell & Associates, Inc.

* Filed herewith

† Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 26, 2010.

ROSETTA RESOURCES INC.	
By:	/s/ Randy L. Limbacher Randy L. Limbacher, Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ Randy L. Limbacher Randy L. Limbacher	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2010
/s/ Michael J. Rosinski Michael J. Rosinski	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2010
/s/ W. Rufus Estis W. Rufus Estis	Vice President, Controller (Principal Accounting Officer)	February 26, 2010
/s/ D. Henry Houston D. Henry Houston	Lead Director	February 26, 2010
/s/ Richard W. Beckler Richard W. Beckler	Director	February 26, 2010
/s/ Matt Fitzgerald Matt Fitzgerald	Director	February 26, 2010
/s/ Philip L. Frederickson Philip L. Frederickson	Director	February 26, 2010
/s/ Josiah O. Low, III Josiah O. Low, III	Director	February 26, 2010
/s/ Donald D. Patteson, Jr.	Director	

	February 26, 2010
Donald D. Patteson, Jr.	

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Glossary of Oil and Natural Gas Terms

We are in the business of exploring for and producing oil and natural gas. Oil and natural gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and natural gas industry. The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

3-D Seismic. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional seismic data.

Amplitude. The difference between the maximum displacement of a seismic wave and the point of no displacement, or the null point.

(Amplitude plays) anomalies. An abrupt increase in seismic amplitude that can in some instances indicate the presence of hydrocarbons.

Analogous reservoir. Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest; (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

Anticline. An arch-shaped fold in rock in which layers are upwardly convex, often forming a hydrocarbon trap. Anticlines may form hydrocarbon traps, particularly in folds with reservoir-quality rocks in their core and impermeable seals in the outer layers of the fold.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Behind Pipe Pays. Reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams, issued by a state bordering on the Gulf of Mexico.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Coalbed methane. Coal is a carbon-rich sedimentary rock that forms from the remains of plants deposited as peat in swampy environments. Natural gas associated with coal, called coal gas or coalbed methane, can be produced economically from coal beds in some areas.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Economically producible. The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

Estimated ultimate recovery. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. Optimizing oil and gas production from producing properties or establishing additional reserves in producing areas through additional drilling or the application of new technology.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Fault. A break or planar surface in brittle rock across which there is observable displacement.

Faulted downthrown rollover anticline. An arch-shaped fold in rock in which the convex geological structure is tipped as opposed to perpendicular to the ground and in which a visible break or displacement has occurred in brittle rock, often forming a hydrocarbon trap.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development costs. Capital costs incurred in the acquisition, exploration, development and revisions of proved oil and natural gas reserves divided by proved reserve additions.

Fracing or fracture stimulation technology. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

Gas. Natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well that has the ability to produce higher volumes than a vertical well drilled in the same formation.

Hydrocarbon indicator. A type of seismic amplitude anomaly, seismic event, or characteristic of seismic data that can occur in a hydrocarbon-bearing reservoir.

Infill well. A well drilled between known producing wells to better exploit the reservoir.

Injection well or injection. A well which is used to place liquids or natural gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Lease operating expenses. The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

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MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMcfe/d. MMcfe per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Nonoperated working interests. The working interest or fraction thereof in a lease or unit, the owner of which is without operating rights by reason of an operating agreement.

NYMEX. New York Mercantile Exchange.

Operated working interests. Where the working interests for a property are co-owned, and where more than one party elects to participate in the development of a lease or unit, there is an operator designated “for full control of all operations within the limits of the operating agreement” for the development and production of the wells on the co-owned interests. The working interests of the operating party become the “operated working interests.”

Pay. A reservoir or portion of a reservoir that contains economically producible hydrocarbons. The overall interval in which pay sections occur is the gross pay; the smaller portions of the gross pay that meet local criteria for pay (such as a minimum porosity, permeability and hydrocarbon saturation) are net pay.

Payout. Generally refers to the recovery by the incurring party of its costs of drilling, completing, equipping and operating a well before another party’s participation in the benefits of the well commences or is increased to a new level.

Permeability. The ability, or measurement of a rock’s ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily are described as permeable and tend to have many large, well-connected pores.

Porosity. The percentage of pore volume or void space, or that volume within rock that can contain fluids.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil and natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission’s practice, to determine their “present value.” The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved oil and gas reserves or Proved reserves. Proved oil and gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

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The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the twelve-month first day of the month historical average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project.

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life index. This index is calculated by dividing year-end reserves by the average production during the past year to estimate the number of years of remaining production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

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Secondary recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Natural gas injection and waterflooding are examples of this technique.

Shelf. Areas in the Gulf of Mexico with depths less than 1,300 feet. Our shelf area and operations also includes a small amount of properties and operations in the onshore and bay areas of the Gulf Coast.

Stratigraphy. The study of the history, composition, relative ages and distribution of layers of the earth's crust.

Stratigraphic trap. A sealed geologic container capable of retaining hydrocarbons that was formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

Tcf. Trillion cubic feet of natural gas.

Tcfe. Trillion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Trap. A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not escape.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether or not such acreage contains proved reserves.

Undeveloped oil and gas reserves or Undeveloped reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Waterflooding. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Workover. The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

Workover rig. A portable rig used to repair or adjust downhole equipment on an existing well.

/d. "Per day" when used with volumetric units or dollars.

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Index to Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 10, 2008 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.1	Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.2	Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.3	Settlement Agreement and Amendment with Calpine Corporation (incorporated herein by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.4	Amended and Restated Base Contract for Sale and Purchase of Natural Gas with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.5	Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.9 †	Amended and Restated 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.10 †	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11 †	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12 †	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No.

	333-128888)).
10.18	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.19	Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company's Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.21	Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.25	First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).

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10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.31 †	Amended and Restated Employment Agreement with Randy L. Limbacher (incorporated herein by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.32 †	Amended and Restated Employment Agreement with Michael J. Rosinski (incorporated herein by reference to Exhibit 10.32 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.33 †	Amended Employment Agreement with Charles S. Chambers (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on November 9, 2007).
10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q filed on November 9, 2007).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to Form 10-Q filed on November 9, 2007).
10.36 †	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.37 †	Amended and Restated Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.38 †	Amended and Restated Employment Agreement with Edward E. Seeman (incorporated herein by reference to Exhibit 10.38 to Form 10-K filed February 29, 2008).
10.39 †	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.40 †	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.41 †	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.42 †*	Executive Employee Change of Control Plan
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company's Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.45	

	First Amendment dated October 22, 2009 to Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.45 to the Company's Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
21.1*	Subsidiaries of the registrant
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.

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99.1*	Report of Netherland, Sewell & Associates, Inc.

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* Filed herewith

† Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.