Rosetta Resources Inc.
Form 10-K
February 25, 2011

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, 2010

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 x No o

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

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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 x	Accelerated filer o
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, 2010 was approximately $1.0 billion based on the closing price of $19.81 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 18, 2011 was 52,879,723.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2011 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 80.

Part I

Items 1 and 2. Business and Properties

General

We are an independent exploration and production company engaged in the exploration, development, production and acquisition of onshore oil and gas resources in the United States of America. Our operations are concentrated in South Texas, including our largest producing area in the Eagle Ford shale, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in Montana. Our headquarters are located at 717 Texas, Suite 2800, Houston, Texas 77002. We also have field offices in Laredo and Catarina, Texas, Rio Vista, California and Wray, Colorado.

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

We sell most of our California 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 approach is consistent with our strategy to become a successful unconventional resource player with sufficient project inventory to drive significant growth. We recognize that there may be market cycles that could impact our ability to fully execute our strategy on a short-term basis. However, we believe our plan is fundamentally sound and emphasizes (i) developing our high return inventory in the Eagle Ford shale in South Texas, (ii) establishing and testing positions in emerging resource plays, (iii) divesting lower return assets to fund and accelerate our unconventional resource initiatives, (iv) applying technological expertise, (v) focusing on cost control and (vi) maintaining financial flexibility. We seek to implement our strategy while increasing stockholder value through sound stewardship, wise capital resource management, taking advantage of business cycles and emerging trends and minimizing liabilities through governmental compliance and protecting the environment. Below is a discussion of the key elements of our strategy.

Develop Our High Return Inventory in the Eagle Ford Shale. During 2010, Rosetta successfully delineated Gates Ranch comprised of approximately 26,500 acres in the liquids-rich portion of the Eagle Ford shale in South Texas. In addition, the Company is continuing to successfully explore other areas of its approximate 65,000 acre leasehold position. During 2010, the Eagle Ford shale became the largest producing area for Rosetta. Approximately 53% of the production from this area is comprised of oil, condensate and natural gas liquids (“NGLs”). In the currently weak natural gas market, the Company’s extensive inventory of investment opportunities in the Eagle Ford shale provides higher economic returns than other opportunities in areas previously considered core to the Company’s operations. We expect that the Eagle Ford shale will be a major source of production and reserves for the Company in the future and reflects the success of its transition to an unconventional resources player.

Establish and Test Positions in Emerging Resource Plays. We intend to extend our operational footprint into new core areas within the United States 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 through financial discipline in our leasehold acquisition activities and prudent management of financial and operational resources during the testing phase.

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Divest Lower Return Assets to Fund and Accelerate Our Unconventional Resource Initiatives. In the last two years, Rosetta has established a competitive operating presence in the Eagle Ford shale, one of the most active shale basins in the United States that offers a growing inventory of drilling locations with attractive economics. As a result, we are streamlining our operations and redirecting the proceeds from divestitures of assets that we believe have limited future potential and are no longer core to our long-term growth. In 2010, property sales totaled approximately $90 million. Additional divestitures are planned for 2011.

Apply Technological Expertise. We intend to maintain, further develop and apply the technological expertise that helped us achieve a net drilling success rate of 98% for the year ended December 31, 2010 and helped us establish a major new production base in the Eagle Ford shale. Our definition of drilling success is a well that is producing or capable of production, including wells awaiting pipeline connections to commence deliveries or 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.

Focus 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 unconventional resource play areas where we can achieve efficiencies through economies of scale. As part of our strategy to minimize costs, we have taken aggressive steps to ensure access to transportation and processing facilities and oil field services, specifically within the Eagle Ford shale.

Maintain Financial Flexibility. As of December 31, 2010, we had drawn $130.0 million and had $195.0 million available for borrowing under our revolving credit facility. Additionally, we expect internally generated cash flow and proceeds from asset sales to provide additional financial flexibility to further develop our core assets in the next few years. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our NGLs, crude oil and natural gas production. As part of this strategy, we have entered into a series of hedging arrangements for each year through 2012.

Our Strengths

Our business strategy is to be a successful resource player delivering continued growth and enhanced shareholder value. We believe the following key strengths will enable us to achieve that strategy.

Early Entry and Highly Competitive Position in the Eagle Ford Shale. We hold an asset position in the Eagle Ford shale that we believe will provide the foundation for future growth. As of December 31, 2010, the Company had a 65,000 acre leasehold position with approximately 78% lying in the liquids-rich area of the Eagle Ford shale. Mineral leases were primarily obtained between 2007 and 2010 at a highly competitive average price of approximately $1,036 per acre. For the year ended December 31, 2010, approximately 53% of the Company’s production from the area was comprised of oil, condensate and NGLs, which reduced the Company’s exposure to currently low natural gas prices.

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 to 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 project inventory from our emerging unconventional resource plays.

Operational Control. We operate approximately 99% 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 operations.

Experienced Management and Technical Team. Our executive management team averages 31 years of service in the energy industry and has a broad knowledge of the exploration and production business with specific expertise in the areas where we are operate. With the transition to an unconventional resource player, Rosetta recruited additional management and technical talent with previous experience in finding and developing unconventional resources. This collective ability is a competitive advantage in the execution of our business strategy.

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Our Operating Areas

We own producing and non-producing oil and gas properties in proven or prospective basins that are primarily located in South Texas, including our largest producing area in the Eagle Ford shale, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in Montana. For the year ended December 31, 2010, we drilled 127 gross and 124 net wells, with a net success rate of 98%. The following is a summary of our major operating areas.

South Texas

As of December 31, 2010, we owned approximately 178,000 net acres in South Texas. Our production in South Texas comes from the Eagle Ford shale trend and the Lobo and Olmos fields and averaged 76.3 MMcfe/d for the year ended December 31, 2010, an increase of approximately 28% from the prior year. In 2010, our production from properties outside the Eagle Ford shale averaged 38.0 MMcfe/d, which was 34% below the prior year, reflecting our decision to divert capital away from natural gas producing areas due to low prices to our higher return delineation and development program in the Eagle Ford shale.

Eagle Ford Shale Trend. In only one year, the Eagle Ford shale trend where we hold approximately 65,000 acres, with 50,000 acres located in the liquids-rich area of the play, has become the largest producing area in our portfolio. Our first delineation program in the 26,500 acre Gates Ranch located on the county line between Webb and Dimmit Counties was a geologic and commercial success. In 2010, we drilled 29 gross wells in the Eagle Ford shale, all of which were successful. Our production from the Eagle Ford shale averaged 38.3 MMcfe/d for the year ended December 31, 2010, with approximately 53% of production comprised of oil, condensate and NGLs. During 2010, we also began an exploratory effort in the Light Ranch portion of the Eagle Ford shale in Central Dimmit County. The first well drilled was a discovery.

Lobo Trend. We are a significant producer in the South Texas Lobo trend, with 470 square miles of 3-D seismic and 249 operated producing wells. Our working interests range from 50% to 100%, but most of our acreage is 100% owned and operated. For the year ended December 31, 2010, our average net daily production from the Lobo trend was 27.8 MMcfe/d.

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

Olmos Trend. We acquired a 70% non-operated working interest in 231 gross wells in the Olmos trend of South Texas in late 2008. In 2010, we acquired the remaining 30% working interest and obtained operatorship of these wells. Production from these wells averaged 4.1 MMcfe/d for the year ended December 31, 2010.

California

Historically, the Sacramento Basin has been 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, 2010, we had under lease approximately 54,000 net acres in the Rio Vista Field and other fields in the Sacramento Basin area and our average net daily production from this area was 37.7 MMcfe/d. As part of our strategic decision to focus on the Eagle Ford shale, we entered into an aggrement to sell our Sacramento Basin assets on February 24, 2011. See “Recent Developments” below.

We have announced our intention to sell our position in California as part of our strategic shift to a resource player with a more balanced mix of NGLs, crude oil and natural gas production.

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 in excess of 3.5 Tcfe of natural gas reserves since its discovery in 1936. We currently produce from multiple zones at depths ranging from 2,000 feet to 11,000 feet in the field. The current productive area is approximately ten miles long and nine miles wide.

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Rockies

Since its formation in 2005, Rosetta has produced from three basins in the Rocky Mountains: the DJ Basin in Colorado, San Juan Basin in New Mexico and Greater Green River Basin in Wyoming. During 2010, we produced 18.4 MMcfe/d from these properties. In 2010, we made a strategic decision to divest of our interests in New Mexico and Wyoming in order to focus on the development of the Eagle Ford shale and we completed a divestiture of these interests on December 3, 2010. In 2010, we continued our exploratory initiative in the Southern Alberta Basin in Montana. The play is a westward analog of the industry's Bakken and Three Forks plays of the Williston Basin of Montana and North Dakota. We now control approximately 300,000 net acres in the play, either through option or lease agreements.

DJ Basin, Colorado. As of December 31, 2010, we owned a majority working interest in approximately 69,000 net acres with 160 square miles of 3-D seismic data. For the year ended December 31, 2010, our average net daily production from the DJ Basin was 9.0 MMcfe/d and we drilled 89 gross wells with a 99% success rate. As part of our strategy to further develop the Eagle Ford shale, we entered into an agreement to sell our DJ Basin assets on February 22, 2011. See "Recent Developments" below.

Southern Alberta Basin, Montana. During late 2009 and in the first half of 2010, three exploratory wells were drilled to test the potential of this emerging Devonian shale play. Based on the results from these wells, we launched an eight-well vertical drilling program to further understand the reservoir properties and extent of the play across our leasehold position. As of December 31, 2010, we had drilled six wells. Our evaluations continue and we remain fully committed to testing our holdings in this area where we were an early entrant and hold a competitive position.

Recent Developments

As part of our strategic decision to focus on the development of the Eagle Ford shale, we executed a purchase and sale agreement for $55.0 million on February 22, 2011 for the divestiture of our DJ Basin assets in Colorado. This agreement is subject to due diligence and other termination rights and will be subject to post-closing adjustments. We expect this transaction to close in the second quarter of 2011.

We also executed a purchase and sale agreement with Vintage Petroleum, LLC, for $200.0 million on February 24, 2011 for the divestiture of our Sacramento Basin assets in California. This agreement is subject to due diligence and other termination rights and will be subject to post-closing adjustments. We expect this transaction to close in the second quarter of 2011.

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 tables present certain information with respect to our production data for the periods presented:

	For the Year Ended December 31, 2010			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	6.6	690.0	536.0	14.0
South Texas	11.2	381.0	68.0	13.8
California	13.6	-	27.0	13.8
Rockies	6.6	1.0	21.0	6.7
Gulf Coast	0.5	15.0	47.0	0.9
Other Onshore	0.7	9.0	39.0	1.0
Total	39.2	1,096.0	738.0	50.2

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	For the Year Ended December 31, 2009			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	0.4	12.0	9.0	0.5
South Texas	17.2	549.1	121.9	21.3
California	15.3	-	28.0	15.5
Rockies	6.8	-	20.0	6.9
Gulf Coast	3.3	38.0	135.0	4.3
Other Onshore	1.5	21.0	80.0	2.1
Total	44.5	620.1	393.9	50.6

	For the Year Ended December 31, 2008			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	-	-	-	-
South Texas	18.8	257.8	148.0	21.3
California	15.8	-	31.0	16.0
Rockies	4.5	-	6.0	4.5
Gulf Coast	6.3	158.0	247.4	8.7
Other Onshore	2.3	25.0	114.0	3.1
Total	47.7	440.8	546.4	53.6

(1) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

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.”

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.

As of December 31, 2010, we had an estimated 479.3 Bcfe of proved reserves, including 288.9 Bcf of natural gas, 12,401 MBbls of oil and condensate and 19,326 MBbls of NGLs, of which 51% was proved developed. As of December 31, 2010 and based on the 2010 twelve-month first day of the month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil of $75.96 per Bbl and Henry Hub natural gas of

$4.38 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of $697 million.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2010:

Estimated Proved Reserves at December 31, 2010 (1)(2)

	Developed				Undeveloped					Percent of
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Total (Bcfe) (3)	Total Reserves
Eagle Ford	39.92	4.26	3.26	85.03	102.84	12.85	8.71	232.25	317.3	66 %
South Texas	60.85	2.21	0.32	76.01	-	-	-	-	76.0	16 %
California	42.09	-	0.04	42.32	-	-	-	-	42.3	9 %
Rockies	40.29	-	0.05	40.62	2.13	-	-	2.13	42.8	9 %
Gulf Coast	0.51	0.01	0.01	0.62	-	-	-	-	0.6	0 %
Other Onshore	0.29	-	-	0.29	-	-	-	-	0.3	0 %
Total	183.95	6.48	3.68	244.89	104.97	12.85	8.71	234.38	479.3	100 %

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(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. ("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 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.

(3) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

All of our proved undeveloped reserves at December 31, 2010 are scheduled for development within five years from the date recorded as a proved undeveloped reserve.

As of December 31, 2010, we had proved undeveloped reserves of 234.4 Bcfe, an increase of 148.0 Bcfe relative to December 31, 2009. Significant additions of proved undeveloped reserves resulted primarily from additional proved undeveloped locations in our Eagle Ford shale acreage. Approximately $22.6 million was spent in 2010 associated with the development of 10.3 Bcfe of proved undeveloped reserves. The 10.3 Bcfe includes positive performance revisions of 4.0 Bcfe due to better than expected performance in the Eagle Ford shale. Of the $22.6 million, $18.9 million is related to the Company's development in the Eagle Ford shale that resulted in the development of 9.1 Bcfe (including positive performance revisions).

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, 2010 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.

Internal Control

The preparation of our reserve estimates are 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 internal controls include but are not limited to the following:

– A comparison of historical expenses is made to the lease operating costs in the reserve database.

– Updated capital costs are supplied by Rosetta's Operations Department.

– Internal reserves estimates are reviewed by well and by area by the Corporate Engineering Manager. A variance by well to the previous year-end reserve report and quarter-end reserve estimate is used as a tool in this process.

– Material reserve variances are discussed among the internal reservoir engineers and the Corporate Engineering Manager to insure the best estimate of remaining reserves.

– The internal reserves estimates are reviewed by senior management prior to publication.

The Company's primary reserves estimator is Mark D. Petrichuk, Corporate Engineering Manager. Mr. Petrichuk has 33 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Corporate Engineering Manager maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to and oversees the independent third party engineers for the annual audit of our year-end reserves.

Qualifications of Third Party Engineers

The reserves estimates shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit incorporated herein are Mr. Danny Simmons and Mr. David Nice. Mr. Simmons has been a practicing consulting petroleum engineer at NSAI since 1976. Mr. Simmons is a Registered Professional Engineer in the State of Texas (License No. 45270) and has over 38 years of practical experience in petroleum engineering, with over 35 years experience in the estimation and evaluation of reserves. He graduated from the University of Tennessee in 1973 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Nice has been a practicing consulting petroleum geologist at NSAI since 1998. Mr. Nice is a Certified Petroleum Geologist and Geophysicist in the State of Texas (License No. 346) and has over 26 years of practical experience in petroleum geosciences, with over 12 years experience in the estimation and evaluation of reserves. He graduated from the University of Wyoming in 1982 with a Bachelor of Science Degree in Geology and in 1985 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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2010 Capital Expenditures

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31, 2010	2009 (In thousands)	2008
Capital expenditures	$ 268,578	$ 90,524	$ 197,026
Leasehold	49,328	22,066	57,261
Acquisitions	5,986	3,624	62,570
Delay rentals	1,193	1,683	1,451
Geological and geophysical/seismic	518	8,558	4,571
Exploration overhead	7,775	4,806	7,140
Capitalized interest	4,017	1,174	1,422
Other corporate	2,042	2,942	3,046
Total capital expenditures	$ 339,437	$ 135,377	$ 334,487

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, 2010. "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 Gross		Productive Wells Net	
	Gross	Net	Gross	Net	Natural Gas	Oil	Natural Gas	Oil
Eagle Ford	104,951	62,875	2,310	2,284	22	-	21	-
South Texas	41,325	36,435	67,606	66,042	431	2	400	2
California	16,875	9,463	53,504	44,188	140	-	131	-
Rockies (1)	148,870	135,593	20,490	18,156	208	2	205	1
Gulf Coast	5,000	2,500	12,532	5,660	1	-	-	-
Other Onshore	2,904	1,341	-	-	9	1	3	-
Total	319,925	248,207	156,442	136,330	811	5	760	3

(1) Excludes approximately 228,000 net undeveloped acres under exploration option in the Southern Alberta Basin.

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

The following table shows our interest in undeveloped acreage as of December 31, 2010 that is subject to expiration in 2011, 2012, 2013 and thereafter:

2011		2012		2013		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
77,684	66,722	48,037	40,525	15,854	19,649	134,975	120,403

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 production.

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	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2010	10.0	-	10.0	115.0	2.0	117.0
2009	7.0	-	7.0	30.0	6.0	36.0
2008	3.0	1.0	4.0	160.0	20.0	180.0

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
2010	9.9	-	9.9	112.4	2.0	114.4
2009	6.1	-	6.1	23.4	6.0	29.4
2008	1.9	1.0	2.9	132.7	15.9	148.6

At December 31, 2010, we had two wells in process. These wells were located in the South Texas Eagle Ford shale where we owned a 90% working interest in one well and a 100% working interest in the remaining 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 year ended December 31, 2010, natural gas sales from dedicated production comprised approximately 35% of our overall natural gas sales for the Company.

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 is 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, 2010, we had two major customers, CES and Shell Trading (US) Company, which accounted for approximately 48% and 16%, respectively, 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.

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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.

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 the location, 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 a package of four bills, which the governor signed, and introduced an $11.14 billion bond measure to be voted on by the California voters in the November 2012 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 the Company's 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 September 2009, the U.S. House of Representatives passed a comprehensive clean energy and climate bill (H.R. 2454, also known as "Waxman-Markey"). The U.S. Senate is working on a variety of proposed climate bills, including the American Power Act of 2010 (proposed by Senators Kerry and Lieberman). These bills or new legislation may be considered by the current Congress. In substance, most legislative proposals contain 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") has begun to regulate greenhouse gas emissions. 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. Finally, on November 8, 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules require data collection beginning in 2011 and reporting beginning in 2012. Some of our facilities are subject to these rules. On May 12, 2010, the EPA issued a new "tailoring" rule, which proposed and imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of carbon dioxide equivalent emissions. This rule does not currently affect our operations but may as our operations grow. Finally, the EPA is considering additional rulemaking to apply these requirements to broader classes of emission sources by 2012, which may apply to some of our facilities. 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 operations. If this legislation is passed, it would impose additional requirements on our hydraulic fracturing operations and 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 alleged 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 threatened referral of the matter to the Wyoming Attorney General for "appropriate penalties," which could have included civil penalties or injunctive relief. In the fourth quarter of 2010, we settled the Wyoming DEQ Notice of Violation for a total of $25,000 and the required permits were obtained.

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 material loss not fully covered by insurance could have an 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.

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 2010, we filed estimates of our oil and gas reserves as of December 31, 2009 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, 2009. For information concerning proved natural gas and crude oil reserves, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

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Employees

As of February 18, 2011, we had 168 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines, as needed. 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 Securities Exchange Act of 1934, as amended, 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

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 of 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 a variety of factors beyond our control, such as:

– Domestic and foreign supply of oil and natural gas;

– Price and quantity of foreign imports of oil and natural gas;

– Actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;

– Consumer demand;

– The impact of energy conservation efforts;

– 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;

- The availability of refining capacity;
- Weather conditions and natural disasters;
- Technological advances affecting oil and natural gas production and 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 relation to each other. Our revenue, profitability, and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

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- Negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;

- Reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and

- Result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

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

Several factors could adversely impact our ability to implement our strategy as an onshore unconventional resource player, including: (i) a sustained downturn of commodity prices, (ii) a lack of inventory potential within existing resource plays, (iii) an inability to attract and retain the personnel necessary to implement an unconventional resource business model, and (iv) a lack of access to capital.

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

Fiscal 2008 and 2009 periods were periods of severe volatility and disruption in the economy and capital markets. While there were signs in 2010 that the economy may be improving, the potential remains for further volatility and disruption. During 2008 and 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.

Potential 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. Borrowings under our existing revolving credit facility are subject to the maintenance of a borrowing base, which is subject to semi-annual and other adjustments. In the event that our borrowing base is reduced, outstanding borrowings in excess of the revised borrowing base will be due and payable immediately and 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 may require us to reduce our capital expenditures, 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.

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. 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.

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 to CES all of our existing and future production from our California leases in production as of May 1, 2005 at market prices. For the year ended December 31, 2010, natural gas sales from dedicated production comprised approximately 35% of our overall natural gas sales for the Company. 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, 2010 would be approximately $1.0 million.

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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.

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 covenants. 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 lender 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.

Our revolving credit facility also limits the amounts we can borrow to a borrowing base amount, as determined by the lenders in accordance with the credit agreement. Outstanding borrowings in excess of the borrowing base will be required to be repaid immediately, or we will be required to pledge other oil and natural gas properties as additional collateral.

Our exploration and development activities may not be commercially successful.

Exploration and development activities involve numerous risks, including the risk that no commercially productive quantities of oil or natural gas 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:

– Reductions in oil and natural gas prices;

– Unexpected drilling conditions;

– Pressure or irregularities in formations;

– Equipment failures or accidents;

– Adverse weather conditions;

– Compliance with environmental and other governmental regulations;

– Environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;

– 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;

– Limitations in takeaway capacity or the market for oil and natural gas;

– Increase in severance taxes; and

– Lost or damaged oilfield development and services tools.

Our decisions to purchase, explore, develop and exploit prospects or properties depend, in part, on data obtained through geological and geophysical analyses, production data and engineering studies, the results of which are uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying potentially productive hydrocarbon traps and geohazards. 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.

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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. 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, 2010 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 $75.96 per Bbl and the twelve-month first day of the month historical average Henry Hub gas prices adjusted for basis and quality differentials of $4.38 per MMbtu. 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 Bureau of Ocean Energy Management, Regulation and Enforcement, or "BOE," (formerly known as the Minerals Management Service) of the U.S. Department of the Interior, 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.

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 standardized measure 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 the standardized measure of future net cash flows.

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

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, of 2008 and of $379.5 million in the first quarter of 2009. We did not record any write-down or impairment for the year ended December 31, 2010. Due to the volatility of commodity prices, however, should natural gas prices decline in the future, it is possible that 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. 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.

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Government laws and regulations can change.

Our activities are subject to federal, state, regional and local laws and regulations. Extensive laws, regulations and rules regulate 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, production levels, royalty obligations, price levels, environmental requirements, and other aspects of our business, including our general profitability. We are unable to predict changes to existing laws and regulations. For example, in response to the April 2010 fire and explosion onboard the semisubmersible drilling rig Deepwater Horizon, leading to the oil spill in the Gulf of Mexico, the BOE has limited certain drilling activities in the U.S. Gulf of Mexico. The BOE may also issue new safety and environmental guidelines or regulations for drilling in the U.S. Gulf of Mexico, and potentially in other geographic regions, and may take other steps that could increase the costs of exploration and production. This incident could also result in drilling suspensions or other regulatory initiatives in other areas of the U.S. and abroad. Furthermore, the U.S. Environmental Protection Agency has recently focused on public concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities. This renewed focus could lead to additional federal and state regulations affecting the oil and gas industry. Additional regulations or other changes to existing laws and regulations could significantly impact our business, results of operations, cash flows, financial position and future growth.

Our business requires a 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. 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. Our concentration of operations in certain geographic areas, such as the Eagle Ford shale, increases this risk and the potential impact upon us. When that also occurs, we are unable to realize revenue from those wells until the production can be tied to a pipeline or 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.

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. Our competitors include major and large independent oil and natural gas companies that possess financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties at a lower cost and more quickly 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. 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.

Our strategy as an onshore unconventional resource player has resulted in operations concentrated in one geographic area and increases our exposure to many of the risks enumerated herein.

Currently our operations are highly concentrated in South Texas, primarily in the Eagle Ford shale. This concentration increases the potential impact that many of the risks stated herein may have upon our ability to perform. For example, we have greater exposure to regulatory actions impacting Texas, natural disasters in the geographic area, competition for equipment, services and materials available in the area and access to infrastructure and markets.

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.

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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 natural 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 the Eagle Ford shale of Texas, California or 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 (particularly in California), mud slides, and flooding;

– Pollution; and

– Releases of toxic gas.

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. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, our insurance policies provide limited coverage for losses or liabilities relating to sudden and accidental pollution, but not for other types of pollution. Our insurance might be inadequate to cover our liabilities. Our energy package is written on reasonably standard terms and conditions that are generally available to the exploration and production industry. 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 in the future as the insurance industry adjusts to difficult exposures 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 for a risk at a time when we do not have liability insurance, then our business, financial position, results of operations and cash flows could be materially adversely affected.

Competition and regulation of hydraulic fracturing services could impede our ability to develop our shale plays.

The unavailability or high cost of high pressure pumping services (or hydraulic fracturing services), chemicals, proppant, water, and related services and equipment could limit our ability to execute our exploration and development plans on a timely basis and within our budget. Our industry is experiencing a growing emphasis on the exploitation and development of shale gas and shale oil resource plays which are dependent on hydraulic fracturing for economically successful development. Hydraulic fracturing in shale plays requires high pressure pumping service crews. A shortage of service crews or proppant, chemical, or water, especially if this shortage occurred in South Texas or the Rockies, could materially and adversely affect our operations and the timeliness of executing our development plans within our budget. There is significant regulatory uncertainty as some states have begun to regulate hydraulic fracturing and the United States Environmental Protection Agency and United States Congress are investigating the impact of hydraulic fracturing on drinking water sources, which could affect the current regulatory jurisdiction of the states and increase the cycle times and costs to receive permits, delay or possibly preclude receipt of permits in certain areas, impact water usage and waste water disposal and require chemical additives disclosures.

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 EPA 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. In November 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules require data collection beginning in 2011 and reporting beginning in 2012. Some of our facilities are subject to these rules. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of other 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 property acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make property acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy includes acquiring oil and natural gas properties. 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;

– Potential lack of operating experience in the geographic market where the acquired properties are located;

– An increase in our expenses and working capital requirements;

– The validity of our assumptions about reserves, future production, revenues, capital expenditures, and operating costs, including synergies;

– A decrease in our liquidity by using a significant portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;

– A significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

– The assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which our indemnity is inadequate; and

– The incurrence of other significant charges, such as impairment of oil and natural gas properties, asset devaluation, or restructuring charges.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully access their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

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

We have entered into oil, natural gas, and NGL price hedging arrangements with respect to a portion of our expected production through 2012. These hedging transactions may limit our potential revenue if oil, natural gas, and NGL prices were to rise substantially over the price established by the hedge. As of December 31, 2010, approximately 88% of total hedged natural gas transactions represented hedged prices of commodities at the PG&E Citygate and Houston Ship Channel, 100% of hedged crude oil transactions represented hedged prices of crude oil at the West Texas Intermediate on the NYMEX and approximately 52% of the total hedged NGL transactions represented hedged NGL prices at Mont Belvieu Propane (Non-TET) OPIS. 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.

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

Our commodity derivative transactions expose us to credit risk in the event of default by our counterparties that include commercial banks, investment banks, insurance companies, other investment funds and other institutions. 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 may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. In addition, if any lender under our revolving 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 revolving credit facility. Currently, no single lender in our credit facility has commitments representing more than 11% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Reform Act. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the act. The new requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in natural gas, oil and NGL commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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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 2012 budget proposal, released by the White House on February 14, 2011, 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. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies, which, if enacted, would negatively affect our financial condition and results of operations. The passage of any legislation as a result of the budget proposal 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.

Item 3. Legal Proceedings

We are party to various legal and regulatory proceedings arising in the ordinary course of business. 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 for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the consolidated financial statements.

Item 4. Removed and Reserved

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 the high and low sale prices of our common stock for the periods indicated:

	2010			2009	
	High	Low		High	Low
January 1 - March 31	$ 25.20	$ 17.21	January 1 - March 31	$ 8.37	$ 3.52
April 1 - June 30	26.92	18.39	April 1 - June 30	10.17	4.81
July 1 - September 30	24.18	18.77	July 1 - September 30	15.60	7.08

October 1 - December 31	38.98	23.02	October 1 - December 31	20.62	12.35

The number of shareholders of record on February 18, 2011 was approximately 190. 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 limitations imposed by our lenders or by any of our investors, as well as other factors the board of directors may deem relevant. The declaration and payment of dividends is restricted by our existing revolving credit facility, the indenture governing our 9.500% Senior Notes due 2018 ("Senior Notes"), and our existing term loan. Future agreements may also restrict our ability to pay dividends.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2010:

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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	3,054	$ 24.02	-	-
November 1 - November 30	21,206	24.03	-	-
December 1 - December 31	21,028	36.22	-	-

(1) All of the shares were surrendered by our employees and directors 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, 2010. 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 listing of its common stock on The NASDAQ), 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.

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

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	2/13/2006 (1)	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
ROSE	$ 100.00	$ 98.26	$ 104.37	$ 37.26	$ 104.84	$ 198.11
S&P 500	100.00	113.86	120.12	75.67	95.70	110.12
S&P 400 E&P	100.00	103.24	149.13	67.84	120.86	173.08

(1) February 13, 2006 was the first full trading day following the Company's listing of its common stock on The NASDAQ.

Item 6. Selected Financial Data

The following selected financial data should be read 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.

	Year Ended December 31,				
	2010	2009 (1)	2008 (1)	2007	2006
	(In thousands, except per share data)				
Operating Data:					
Total revenues	$308,430	$293,951	$499,347	$363,489	$271,763
Net income (loss)	19,046	(219,176)	(188,110)	57,205	44,608
Net Income (loss) per share:					
Basic	0.37	(4.30)	(3.71)	1.14	0.89
Diluted	0.37	(4.30)	(3.71)	1.13	0.88
Cash dividends declared per common share	-	-	-	-	-
Balance Sheet Data (At the end of the Period)					
Total assets	997,309	879,584	1,154,378	1,357,214	1,219,405
Long-term debt	350,000	288,742	300,000	245,000	240,000
Stockholders' equity	528,816	493,095	726,372	872,955	822,289

(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.

We did not declare or pay any cash dividends for any of the periods indicated in the table above.

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

Overview

During 2010, Rosetta began to realize benefits from its transformation to an unconventional resource player. Most notably, we built a portfolio of high-quality shale assets with project inventory offering visible and sustainable growth.

Our success was the result of the initiative that we began three years ago to employ personnel with the appropriate competencies to execute an unconventional resource-driven business model. We were an early entrant into the Eagle Ford shale, one of the most competitive shale plays in the industry and one of the first participants to develop a significant leasehold position and conduct comprehensive exploratory evaluations in that play. Our efforts were coupled with a conservative fiscal approach and a focus on cost control and efficiency.

We believe that our 2010 performance as an unconventional resource player as compared to our 2009 performance serves as tangible evidence that we are now a stronger exploration and production company positioned to further increase inventory to drive significant growth. The following are some of our major achievements in 2010:

- Rosetta established a major new base of production and reserves in the Eagle Ford shale in South Texas. During 2010, we successfully delineated a 26,500 acre position within Gates Ranch, successfully drilling 25 wells and completing 16 wells. We believe that we have identified a significant inventory of investment opportunities. This portfolio should lower our overall cost structure and deliver positive returns. During 2010, we overcame numerous operating obstacles resulting from increasing demands for service equipment and infrastructure and entered into firm long-term natural gas agreements for transportation and processing capacity that will meet our current and projected production from the area for up to ten years. In the third quarter of 2010, we announced the Light Ranch field discovery in another section of our Eagle Ford shale holdings, which further expands our drilling inventory.

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- We shifted our production portfolio to a more balanced mix of natural gas liquids, crude oil and natural gas. This reduces our exposure to current low natural gas prices and allows us to take advantage of cyclical swings in energy commodity pricing. For the month ended December 31, 2010, more than 30% of our production was from oil and NGLs and that amount will increase as Rosetta brings on-line more production from the Eagle Ford shale. Approximately 56% of reserves that we have discovered in the Gates Ranch are liquids.

- Our annual production rate averaged 138 MMcfe/d and we exited the year with a production rate of 157 MMcfe/d. Of this exit rate, 54% was from the Eagle Ford shale and exemplifies the shift in our production base to unconventional resources during the year. In addition, we drilled 100% successful exploratory wells in the Eagle Ford shale in 2010 that contributed to reserve growth of 36%.

- We continue to divest our legacy assets that we believe do not offer the same investment opportunities or rate of returns as our unconventional resources. During 2010, we sold assets located in Arkansas, Oklahoma, Mississippi, Texas, Louisiana, New Mexico and Wyoming for approximately $90.0 million with the monies redeployed into developing our positions. We believe the divestiture of these assets will decrease our cost structure through lower general and administrative expenses and lower operating costs. In 2011, we expect to complete the sales of our properties in the DJ Basin in Colorado and our holdings in the Sacramento Basin in California.

- We retained our focus on financial flexibility as we continuously monitored our capital program results and diverted spending away from legacy natural gas producing areas to more promising opportunities offered by our high-return, high-value resource assets. We refinanced our existing portfolio of debt through our Senior Notes offering and repayments under our revolving credit facility and term loan. We hedged selectively during the year to ensure stable future cash flows and balanced our capital spending program with asset sales and cash on hand.

- We continued our exploratory evaluations of our large acreage position in the Southern Alberta Basin in Northwest Montana. In 2010, we drilled four delineation wells in the area. Our assessment to date confirms oil hydrocarbons in place. We are encouraged by what we are learning and intend to fully test our position.

Our business goals for 2011 are based on an announced capital program of $360.0 million, subject to program results and timing. We enter 2011 with a project inventory base that is more than double the size of the previous year with a lower overall total cost structure than our previous holdings. As we move forward with the development of our inventory, we expect to deliver long-term positive returns. More than 90% of our planned spending will be allocated to the development of our Eagle Ford shale assets, primarily in the Gates Ranch area. Approximately 40 completions are planned with a fracture stimulation agreement in place to handle the increased activity. We have contracts in place for firm transportation and processing up to 205 MMcf/d of gross wellhead production with 115 MMcf/d of capacity available no later than the fourth quarter of 2011 and total contractual capacity reached by 2013. Our capital program reflects the impact of planned asset sales in the DJ Basin in Colorado and the Sacramento Basin in California. It also includes funds for the continued exploration of the Southern Alberta Basin where we plan to drill another five vertical wells by early 2011. We remain encouraged by the results of our drilling program and expect to add horizontal wells during 2011. At this time, we believe that we have sufficient internal investment opportunities to grow the Company without acquiring additional properties. However, we continue to evaluate opportunities that fit our business model and our strategic and economic objectives.

While 2010 was a successful year for Rosetta, we recognize that there are risks inherent to our industry and operating environment that could impact our ability to meet future goals. Our business model takes into account these threats and we continually work to overcome potential risks to our ability to achieve our stated growth objectives and build our asset base. We have reduced our exposure to weak natural gas commodity prices by diversifying our production base to a higher percentage of natural gas liquids and crude oil, which continue to trade at more profitable levels. Heightened industry activity from other participants in the Eagle Ford shale, our largest producing area, led to some curtailments of production in 2010. We have taken aggressive steps to ensure access to transportation and processing facilities and oil field services in the area. However, we cannot completely control all external factors that could impact our operating environment. Given the early stage of the Southern Alberta Basin play, there are still significant risks associated with an exploration program of this magnitude. Identifying and responding effectively to potential threats in the marketplace is an important part of managing our business.

As part of our strategy to streamline our business, we announced the closing of our Denver office and the reorganization of Houston personnel. As of December 31, 2010, we had incurred approximately $3.5 million of costs related to this reorganization and expect the reorganization to be completed by December 31, 2011. While all future costs associated with the reorganization cannot be fully anticipated, we estimate that we will incur total costs of approximately $5.0 million. We believe the consolidation of our technical resources to Houston will enable us to capitalize on the dynamics and efficiencies of operating in a central location.

Our 2011 capital budget of $360.0 million takes into account the number of high-return opportunities afforded by our position in the Eagle Ford shale. It is our intention to maintain our current debt levels and to continue to redeploy proceeds from planned asset sales to the development of our Eagle Ford shale properties. We are confident that we can execute our capital program based on asset sale proceeds and internally generated cash flows plus cash on hand. We monitor our liquidity situation continuously and respond prudently to changing market conditions, commodity prices or service costs. In the event we encounter a situation in which there is not sufficient internal funds to meet projected funding of our 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.

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Our borrowing base under our revolving credit facility was confirmed by our lenders in October 2010 at $365.0 million. According to our agreement, the borrowing base was adjusted in December 2010 to $325.0 million after the successful divestitures of our Pinedale and San Juan assets. As of December 31, 2010, we had $195.0 million of available borrowing capacity under our revolving credit facility. There has not been any indication that draws under our credit facility will be restricted below current availability. The next redetermination is scheduled to begin in April 2011. Our ability to raise additional capital depends on the state of the financial markets that are subject to change depending upon 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. We work closely with our lenders to stay abreast of market and creditor conditions. Our capital expenditures are primarily in areas where we act as operator and have 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 $308.4 million on total volumes of 50.2 Bcfe for the year ended December 31, 2010. Operating income for the year ended December 31, 2010 was $71.5 million and included depreciation, depletion and amortization ("DD&A") expense of $116.6 million, lease operating expense of $51.1 million and $14.1 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, 2010 was comprised of interest expense (net of capitalized interest) on our long-term debt offset by interest income on short-term cash investments.

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,		
	2010	2009	2008
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas sales	$ 208,688	$ 250,684	$ 398,268
Oil sales	54,542	21,763	55,736
NGL sales	45,200	21,504	45,343
Total revenues	$ 308,430	$ 293,951	$ 499,347
Production:			
Gas (Bcf)	39.2	44.5	47.7
Oil (MBbls)	738.0	393.9	546.4
NGLs (MBbls)	1,096.0	620.1	440.8
Total equivalents (Bcfe)	50.2	50.6	53.6
$ per unit:			
Avg. gas price per Mcf, excluding hedging	$ 4.50	$ 3.91	$ 8.74
Avg. gas price per Mcf	5.32	5.63	8.35
Avg. oil price per Bbl	73.91	55.25	102.00
Avg. NGL price per Bbl	41.24	34.68	102.87
Avg. revenue per Mcfe	6.14	5.81	9.32

Revenues

Our revenues are derived from the sale of our natural gas, oil and NGL 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, 2010 Compared to the Year Ended December 31, 2009

Total revenue for the year ended December 31, 2010 was $308.4 million, which was an increase of $14.4 million, or 5%, from the year ended December 31, 2009. Excluding the effects of hedging, approximately 64%, 20% and 16% of revenue for the year ended December 31, 2010 was attributable to natural gas sales, oil and NGL sales respectively, as compared to 80%, 10%, and 10%, respectively, for 2009.

Natural Gas. Including the realized impact of derivative instruments for the year ended December 31, 2010, natural gas revenue decreased by 17%, or $42.0 million, from the comparable period in 2009. Of this decrease, $44.1 million was attributable to the effect of gas hedging activities and $20.6 million was attributable to decreased volumes. This decrease was offset by an increase of $22.7 million attributable to higher average realized prices in 2010. The average realized natural gas price, including the effects of hedging, decreased 6%, or $0.31, to $5.32 per Mcf for the year ended December 31, 2010 as compared to $5.63 per Mcf for the same period in 2009. Natural gas production volumes decreased overall by 12%, or 5.3 Bcf, for the year ended December 31, 2010, primarily due to asset divestitures of non-core properties, the suspension of drilling programs in areas that produce primarily from dry gas reservoirs and the natural decline in our non-core Gulf Coast properties.

Crude Oil. For the year ended December 31, 2010, oil revenue increased by 150%, or $32.7 million, primarily due to the increase of $18.66 per Bbl in the average realized oil price from $55.25 per Bbl for the year ended December 31, 2009 to $73.91 per Bbl for the year ended December 31, 2010. Oil volumes also increased by 87%, or 344.1 MBbls, to 738.0 MBbls for the year ended December 31, 2010 from 393.9 MBbls for the year ended December 31, 2009. The increase in oil production volumes was due to our success in the Eagle Ford shale.

NGLs. For the year ended December 31, 2010, NGL revenue increased by 110%, or $23.7 million, primarily due to the increase of $6.56 per Bbl in the average realized NGL price from $34.68 per Bbl for the year ended December 31, 2009 to $41.24 per Bbl for the year ended December 31, 2010. NGL volumes increased by 77%, or 475.9 MBbls, to 1,096.0 MBbls for the year ended December 31, 2010 from 620.1 MBbls for the year ended December 31, 2009. The increase in NGL production volumes was due to our success in the Eagle Ford shale, reflecting our shift in strategy to a more liquids-based production mix.

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 was a decrease of $205.4 million, or 41%, from the year ended December 31, 2008. Excluding the effects of hedging, approximately 80%, 10% and 10% of revenue for the year ended December 31, 2010 was attributable to natural gas sales, oil and NGL sales respectively, as compared to 80%, 11%, and 9%, respectively, for 2009.

Natural Gas. Including the realized impact of derivative instruments for the year ended December 31, 2009, natural gas revenue decreased by 37%, or $147.6 million, from the comparable period in 2008. Of this decrease, $27.1 million was attributable to decreased volumes and $120.5 million was 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. 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 a natural decline in our non-core Gulf of Mexico properties, the suspension of drilling programs during 2009 in areas where we were active during 2008 and 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 economic 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 realized 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 a 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 realized 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.

Operating Expenses

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

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	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per unit amounts)		
Lease operating expense	$ 51,085	$ 60,773	$ 55,694
Production taxes	5,953	6,131	13,528
Depreciation, depletion and amortization	116,558	121,042	198,862
Impairment of oil and gas properties	-	379,462	444,369
General and administrative costs	56,332	46,993	52,846
$ per unit:			
Avg. lease operating expense per Mcfe	$ 1.02	$ 1.20	$ 1.04
Avg. production taxes per Mcfe	0.12	0.12	0.25
Avg. DD&A per Mcfe	2.32	2.39	3.71
Avg. production costs per Mcfe (1)	3.34	3.59	4.75
Avg. production costs per Mcfe (2)	3.15	3.31	4.53
Avg. General and administrative costs per Mcfe	1.12	0.93	0.99
Avg. General and administrative costs per Mcfe, excluding stock-based compensation	0.84	0.78	0.85

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

(2) Production costs per Mcfe includes lease operating expense and DD&A and excludes production and ad valorem taxes.

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 for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the consolidated financial statements.

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Lease Operating Expense. Lease operating expense decreased $9.7 million for the year ended December 31, 2010 as compared to the same period for 2009. This overall decrease was primarily due to cost control measures and asset divestitures. Lease operating expense included workover costs of $0.04 per Mcfe, ad valorem taxes of $0.19 per Mcfe and insurance of $0.03 per Mcfe for the year ended December 31, 2010 as compared to workover costs of $0.08 per Mcfe, ad valorem taxes of $0.29 per Mcfe and insurance of $0.03 per Mcfe for the same period in 2009.

Production Taxes. Production taxes as a percentage of unhedged natural gas, oil and NGL sales were 2.2% for the year ended December 31, 2010 as compared to 2.8% for the year ended December 31, 2009. This decrease was primarily due to certain production tax credits in the State of Texas.

Depreciation, Depletion, and Amortization. DD&A expense decreased $4.4 million for the year ended December 31, 2010 as compared to the same period for 2009. The decrease was due to a 1% decrease in total production and a lower DD&A rate for 2010 compared to 2009 due to the full cost ceiling test impairment charges recognized in the first quarter of 2009, which decreased the full cost pool. The DD&A rate for the year ended December 31, 2010 was $2.32 per Mcfe while the rate for the year ended December 31, 2009 was $2.39 per Mcfe.

Impairment of Oil and Gas Properties. Based on quarterly ceiling test computations using a twelve-month average price computed as an average of first day of the month prices, adjusted for hedges of oil and gas, we were not required to record a write-down at December 31, 2010 and no write-down occurred during the twelve months ended December 31, 2010. However, based on 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 we recorded a pre-tax, non-cash impairment expense of $379.5 million.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead costs of $7.8 million, increased by $9.3 million for the year ended December 31, 2010 as compared to the same period for 2009. The increase in general and administrative costs was primarily related to a $6.7 million increase in stock-based compensation due to the increased stock price, a $4.5 million increase in salaries, wages and bonuses, a $2.5 million increase in benefit costs offset by an increase of $1.5 million in billable field personnel, a $2.6 million increase in capitalizable geological and geophysical expenses and $0.3 million of other administrative costs.

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 was 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 included 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 unhedged natural gas, oil and NGL sales were 2.8% for the year ended December 31, 2009 as compared to 2.6% for the year ended December 31, 2008. This increase was the result of production tax credits for the year ended December 31, 2008 as compared to the same period for 2009.

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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 was 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 on 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 we recorded a pre-tax, non-cash impairment expense of $379.5 million. The application of the new SEC guidance did not impact the ceiling test for the year ended 2009. Based on 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 we recorded a pre-tax, non-cash impairment expense of $444.4 million.

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 2009 was 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.

Total Other Expense

Total other expense includes Interest expense, net of interest capitalized, Interest income and Other income/expense, net which increased $7.6 million for the year ended December 31, 2010 as compared to the same period in 2009. The increase in Total other expense was primarily due to an increase in interest expense associated with higher amounts of outstanding debt. Long-term debt outstanding as of December 31, 2010 was $61.3 million higher as compared to December 31, 2009. The weighted average interest rate for the twelve months ended December 31, 2010 was 7.06% compared to 5.18% for the same period in 2009. This increase in the weighted average interest rate was primarily due to the higher interest rate associated with the Senior Notes.

Other expense decreased $7.3 million for the year ended December 31, 2009 as compared to the same period in 2008. The decrease in other expense was 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 our credit facilities and increased amortization of deferred loan fees and original issue discount related to our credit facilities during the first quarter of 2009.

Provision for Income Taxes

Our 2010 income tax expense was $26.5 million. For the year ended December 31, 2010, the effective tax rate was 58.2% compared to the effective tax rate of 36.5% for the year ended December 31, 2009 and 37.5% for the year ended December 31, 2008. 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, the non-deductibility of certain incentive compensation and a valuation allowance against certain state deferred tax assets.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the 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. As of December 31, 2010, the Company had a deferred tax asset of $142.7 million, compared to a deferred tax asset of approximately $169.7 million at December 31, 2009, resulting primarily from the difference between the book basis and tax basis of our oil and natural gas properties and net operating loss carryforwards. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards.

In connection with the planned asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded that it is more likely than not that the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances have been established for these items as well as state NOLs in other jurisdictions in which the Company previously operated but has since divested of operating assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

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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 commodity prices. The effects of these derivative transactions on our natural gas sales are discussed above under "Results of Operations – Revenues – Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009 - Natural Gas" and "Results of Operations – Revenues – Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008 - Natural Gas." The majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels. 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 Credit Facility. Our amended and restated revolving credit agreement (the "Restated Revolver") provides for a senior secured revolving line of credit of up to $600.0 million and matures on 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 as well as asset divestitures. 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.

Our borrowing base was confirmed by our lenders in October 2010 at $365.0 million. In accordance with our agreement, the borrowing base was adjusted in December 2010 to $325.0 million after the successful divestitures of our Pinedale and San Juan assets. As of December 31, 2010, we had $195.0 million of available borrowing capacity under our Restated Revolver. 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 our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants as defined in our credit agreement. The terms of the credit agreement require us to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require us to maintain a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, 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, 2010, our current ratio was 3.5 and the leverage ratio was 1.7. 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, 2010. As of February 18, 2011, we had $130.0 million outstanding, with $195.0 million available for borrowing under the Restated Revolver. The borrowing base will be subject to further adjustment pending the potential DJ Basin and Sacramento Basin divestitures.

Second Lien Term Loan. Our amended and restated term loan (the “Restated Term Loan”) matures on October 2, 2012. On April 15, 2010, we repaid $80.0 million of variable rate borrowings outstanding under the Restated Term Loan, which bore interest at LIBOR plus 8.5% with a LIBOR floor of 3.5%. In connection with the repayment, we paid an early termination premium of $1.3 million. In accordance with authoritative guidance for derivative instruments and hedging activities, we evaluated the LIBOR floor as an embedded derivative and concluded that because the terms were clearly and closely related to the debt instrument, it did not represent an embedded derivative to be accounted for separately. As of December 31, 2010, we had $20.0 million of fixed rate borrowings outstanding bearing interest at 13.75% under the Restated Term Loan. The loan is collateralized by second priority liens on substantially all of the Company’s assets. We are subject to the financial covenants as defined in our term loan agreement. We are required under the term loan agreement to maintain a minimum reserve ratio of our total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require us to maintain a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. At December 31, 2010, our reserve coverage ratio was 2.2 and the leverage ratio was 1.7. In addition, the Company is subject to covenants, including limitations on 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, 2010. We also have the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. The Senior Notes were issued under an indenture (the “Indenture”) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit our ability to, among other things, incur additional indebtedness; pay dividends on our capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under our Restated Revolver and $80.0 million of variable rate borrowings outstanding under our Restated Term Loan, and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, we exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

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As of December 31, 2010, we had total outstanding borrowings of $350.0 million and for the year ended December 31, 2010, our weighted average borrowing rate was 7.06%.

Working Capital

At December 31, 2010, we had a working capital surplus of $22.8 million as compared to a working capital surplus of $45.7 million at December 31, 2009. 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 2010 was largely caused by the increases in our receivables and derivative instruments. As of December 31, 2010, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $41.6 million and $19.1 million, respectively. In addition, the Accrued liability balance included in the working capital liability was approximately $57.0 million as of December 31, 2010.

Cash Flows

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Cash flows provided by operating activities	$ 176,861	$ 160,501	$ 374,719
Cash flows used in investing activities	(251,621)	(123,865)	(393,070)
Cash flows (used in) provided by financing activities	55,138	(18,235)	57,990
Net (decrease) increase in cash and cash equivalents	$ (19,622)	$ 18,401	$ 39,639

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, 2010.

Cash flows provided by operating activities increased by $16.4 million for the year ended December 31, 2010 as compared to the same period for 2009. This increase was largely due to higher oil, NGL and natural gas prices and increased oil and NGL production during 2010 compared to 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 was 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.

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

Cash flows used in investing activities increased by $127.8 million for the year ended December 31, 2010 as compared to the same period for 2009. The increase was primarily attributable to increased expenditures of $187.9 million for purchases to develop oil and gas properties offset with a decrease in investing activities of $63.6 million due to asset sales. For the year ended December 31, 2010, we incurred approximately $339.4 million in capital expenditures as compared to approximately $135.4 million for the year ended December 31, 2009. During the year ended December 31, 2010, we participated in the drilling of 127 gross wells as compared to the drilling of 43 gross wells for the year ended December 31, 2009.

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 $135.4 million in capital expenditures as compared to $334.5 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.

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Financing Activities. The primary drivers of cash provided by (used in) financing activities are borrowings and repayments under the Restated Revolver and equity transactions associated with the exercise of stock options, and the acquisition of treasury shares from employees and directors to pay tax withholding upon the vesting of restricted stock.

Cash flows provided by financing activities increased by $73.4 million for the year ended December 31, 2010 as compared to the same period for 2009. The net increase was primarily related to the borrowings under the Restated Revolver of $64.0 million during the year ended December 31, 2010, the net impact of the $200.0 million issuance of our Senior Notes and repayment of $80.0 million under the Restated Term Loan and $124.0 million under the Restated Revolver.

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 was primarily related to payments of $40.0 million made in 2009 under 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.

Commodity Price Risk, Interest Rate Risk and Related Hedging Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL 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 enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of natural gas, oil and NGL fixed price swaps and costless collars for each year through 2012. Our fixed price swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs, and natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected production from existing wells at inception of the hedge instruments.

Borrowings under our Restated Revolver mature on July 1, 2012 and bear interest at a LIBOR-based rate. To mitigate our exposure to rising interest rates, we entered into a series of interest rate swap agreements that expired in December 2010. We may enter into additional interest rate swap agreements in the future to mitigate interest rate risk if the costs are not prohibitive.

The following table sets forth the results of commodity fixed price and costless collars and interest rate swap derivative settlements:

	For the Year Ended December 31,		
	2010	2009	2008
Natural Gas			
Quantity settled (MMBtu)	14,645,000	20,856,465	26,684,616
Increase (decrease) in natural gas sales revenue (In thousands)	$30,740	$76,567	$(18,669)
Interest Rate Swaps			
Increase in interest expense (In thousands)	$(978)	$(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, 2010, our commodity 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, 2010, we had no deposits for collateral.

Capital Requirements

Our capital expenditures for the year ended December 31, 2010 were $339.4 million, including capitalized internal costs directly identified with acquisition, exploration and development activities of $7.8 million, capitalized interest of $4.0 million and corporate and other capital costs of $2.0 million. We have plans to execute an organic capital program in 2011 of $360.0 million that can be funded from internally generated cash flows, divestiture proceeds and available cash. We also have the discretion to use our available borrowing base to fund capital expenditures, including acquisitions.

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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, 2010, the aggregate amounts of our contractually obligated payment commitments for the next five years were as follows:

	Payments Due By Period				
	Total	2011	2012 to 2013	2014 to 2015	2016 & Beyond
			(In thousands)		
Senior secured revolving line of credit	$ 130,000	$ -	$ 130,000	$ -	$ -
Second lien term loan	20,000	-	20,000	-	-
Senior notes	200,000	-	-	-	200,000
Operating leases	10,784	3,400	6,716	668	-
Interest payments on long-term debt (1)	130,600	23,197	38,528	38,528	30,347
Field service agreements	23,437	23,437	-	-	-
Rig commitments	4,758	4,758	-	-	-
Total contractual obligations	$ 519,579	$ 54,792	$ 195,244	$ 39,196	$ 230,347

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2010.

Asset Retirement Obligations. We also had total liabilities of $27.9 million at December 31, 2010 related to asset retirement obligations that are excluded from the table above. Of the total ARO, the current portion was approximately $9.3 million at December 31, 2010 and was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO was approximately $18.6 million at December 31, 2010 and was included in Other long-term liabilities on the Consolidated Balance Sheet. 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 legal proceedings arising in 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. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, 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.

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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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 impacts 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 December 31, 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."

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. 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."

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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 $0.11 to $0.13 per Mcfe. This estimated impact is based on current data at December 31, 2010 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, 2010, our full cost pool had approximately $91.1 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.

Derivative Transactions and Hedging Activities

We enter into derivative transactions to hedge against changes in oil, natural gas and NGL prices 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 oil, natural gas and NGL production through 2012.

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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 2010. These transactions were recorded in our financial statements in accordance with authoritative guidance for accounting for derivative instruments and hedging activities. Although not risk free, we believed these agreements reduced our exposure to commodity price fluctuations and changes in interest rates and thereby enabled us to achieve a more predictable cash flow. We did 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 Company's financial assets and liabilities were 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. 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's (the "Index") 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 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 sales 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. In connection with the planned asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, we concluded that it is more likely than not that the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances have been established for these items as well as state NOLs in other jurisdictions in which we previously operated but have since divested of operating assets. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. 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 $0.5 million for the year ended December 31, 2010.

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.

Recent Accounting Developments

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

Financing Receivables. In July 2010, the FASB issued authoritative guidance related to improving disclosures around the credit quality of financing receivables and associated allowances for credit losses. This guidance requires a reporting entity to provide additional disclosures about the nature of the credit risk inherent in the entity's portfolio of financing receivables, how that risk is analyzed and the assessment in determining the allowance for credit losses, as well as discussion of the changes in the allowance for credit losses. The guidance will be required for interim and annual reporting periods effective January 1, 2011. As we have no financing receivables, this guidance will not impact our disclosures and will not impact our consolidated financial position, results of operations or cash flows.

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Fair Value Measurements. 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.

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 was effective on January 1, 2010 and did not have an impact on our consolidated financial position, results of operations or cash flows.

Off-Balance Sheet Arrangements

At December 31, 2010, we did not have any off-balance sheet arrangements.

Forward-Looking Statements

This report includes “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 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,” “p “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of 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:

– 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 where we conduct business;

– conditions in the energy and financial markets;

– 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;

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– 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 constraints;

– developments in oil-producing and natural gas-producing countries;

– drilling and exploration risks;

– legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, changes relating to national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, environmental regulations and 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.

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, natural gas and NGL 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 – Liquidity and Capital Resources - 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, natural gas and NGL production. Realized pricing is primarily driven by the prevailing price for crude oil and spot market prices applicable to our U.S. natural gas and NGL production. Pricing for oil, natural gas and NGL production has been volatile and unpredictable for several years and we expect this volatility to continue in the future. Accordingly, we use certain derivative instruments, including fixed price swaps, basis swaps, costless collars and put options. Although not risk free, we believe these activities will reduce commodity price fluctuations and thereby enable us to achieve a more predictable cash flow.

Our fixed price swap agreements are used to fix the sales price for our anticipated future natural gas and NGL 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 also have the ability to enter into fixed price swap agreements to fix the sales price for our anticipated future oil production. Should this type of arrangement become attractive, we may enter into these types of agreements in the future.

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Our costless collar agreements are used to fix the sales price within a floor price and ceiling 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 when required as defined in each instrument. When the floating market price exceeds the ceiling price, we pay our counterparty. When the floor price exceeds the floating market price, our counterparty is required to make payment to us. If the floating market price is within the floor and ceiling prices, no payments are required by either the Company or the counterparties. We have designated these costless collars as cash flow hedges. We also have the ability to enter into costless collar agreements to fix the sales price within a floor price and ceiling price for our anticipated future NGL production. Should this type of arrangement become attractive, we may enter into these types of agreements in the future.

As of December 31, 2010, we had open natural gas derivative hedges in an asset position with a fair value of $28.6 million. A 10% increase in natural gas prices would reduce the fair value by approximately $8.9 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $9.3 million. The effects of these derivative transactions on our natural gas sales are discussed above under Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Revenues – Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009 – Natural Gas.”

As of December 31, 2010, we had open crude oil derivative hedges in a liability position with a fair value of $4.9 million. A 10% increase in crude oil prices would reduce the fair value by approximately $10.8 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $8.6 million. The effects of these derivative transactions on our crude oil sales are discussed above under Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Revenues – Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009 – Crude Oil”.

As of December 31, 2010, we had open NGL derivative hedges in a liability position with a fair value of $4.0 million. A 10% increase in NGL prices would reduce the fair value by approximately $2.6 million, while a 10% decrease in NGL prices would increase the fair value by approximately $2.6 million. The effects of these derivative transactions on our NGL sales are discussed above under Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations – Revenues – Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009 – NGLs”.

These fair value changes assume volatility based on prevailing market parameters at December 31, 2010.

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 determined the impact to the fair value of our derivative assets at December 31, 2010 was insignificant. We currently do not know of any circumstances that would limit access to our credit facilities or require a change in our debt or hedging structure.

At December 31, 2010, we had the following financial fixed price swap and costless collar transactions outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	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	Fair Market Value Asset/(Liability) (In thousands)

Natural Gas	2011	Swap	Cash flow	15,000	5,475,000	$ 5.90	$ -	$ 8,472
Natural Gas	2011	Costless Collar	Cash flow	35,000	12,775,000	5.79	7.27	16,488
Natural Gas	2012	Costless Collar	Cash flow	10,000	3,660,000	5.75	7.15	3,613
					21,910,000			$ 28,573

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
Crude Oil	2011	Costless Collar	Cash flow	2,300	839,500	$ 73.26	$ 99.96	$ (3,066)
Crude Oil	2012	Costless Collar	Cash flow	2,100	768,600	75.00	104.61	(1,837)
					1,608,100			$ (4,903)

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Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
NGL - Propane	2011	Swap	Cash flow	350	127,750	$ 41.92	$ -	$ (1,237)
NGL - Isobutane	2011	Swap	Cash flow	110	40,150	$ 56.18	$ -	$ (490)
NGL - Normal Butane	2011	Swap	Cash flow	100	36,500	$ 54.81	$ -	$ (477)
NGL - Pentane Plus	2011	Swap	Cash flow	140	51,100	$ 70.61	$ -	$ (914)
NGL - Propane	2012	Swap	Cash flow	250	91,500	$ 42.84	$ -	$ (474)
NGL - Isobutane	2012	Swap	Cash flow	50	18,300	$ 61.95	$ -	$ (82)
NGL - Normal Butane	2012	Swap	Cash flow	50	18,300	$ 60.90	$ -	$ (78)
NGL - Pentane Plus	2012	Swap	Cash flow	100	36,600	$ 79.28	$ -	$ (261)
					420,200			$ (4,013)

Subsequent to December 31, 2010, we entered into additional hedging transactions to hedge portions of our expected future natural gas, crude oil and NGL production, excluding the ethane component of the NGL barrel. See Item 8. "Financial Statements and Supplementary Data, Note 18 – Subsequent Events."

Interest Rate Risk. Borrowings under our Restated Revolver mature on July 1, 2012 and bear interest at a LIBOR-based rate. To mitigate our exposure to rising interest rates, we entered into a series of interest rate swap agreements through December 2010. We may enter into additional interest rate swap agreements in the future to mitigate interest rate risk if the costs are not prohibitive.

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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

Houston, Texas
February 25, 2011

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Item 8. Financial Statements and Supplementary Data

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

	December 31, 2010	2009
Assets		
Current assets:		
Cash and cash equivalents	$41,634	$61,256
Accounts receivable	44,028	32,691
Derivative instruments	19,145	8,983
Prepaid expenses	2,711	2,837
Other current assets	5,454	6,415
Total current assets	112,972	112,182
Oil and natural gas properties, full cost method, of which $91,148 million at December 31, 2010 and $42,344 million at December 31, 2009 were excluded from amortization	2,262,161	2,011,972
Other fixed assets	14,459	12,417
	2,276,620	2,024,389
Accumulated depreciation, depletion, and amortization, including impairment	(1,546,631)	(1,433,787)
Total property and equipment, net	729,989	590,602
Deferred loan fees	7,652	4,921
Deferred tax asset	142,710	169,732
Derivative instruments	1,523	-
Other assets	2,463	2,147
Total other assets	154,348	176,800
Total assets	$997,309	$879,584
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$3,669	$2,279
Accrued liabilities	57,006	37,107
Royalties payable	14,542	16,064
Derivative instruments	-	236
Prepayment on gas sales	7,869	7,542
Deferred income taxes	7,132	3,258
Total current liabilities	90,218	66,486
Long-term liabilities:		
Derivative instruments	1,011	1,960
Long-term debt	350,000	288,742
Other long-term liabilities	27,264	29,301
Total liabilities	$468,493	$386,489
Commitments and contingencies (Note 11)		
Stockholders' equity:		
	-	-

Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2010 or 2009		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 52,031,004 shares and 51,254,709 shares at December 31, 2010 and 2009, respectively	52	51
Additional paid-in capital	793,293	780,196
Treasury stock, at cost; 343,093 and 199,955 shares at December 31, 2010 and 2009, respectively	(6,896)	(3,473)
Accumulated other comprehensive income	11,259	4,259
Accumulated deficit	(268,892)	(287,938)
Total stockholders' equity	528,816	493,095
Total liabilities and stockholders' equity	$997,309	$879,584

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,		
	2010	2009	2008
Revenues:			
Natural gas sales	$208,688	$250,684	$398,268
Oil sales	54,542	21,763	55,736
NGL sales	45,200	21,504	45,343
Total revenues	308,430	293,951	499,347
Operating costs and expenses:			
Lease operating expense	51,085	60,773	55,694
Depreciation, depletion, and amortization	116,558	121,042	198,862
Impairment of oil and gas properties	-	379,462	444,369
Treating, transportation and marketing	6,963	6,268	9,387
Production taxes	5,953	6,131	13,528
General and administrative costs	56,332	46,993	52,846
Total operating costs and expenses	236,891	620,669	774,686
Operating income (loss)	71,539	(326,718)	(275,339)
Other (income) expense:			
Interest expense, net of interest capitalized	27,073	19,258	14,688
Interest income	(38)	(97)	(1,600)
Other (income) expense, net	(1,087)	(876)	12,510
Total other expense	25,948	18,285	25,598
Income (loss) before provision for income taxes	45,591	(345,003)	(300,937)
Income tax expense (benefit)	26,545	(125,827)	(112,827)
Net income (loss)	$19,046	$(219,176)	$(188,110)
Earnings (loss) per share:			
Basic	$0.37	$(4.30)	$(3.71)
Diluted	$0.37	$(4.30)	$(3.71)
Weighted average shares outstanding:			
Basic	51,381	50,979	50,693
Diluted	52,168	50,979	50,693

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,		
	2010	2009	2008
Cash flows from operating activities			
Net income (loss)	$19,046	$(219,176)	$(188,110)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	116,558	121,042	198,862
Impairment of oil and gas properties	-	379,462	444,369
Deferred income taxes	26,740	(124,632)	(116,519)
Amortization of deferred loan fees recorded as interest expense	2,828	2,102	1,027
Amortization of original issue discount recorded as interest expense	1,258	342	-
Stock compensation expense	14,147	7,836	7,234
Unrealized (gain)/loss on derivative instruments	(1,715)	-	-
Other non-cash items	-	-	(512)
Change in operating assets and liabilities:			
Accounts receivable	(11,337)	9,194	13,163
Income taxes receivable	-	-	(776)
Prepaid expenses	852	2,209	5,367
Other current assets	961	(2,344)	178
Other assets	(316)	(484)	191
Accounts payable	1,390	11	5,031
Accrued liabilities	6,848	(1,897)	7,322
Royalties payable	(1,195)	(13,164)	(2,108)
Long-term liabilities	796	-	-
Net cash provided by operating activities	176,861	160,501	374,719
Cash flows from investing activities			
Acquisition of oil and gas properties	(5,874)	(3,844)	(163,187)
Purchases of oil and gas assets	(328,889)	(141,016)	(228,464)
Disposals of oil and gas properties and assets	83,142	19,574	-
(Increase) decrease in restricted cash	-	1,421	(1,421)
Other	-	-	2
Net cash used in investing activities	(251,621)	(123,865)	(393,070)
Cash flows from financing activities			
Borrowings on revolving credit facility	64,000	28,400	55,000
Payments on revolving credit facility	(124,000)	(40,000)	-
Issuance of Senior Notes	200,000	-	-
Repayment on Term Loan	(80,000)	-	-
Deferred loan fees	(6,282)	(5,855)	-
Proceeds from stock options exercised	4,843	21	3,617
Purchases of treasury stock	(3,423)	(801)	(627)
Net cash provided by (used in) financing activities	55,138	(18,235)	57,990
Net (decrease) increase in cash	(19,622)	18,401	39,639
Cash and cash equivalents, beginning of year	61,256	42,855	3,216
Cash and cash equivalents, end of year	$41,634	$61,256	$42,855

Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$22,987	$16,813	$13,658
Cash paid (received) for tax	$337	$(1,196)	$4,470
Supplemental non-cash disclosures:			
Capital expenditures included in accrued liabilities	$22,945	$18,199	$26,555
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 Capital	Treasury Stock		Accumulated Other Comprehensive (Loss)/Income	Retained Earnings / Accumulated Deficit	T Stoc E
	Shares	Amount		Shares	Amount			
Balance at December 31, 2007	50,542,648	$ 50	$ 762,827	109,303	$ (2,045)	$ (7,225)	$ 119,348	$
Stock options exercised	214,119	1	3,615	-	-	-	-	
Treasury stock - employee tax payment	-	-	-	46,487	(627)	-	-	
Stock-based compensation	-	-	7,234	-	-	-	-	
Vesting of restricted stock	274,714	-	-	-	-	-	-	
Comprehensive loss:	-	-	-	-	-	-	-	
Net loss	-	-	-	-	-	-	(188,110)	
Change in fair value of derivative hedging instruments	-	-	-	-	-	30,057	-	
Hedge settlements reclassified to income	-	-	-	-	-	19,829	-	
Tax expense related to cash flow hedges	-	-	-	-	-	(18,582)	-	
Comprehensive loss	-	-	-	-	-	-	-	
Balance at December 31, 2008	51,031,481	$ 51	$ 773,676	155,790	$ (2,672)	$ 24,079	$ (68,762)	$
Stock options exercised	14,125	-	21	-	-	-	-	
Treasury stock - employee tax payment	-	-	-	44,165	(801)	-	-	
	-	-	6,499	-	-	-	-	

Stock-based compensation													
Vesting of restricted stock	209,103		-		-	-		-		-		-	
Comprehensive loss:	-		-		-	-		-		-		-	
Net loss	-		-		-	-		-		-		(219,176)	
Change in fair value of derivative hedging instruments	-		-		-	-		-		43,693		-	
Hedge settlements reclassified to income	-		-		-	-		-		(75,278)		-	
Tax expense related to cash flow hedges	-		-		-	-		-		11,765		-	
Comprehensive loss	-		-		-	-		-		-		-	
Balance at December 31, 2009	51,254,709	$	51	$	780,196	199,955	$	(3,473)	$	4,259	$	(287,938)	$
Stock options exercised	287,397		1		4,842	-		-		-		-	
Treasury stock - employee tax payment	-		-		-	143,138		(3,423)		-		-	
Stock-based compensation	-		-		8,255	-		-		-		-	
Vesting of restricted stock	488,898		-		-	-		-		-		-	
Comprehensive loss:	-		-		-	-		-		-		-	
Net Income	-		-		-	-		-		-		19,046	
Change in fair value of derivative hedging instruments	-		-		-	-		-		42,632		-	
Hedge settlements reclassified to income	-		-		-	-		-		(31,477)		-	
Tax expense related to cash flow hedges	-		-		-	-		-		(4,155)		-	
Comprehensive income	-		-		-	-		-		-		-	
	52,031,004	$	52	$	793,293	343,093	$	(6,896)	$	11,259	$	(268,892)	$

Balance at
December 31,
2010

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

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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 engaged in onshore oil and natural gas exploration, development, production and acquisition activities in the United States. The Company's operations are concentrated in the core areas of South Texas, including the Eagle Ford shale, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in northwest Montana.

In preparing these financial statements, events occurring after December 31, 2010 were evaluated by the Company to ensure that any subsequent events that meet the criteria for recognition and/or disclosure in this report, have been included. See Note 18 – 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 SEC rules released in December 2008 "Modernization of Oil and Gas Reporting" which became effective December 31, 2009. The principal revisions under the authoritative guidance included changing the manner in which oil and gas reserves were estimated as well as the manner in which prices were 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 in 2009 was not significant to the Company's financial statements. The adoption of the rule will continue to result in future amounts recorded for depreciation, depletion and amortization and ceiling limitations being different from what would have been recorded if the rules would not have been mandated.

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 its estimates and assumptions on a regular basis. The Company bases its 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.

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 facilities, 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

As of December 31, 2010, the Company had no restricted cash.

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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 $7.8 million, $4.8 million and $7.1 million of internal costs for the years ended December 31, 2010, 2009 and 2008, 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 $2.32, $2.39 and $3.71 per Mcfe in 2010, 2009 and 2008, respectively.

Due to the volatility of commodity prices, should oil and natural gas prices decline in the future and 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 a write-down of our oil and gas properties could occur.

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. The Company develops estimates of these costs for each of its 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. The Company reviews its assumptions and estimates of future development and future abandonment costs on an annual basis.

The Company provides 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.

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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, 2010 is $350.0 million. The Company calculated the fair value of its long-term debt as of December 31, 2010 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 $363.6 million as of December 31, 2010. The fair market value of debt as of December 31, 2009 was $303.0 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 Company's Restated Revolver, Restated Term Loan and Senior Notes (each as hereafter defined in Note 10 – Long-Term Debt) 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, crude oil and NGLs. The Company also uses derivatives to manage interest rate risk associated with its debt under its Restated Revolver. The Company periodically enters into derivative contracts, including fixed price swaps or costless 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 the Company's expected proved production from existing wells at inception of the hedge instruments or debt under its current Restated Revolver.

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 Note 6 – Commodity Hedging Contracts and Other Derivatives for a description of the derivative contracts which the Company executes.

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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 as of December 31, 2010 or 2009.

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 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 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 the Company's stock 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 $6.7 million of related excess tax benefits which will be recognized upon utilization of the Company's 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, 2010 and 2009, there were no shares of preferred stock outstanding.

Treasury Stock

The Company repurchased shares that were surrendered by employees and directors 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 and the Company does not have a publicly announced program to repurchase shares of common stock.

Revenue Recognition

The Company uses the sales method of accounting for the sale of its natural gas. When actual natural gas sales volumes exceed the Company's delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. As of December 31, 2010 and 2009, these 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.

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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.

Financing Receivables. In July 2010, the FASB issued authoritative guidance related to improving disclosures around the credit quality of financing receivables and associated allowances for credit losses. This guidance requires a reporting entity to provide additional disclosures about the nature of the credit risk inherent in the entity's portfolio of financing receivables, how that risk is analyzed and the assessment in determining the allowance for credit losses, as well as discussion of the changes in the allowance for credit losses. This guidance will be required for interim and annual reporting periods effective January 1, 2011. As we have no financing receivables, this guidance will not impact our disclosures and will not impact our consolidated financial position, results of operations or cash flows.

Fair Value Measurements. 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 requires additional disclosures but will not impact the Company's consolidated financial position, results of operations or cash flows.

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 was effective on January 1, 2010 and does not have an impact on the Company's consolidated financial position, results of operations or cash flows.

(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31,	
	2010	2009
	(In thousands)	
Natural gas, NGLs and oil revenue sales	$ 41,851	$ 29,938
Joint interest billings	1,823	2,328
Short-term receivable for royalty recoupment	354	425
Total	$ 44,028	$ 32,691

There are no balances in accounts receivable that are considered to be uncollectible and an allowance was unnecessary as of December 31, 2010, 2009 and 2008.

(4) Property, Plant and Equipment

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

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	December 31, 2010	December 31, 2009
	(In thousands)	
Proved properties	$ 2,124,615	$ 1,931,054
Unproved/unevaluated properties	91,148	42,344
Gas gathering system and compressor stations	46,398	38,574
Other	14,459	12,417
Total	2,276,620	2,024,389
Less: Accumulated depreciation, depletion, and amortization	(1,546,631)	(1,433,787)
	$ 729,989	$ 590,602

Included in the Company's oil and natural gas properties are asset retirement costs of $18.7 million and $21.9 million as of December 31, 2010 and 2009, respectively, including additions of $0.2 million and $1.9 million for the year ended December 31, 2010 and 2009, respectively.

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

		2010			
	Total Impairment	December 31 (2)	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(3)		$4.38	$4.41	$4.10	$3.98
West Texas Intermediate oil price (per Bbl)(3)		75.96	73.85	72.25	66.13
Increase (decrease) of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		27,729	33,652	50,045	60,648
Impairment recorded (pre-tax) (in thousands)	$-	-	-	-	-
Potential impairment absent the effects of hedging (pre-tax) (in thousands) (4)		-	-	-	-

		2009			
	Total Impairment	December 31 (2)	September 30 (1)	June 30	March 31
Henry Hub natural gas price (per MMBtu)(3)		$3.87	$4.59	$3.89	$3.63
West Texas Intermediate oil price (per Bbl)(3)		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

		2008			
	Total Impairment	December 31	September 30	June 30	March 31

Henry Hub natural gas price (per MMBtu)(3)		$5.71	$7.12	$13.10	$9.37
West Texas Intermediate oil price (per Bbl)(3)		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	-	-

(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 December 31, 2010 and 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.

(3) Adjusted for basis and quality differentials.

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(4) Represents the total potential impairment excluding the effects of hedging. The Company would have no impairment recognized with or without the effects of hedging.

(5) Represents the total potential impairment excluding the effects of hedging. Where there is no potential impairment for the periods ended in 2009 and 2008, with the exception of the period ended December 31, 2009, the Company was able to utilize higher prices subsequent to period end and therefore no impairment was recognized with or without the effects of hedging.

The Company did not record any write-down or impairment for the year ended December 31, 2010 and a non-cash, pre-tax write-down of $379.5 million was recorded 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.

Capitalized costs excluded from DD&A as of December 31, 2010 and 2009, all of which are located onshore in the U.S., are as follows by the year in which such costs were incurred:

	December 31, 2010				
	Total	2010	2009	2008	Prior
	(In thousands)				
Development cost	$ 10,314	$ 10,314	$ -	$ -	$ -
Exploration cost	18,861	18,861	-	-	-
Acquisition cost of undeveloped acreage	58,161	35,432	8,978	13,751	-
Capitalized interest	3,812	1,779	776	1,257	-
Total capitalized costs excluded from DD&A	$ 91,148	$ 66,386	$ 9,754	$ 15,008	$ -

	December 31, 2009				
	Total	2009	2008	2007	Prior
	(In thousands)				
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
Total capitalized costs excluded from DD&A	$ 42,344	$ 23,485	$ 16,081	$ 2,747	$ 31

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $62.0 million and development and exploration costs of $29.2 million will be included in oil and gas properties subject to amortization within five years and one year, respectively.

Property Acquisitions. 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. In connection with the San Juan divestiture on December 3, 2010 as discussed below, the Company sold the working interest in this acreage.

During the fourth quarter of 2008 and the first quarter of 2009, the Company acquired a 100% working interest in a 1,280 acre position in the Pinedale Anticline in the Rockies for $38.8 million. As discussed below, the Company subsequently divested the Pinedale assets on December 3, 2010. Also in the fourth quarter of 2008, the Company acquired 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 first quarter of 2010, the Company purchased a non-producing leasehold in the South Texas Gates Ranch area for $11.3 million with an effective date of March 1, 2010. The Company further increased its working interest from 70% to 100% in certain properties in the South Texas Gates Ranch area for $12.5 million. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments.

During the second quarter of 2010, the Company purchased the remaining 30% working interest and obtained operatorship in the Catarina Field for $5.9 million from St. Mary Land & Exploration Company. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments. The Company then divested its Gulf Coast Texas State Waters Sabine Lake asset, a non-core property, for $10.2 million. The proceeds were recorded as an adjustment to the full cost pool with no gain or loss recognized. Also during the second quarter of 2010, the Company purchased an additional 315 acres and 5,000 acres in the Eagle Ford and Bakken plays, respectively, for approximately $946,000 and $200,000, respectively.

During the third quarter of 2010, the Company leased an additional 3,000 acres for $8.9 million in the Eagle Ford shale thereby increasing the Company’s acreage within the shale to approximately 65,000 acres. The Company also entered into a purchase and sale agreement to divest certain non-core properties located in Arkansas, Oklahoma, Mississippi, Texas and Louisiana for $37.1 million. The divestiture of these assets, collectively known as the Arklatex assets, closed on October 19, 2010 with an effective date of August 1, 2010 and was subject to post-closing purchase price adjustments.

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During the fourth quarter of 2010, the Company entered into a purchase and sale agreement to divest the Pinedale and San Juan assets located in Wyoming and New Mexico for $39.4 million. The divestiture closed on December 3, 2010 with an effective date of August 1, 2010 and was subject to post-closing purchase price adjustments.

Gas Gathering System and Compressor Stations. The gross book value of the Company's gas gathering system and compressor stations was $46.4 million and $38.6 million at December 31, 2010 and 2009, respectively, 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, 2010 and 2009 was $9.5 million and $7.7 million, respectively. The depreciation expense associated with the gas gathering system and compressor stations for the years ended December 31, 2010, 2009, and 2008 was $3.2 million, $2.5 million, and $2.2 million, respectively.

Other Property and Equipment. Other property and equipment at December 31, 2010 and 2009 of $14.5 million and $12.4 million, respectively, consisted primarily of furniture and fixtures. The accumulated depreciation associated with other assets at December 31, 2010 and 2009 was $6.4 million and $4.3 million, respectively. For the years ended December 31, 2010, 2009 and 2008 depreciation expense for other property and equipment was $2.1 million, $1.7 million and $1.2 million, respectively.

(5) Deferred Loan Fees

As of December 31, 2010 and 2009, deferred loan fees were $7.7 million and $4.9 million, respectively. Total amortization expense for deferred loan fees was $2.8 million, $2.1 million and $1.0 million for the years ended December 31, 2010, 2009 and 2008, 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 as of December 31, 2010:

Product	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	Fair Market Value Asset/(Liability) (In thousands)
Natural Gas	2011	Swap	Cash flow	15,000	5,475,000	$ 5.90	$ -	$ 8,472
Natural Gas	2011	Costless Collar	Cash flow	35,000	12,775,000	5.79	7.27	16,488
Natural Gas	2012	Costless Collar	Cash flow	10,000	3,660,000	5.75	7.15	3,613
					21,910,000			$ 28,573

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
Crude Oil	2011	Costless Collar	Cash flow	2,300	839,500	$ 73.26	$99.96	$ (3,066)
Crude Oil	2012	Costless Collar	Cash flow	2,100	768,600	75.00	104.61	(1,837)

	1,608,100	$ (4,903)

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Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
NGL - Propane	2011	Swap	Cash flow	350	127,750	$ 41.92	$ -	$ (1,237)
NGL - Isobutane	2011	Swap	Cash flow	110	40,150	$ 56.18	$ -	$ (490)
NGL - Normal Butane	2011	Swap	Cash flow	100	36,500	$ 54.81	$ -	$ (477)
NGL - Pentane Plus	2011	Swap	Cash flow	140	51,100	$ 70.61	$ -	$ (914)
NGL - Propane	2012	Swap	Cash flow	250	91,500	$ 42.84	$ -	$ (474)
NGL - Isobutane	2012	Swap	Cash flow	50	18,300	$ 61.95	$ -	$ (82)
NGL - Normal Butane	2012	Swap	Cash flow	50	18,300	$ 60.90	$ -	$ (78)
NGL - Pentane Plus	2012	Swap	Cash flow	100	36,600	$ 79.28	$ -	$ (261)
					420,200			$ (4,013)

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, 2010, the Company had no deposits for collateral.

The following table sets forth the results of derivative settlements for the respective period included in the Consolidated Statement of Operations:

	For the Year Ended December 31, 2010	2009	2008
Natural Gas			
Quantity settled (MMBtu)	14,645,000	20,856,465	26,684,616
Increase (decrease) in natural gas sales revenue (In thousands)	$ 30,740	$ 76,567	$ (18,669)
Interest Rate Swaps			
Increase in interest expense (In thousands)	$ (978)	$ (1,289)	$ (1,158)

For the year ended December 31, 2010, the Company recognized $1.7 million in unrealized derivative gains in earnings and expects to reclassify net gains of $17.4 million from Accumulated other comprehensive income on the Consolidated Balance Sheet to earnings based upon settlement dates in the next twelve months and based upon current forward prices as of December 31, 2010.

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, oil and NGL 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, oil, and NGL 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, 2010, the Company had outstanding natural gas, oil and NGL commodity forward contracts with notional volumes of 21,910,000 MMBtus, 1,608,100 Bbls and 420,200 Bbls, respectively, that were entered into to hedge forecasted natural gas, oil and NGL sales.

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, 2010 is as follows:

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Fair Values of Derivative Instruments

Derivative Assets (Liabilities)

(In thousands)

Derivatives designated as hedging instruments	Balance Sheet Location	Fair Value December 31, 2010	Fair Value December 31, 2009
Interest rate swap	Derivative Instruments - current assets	$-	$(399)
Interest rate swap	Derivative Instruments - current liabilities	-	(236)
Commodity contracts - natural gas	Derivative Instruments - current assets	24,959	9,382
Commodity contracts - natural gas	Derivative Instruments - non-current assets	3,614	(1,960)
Commodity contracts - crude oil	Derivative Instruments - current assets	(2,696)	-
Commodity contracts - crude oil	Derivative Instruments - non-current assets	(2,207)	-
Commodity contracts - NGL	Derivative Instruments - current assets	(3,118)	-
Commodity contracts - NGL	Derivative Instruments - non-current assets	116	-
Commodity contracts - NGL	Derivative Instruments - long-term liability	(1,011)	-
Total derivatives designated as hedging instruments		$19,657	$6,787
Total derivatives not designated as hedging instruments		$-	$-
Total derivatives		$19,657	$6,787

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

	December 31, 2010 (In thousands)		OCI into Income (Effective Portion)	December 31, 2010 (In thousands)		Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	December 31, 2010 (In thousands)
Interest rate swap	$ (344	)	Interest expense, net of interest capitalized	$ (978	)	Interest expense, net of interest capitalized	$ -
Commodity contracts - natural gas	51,892		Natural gas sales	30,740		Natural gas sales	1,715
Commodity contracts - crude oil	(4,903	)	Crude oil sales	-		Crude oil sales	-
Commodity contracts - NGL	(4,013	)	NGL sales	-		NGL sales	-
Total	$ 42,632		Total	$ 29,762		Total	$ 1,715

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Twelve Months Ended December 31, 2009 (In thousands)		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 Ended December 31, 2009 (In thousands)		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) (2) Twelve Months 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 - natural gas	45,616		Natural gas sales	76,567		Natural gas sales	-	

Total	$ 43,693	Total	$ 75,800	Total	$ (522)

(1) This amount represents the unrealized gain which resulted from the termination of hedge accounting for a derivative being used to hedge anticipated production from our Pinedale properties.

(2) The loss of $0.5 million for the year ended December 31, 2009 is related to the ineffective portion of the hedging relationship. Nothing was excluded from the assessment of hedge effectiveness.

(7) Fair Value Measurements

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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 were impaired during the period-ended December 31, 2010, and no other fair value measurements are required to be recognized on a non-recurring basis, no additional disclosures are provided at December 31, 2010.

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 and NGL fixed price swaps, natural gas and crude oil 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, 2010 and 2009. 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, as one of its inputs, 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, 2010 and 2009. 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, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (liabilities):				
Money market funds	$ -	$ -	$ 1,035	$ 1,035

Commodity derivative contracts	-	-	19,657	19,657
Interest rate swap contracts	-	-	-	-
Total	$ -	$ -	$ 20,692	$ 20,692

	Fair value as of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
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

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 concluded the impact to the fair value of our derivative assets at December 31, 2010 was insignificant.

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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, 2010 and 2009. 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, 2010 and 2009.

	For the year ended December 31, 2010		
	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2010	$6,787	$2,035	$8,822
Total (gains) losses (realized or unrealized)			
included in earnings	-	-	-
included in other comprehensive income	42,632	-	42,632
Purchases, issuances and settlements	(29,762)	(1,000)	(30,762)
Transfers in and out of level 3	-	-	-
Balance at December 31, 2010	$19,657	$1,035	$20,692
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, 2010	$-	$-	$-

	For the year ended December 31, 2009		
	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
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	$-	$-	$-

(8) Accrued Liabilities

The Company's accrued liabilities consist of the following:

	December 31,	
	2010	2009
	(In thousands)	
Accrued capital costs	$ 22,945	$ 18,200
Accrued payroll and employee incentive expense	11,029	7,137
Accrued lease operating expense	7,059	8,011
Accrued interest	4,270	-
Asset retirement obligation	9,261	956
Other	2,442	2,803
Total	$ 57,006	$ 37,107

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(9) Asset Retirement Obligations

The following table provides a roll forward of the asset retirement obligations. Liabilities incurred during the period include additions to obligations as well as obligations that were assumed by the Company related to acquired properties. Liabilities settled during the period include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Activity related to the Company's asset retirement obligation ("ARO") is as follows:

	For the Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
ARO at the beginning of the period	$ 28,920	$ 27,944	$ 22,670
Revision of previous estimate	322	(1,886)	1,785
Liabilities incurred during period	629	1,855	1,727
Liabilities settled during period	(4,130)	(1,328)	(363)
Accretion expense	2,193	2,335	2,125
ARO at the end of the period	$ 27,934	$ 28,920	$ 27,944

Of the total ARO, the current portion was approximately $9.3 million and $1.0 million at December 31, 2010 and 2009, respectively, and was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO was approximately $18.6 million and $27.9 million at December 31, 2010 and 2009, respectively, and was included in Other long-term liabilities on the Consolidated Balance Sheet.

(10) Long-Term Debt

Long-term debt consists of the following:

	December 31,	
	2010	2009
	(In thousands)	
Amended and Restated Senior Revolving Credit Facility	$ 130,000	$ 190,000
Amended and Restated Second Lien Term Loan	20,000	100,000
Senior Notes	200,000	-
	350,000	290,000
Less:		
Original issue discount on amended and restated second lien term loan	-	(1,258)
Current portion of long-term debt	-	-
	$ 350,000	$ 288,742

Senior Secured Revolving Credit Facility. The Company's amended and restated revolving credit agreement (the "Restated Revolver") provides for a senior secured revolving line of credit of up to $600.0 million and matures on 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 as well as asset divestitures. The borrowing base is dependent on a number of factors, including the Company's 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.

The Company's borrowing base was confirmed by its lenders in October 2010 at $365.0 million. In accordance with the agreement, the borrowing base was adjusted in December 2010 to $325.0 million after the successful divestitures of the Pinedale and San Juan assets. As of December 31, 2010, the Company had $195.0 million of available borrowing capacity under its Restated Revolver. 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 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 the Company’s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, 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, 2010, the Company’s current ratio was 3.5 and the leverage ratio was 1.7. In addition, the Company is subject to covenants 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, 2010. As of February 18, 2011, the Company had $130.0 million outstanding, with $195.0 million available for borrowing under the Restated Revolver. The borrowing base will be subject to further adjustment pending the potential DJ Basin and Sacramento Basin divestitures.

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Second Lien Term Loan. The Company's amended and restated term loan (the "Restated Term Loan") matures on October 2, 2012. On April 15, 2010, the Company repaid $80.0 million of variable rate borrowings outstanding under the Restated Term Loan, which bore interest at LIBOR plus 8.5% with a LIBOR floor of 3.5%. In connection with the repayment, the Company paid an early termination premium of $1.3 million. 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 were clearly and closely related to the debt instrument, it did not represent an embedded derivative to be accounted for separately. As of December 31, 2010, the Company had $20.0 million of fixed rate borrowings outstanding bearing interest at 13.75% under the Restated Term Loan. The loan is collateralized by second priority liens on substantially all of the Company's assets. The Company is subject to the financial covenants as defined in the term loan agreement. The Company is required under the term loan agreement to maintain a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require the Company to maintain a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. At December 31, 2010, the Company's reserve coverage ratio was 2.2 and the leverage ratio was 1.7. In addition, the Company is subject to covenants, including limitations on 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, 2010. The Company also has the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the "Senior Notes") in a private offering. The Senior Notes were issued under an indenture (the "Indenture") with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit the Company's ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company's restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under the Restated Revolver and $80.0 million of variable rate borrowings outstanding under our Restated Term Loan and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

As of December 31, 2010, the Company had total outstanding borrowings of $350.0 million and for the year ended December 31, 2010, the Company's weighted average borrowing rate was 7.06%. Other than $150.0 million of debt that becomes due in 2012, the Company does not have any debt that matures in the five years ending December 31, 2015.

(11) Commitments and Contingencies

The Company is party to various legal proceedings arising in 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. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, 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 $5.0 million, $4.3 million and $3.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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Future minimum annual rental commitments under non-cancelable leases at December 31, 2010 were as follows:

		(In thousands)
2011		3,400
2012		3,349
2013		3,367
2014		668
2015		-
Thereafter		-
	$	10,784

The Company also has drilling rig commitments and field service agreements of approximately $4.8 million and $23.4 million, respectively, for 2011.

(12) Stock-Based Compensation

Stock-based compensation expense recorded for all share-based payment arrangements for the years ended December 31, 2010, 2009 and 2008 was $14.1 million, $7.5 million and $7.2 million, respectively, with an associated tax benefit of $5.0 million, $2.7 million and $2.9 million, respectively. For the years ended December 31, 2010 and 2009, the Company capitalized $0.6 million and $0.4 million, respectively, of stock-based compensation expense. No amounts of stock-based compensation expense were capitalized for the year ended December 31, 2008. The remaining unrecognized compensation expense associated with total unvested awards as of December 31, 2010 was approximately $5.5 million.

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 plan was recently amended to provide for the immediate vesting of awards in the event of the death or disability of a participant. 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 the Company and (ii) 200,000 shares during each fiscal year thereafter.

Stock Options

The Company has granted stock options under the Plan, which 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.

During the year ended December 31, 2010, no options were granted to employees. The weighted average fair value at date of grant for options granted during the years ended December 31, 2009 and 2008 was $3.42 per share and $9.19 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,		
	2010 (1)	2009	2008
Expected option term (years)	-	6.5	6.5
Expected volatility	-	42.45% - 56.95 %	42.45 %
Expected dividend rate	-	0.00 %	0.00 %
Risk free interest rate	-	2.42% - 3.19 %	3.48% - 3.84 %

(1) No options were granted to employees during the year ended December 31, 2010.

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.

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The following table summarizes information related to outstanding and exercisable options held by the Company's employees and directors at December 31, 2010:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
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		
Granted	-	-		
Exercised	(287,397)	16.13		
Forfeited	(149,318)	14.69		
Outstanding at December 31, 2010	811,254	$ 14.36		
Options vested and exercisable at December 31, 2010	523,502	$ 16.88	5.76	$ 11,023

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2010, 2009 and 2008 was $0.6 million, $1.1 million and $1.7 million, respectively. Unrecognized expense as of December 31, 2010 for all outstanding stock options was $0.4 million and will be recognized over a weighted average period of 0.9 years.

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009 and 2008 was $4.1 million, $0.1 million and $1.4 million, respectively.

Restricted Stock

The Company has granted restricted stock under the 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 10% 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, 2010:

	Shares	Weighted Average Grant Date Fair Value
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
Granted	299,811		20.91
Vested	(488,898)		13.66
Forfeited	(172,560)		14.15
Non-vested shares outstanding at December 31, 2010	763,011	$	14.76

The non-vested restricted stock outstanding at December 31, 2010 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, 2010 was $11.4 million.

Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2010, 2009 and 2008 was $6.1 million, $5.1 million and $5.5 million, respectively. Unrecognized expense as of December 31, 2010 for all outstanding restricted stock awards was $5.1 million and will be recognized over a weighted average period of 1.22 years.

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Performance Share Units

Pursuant to the approved Plans, the Company's Compensation Committee agreed to allocate a portion of the 2009 and 2010 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 the 2009 PSU awards in cash and 2010 PSU awards in common stock. Consequently, the 2009 PSU awards are accounted for as liability-classified awards and are included as a component of Other long-term liabilities. The 2010 PSU awards are accounted for as equity-classified awards and are included as a component of Additional paid-in capital. At the end of the three-year performance periods, the number of shares vested can range from 0% to 200% of the targeted amounts as determined by the Compensation Committee of the Board of Directors. None of these PSUs have voting rights and they 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, 2010, one-third of the 2009 and 2010 PSUs granted to executive employees included 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 S&P 400 O&G E&P Industry Index (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 these types of awards. Expenses related to these awards can be volatile based on the Company's comparative performance at the end of each quarter.

The following assumptions were used as of December 31, 2010 for the Monte Carlo model to value the expense and liability components of the awards that contain market conditions:

	December 31, 2010	
	2009 PSU Plan	2010 PSU Plan

Expected term of award (years)	3	3
Risk-free interest rate	0.43 %	0.79 %
Rosetta volatility	54.91 %	56.29 %
Index volatility	34.46 %	35.76 %
Rosetta/Index correlation	80 %	80 %

The following table summarizes information related to PSUs held by the Company's officers at December 31, 2010:

	2009 PSU Plan	2010 PSU Plan
Unvested PSUs at December 31, 2009	345,530	-
Granted	-	169,370
Vested	-	-
Forfeited	(24,671)	(16,118)
Unvested PSUs at December 31, 2010	320,859	153,252

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The fair value per unit at December 31, 2010 was $37.64 for both the 2009 and 2010 PSU awards with performance conditions and $37.61 and $15.61 for the 2009 and 2010 PSU awards, respectively, with market conditions. For the year ended December 31, 2010, the Company recognized $6.5 million and $0.9 million of compensation expense associated with the 2009 and 2010 PSU plans, respectively. As of December 31, 2010, the Company has recorded a long-term liability of $7.8 million associated with the 2009 plan and a $0.9 million adjustment to Additional paid-in capital associated with the 2010 plan.

At the current fair value and assuming that the Board elects 100% payout for the PSUs for all metrics, total compensation expense related to the PSUs to be recognized ratably over the 3-year service periods would be $12.1 million and $4.6 million for the 2009 and 2010 PSU plans, respectively, at December 31, 2010. 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,		
	2010	2009	2008
		(In thousands)	
Current:			
Federal	$ (535)	$ (1,611)	$ 2,304
State	340	416	1,388
	(195)	(1,195)	3,692
Deferred:			
Federal	17,739	(119,111)	(107,568)
State	9,001	(5,521)	(8,951)
	26,740	(124,632)	(116,519)
Total income tax expense (benefit) (1)	$ 26,545	$ (125,827)	$ (112,827)

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

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,					
	2010		2009		2008	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US Statutory Rate	$15,957	35.0 %	$(120,751)	35.0 %	$(105,327)	35.0 %
Income/franchise tax, net of federal benefit	2,682	5.9 %	(5,545)	1.6 %	(7,562)	2.5 %
Valuation Allowance	6,558	14.4 %	-	-	-	-
Non-deductible permanent items	1,477	3.2 %	181	0.0 %	-	-
Other, net	(129)	(0.3)%	288	(0.1)%	62	0.0 %
Total tax expense (benefit)	$26,545	58.2 %	$(125,827)	36.5 %	$(112,827)	37.5 %

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, the non-deductibility of certain incentive compensation and a valuation allowance against certain state deferred tax assets. 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.

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The components of deferred taxes are as follows:

	December 31, 2010	December 31, 2009
	(In thousands)	
Deferred tax assets		
Oil and gas properties basis differences	$ 72,243	$ 130,562
Alternative Minimum Tax credit	-	693
Accrued liabilities not currently deductible	7,913	6,501
Hedge activity	(162)	730
Net operating loss carryforward	69,179	31,429
Valuation Allowance	(6,558)	-
Other	95	(183)
Total deferred tax assets	142,710	169,732
Derivative Financial Instruments	(7,132)	(3,258)
Total gross deferred tax liabilities	(7,132)	(3,258)
Net deferred tax assets	$ 135,578	$ 166,474

The Company had a deferred tax asset related to federal and state net operating loss carryforwards of approximately $69.2 million and $31.4 million at December 31, 2010 and 2009, 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 property basis of $72.2 million and $130.6 million at December 31, 2010 and 2009, 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.

In connection with the planned asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded that it is more likely than not the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances have been established for these items as well as state NOLs in other jurisdictions in which the Company previously operated but has since divested of the operating assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

The roll forward of our deferred tax asset valuation allowance is as follows:

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Balance at the beginning of the year	$ -	$ -	$ -
Charged to provision for income taxes	6,558	-	-
Balance at the end of the year	$ 6,558	$ -	$ -

As of December 31, 2010, 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 U.S. 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.

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

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	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Basic weighted average number of shares outstanding	51,381	50,979	50,693
Dilution effect of stock option and awards at the end of the period (1)	787	-	-
Diluted weighted average number of shares outstanding	52,168	50,979	50,693
Anti-dilutive stock options and awards	26	1,364	592

(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.

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 information below is based on the physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

	Year Ended December 31,		
	2010 (1)	2009 (1)	2008 (1)
Natural Gas, Oil and NGL Revenues		(In thousands)	
Eagle Ford	$94,913	$2,730	$298
South Texas	74,569	94,315	216,270
California	65,532	65,295	141,569
Rockies	27,597	21,999	29,491
Gulf Coast	6,755	22,310	97,356
Other Onshore	6,609	10,735	33,032
Total	$275,975	$217,384	$518,016

(1) Excludes the effects of hedging gains of $32.5 million for the year ended December 31, 2010, hedging gains of $76.6 million for the year ended December 31, 2009 and hedging losses of $18.7 million for the year ended December 31, 2008.

Major Customers

For the year ended December 31, 2010, the Company had two major customers, Calpine Energy Services ("CES") and Shell Trading (US) Company ("Shell").

The Company's annual consolidated revenue from CES accounted for approximately 48%, 57% and 61% for the years ended December 31, 2010, 2009 and 2008, respectively, and is reflected in Oil sales and Natural gas sales. For the years ended December 31, 2010, 2009 and 2008, revenues from sales to CES were $121.2 million, $117.8 million, and $305.9 million, respectively. There was no receivable from CES at December 31, 2010 or 2009. 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, 2010 and 2009, the Company had $7.9 million and $7.5 million in the margin account for December sales to CES which is included in Prepayment on gas sales on the Consolidated Balance Sheet.

For the year ended December 31, 2010, the Company's annual consolidated revenue from Shell accounted for approximately 16% of our revenue and for each of the years ended December 31, 2009 and 2008, annual consolidated revenues from Shell were less than 10%. Revenues from sales to Shell are reflected in Oil sales. The increase in sales to Shell is attributable to increased purchases of Eagle Ford production. For the years ended December 31, 2010, 2009 and 2008, revenues from sales to Shell were $38.9 million, $15.2 million and $11.9 million, respectively. The receivable from Shell at December 31, 2010 was approximately $9.8 million.

(16) Restructuring and Reorganization Costs

In the third and fourth quarters of 2010, the Company announced an office closure affecting the Denver office and the restructuring and reorganization of Houston personnel as a result of strategic asset divestitures. All affected positions are located in the United States. Of the total 44 employees covered under the programs, 33 employees were terminated during 2010 and the programs are expected to be completed by the end of 2011.

A before-tax charge of $3.5 million ($2.3 million after-tax) was recorded in the fourth quarter of 2010 as General and administrative costs on the Consolidated Statement of Operations. The associated accrued liability was classified as current on the Consolidated Balance Sheet. Of the expenses incurred, approximately $2.3 million related to severance costs, $1.1 million related to the cease-use of the Denver office space and approximately $0.1 million related to relocation costs. While all future costs associated with the restructuring and reorganization cannot be fully anticipated, the total amount estimated that will be incurred is approximately $5.0 million.

During the third and fourth quarters of 2010, the Company made payments of approximately $243 thousand associated with these liabilities.

	Amounts before tax (In thousands)	
Balance at January 1, 2010	$	-
Accruals		3,467
Adjustments		-
Payments		(243)
Balance at December 31, 2010	$	3,224

(17) Guarantor Subsidiaries

The Company's Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several, and the subsidiaries of the Company, other than the subsidiary guarantors, are minor. In addition, there are no restrictions on the ability of the Company to obtain funds from its subsidiaries by dividend or loan. Finally, none of the Company's subsidiaries has restricted assets that exceed 25% of net assets as of the most recent fiscal year which may not be transferred to the Company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

(18) Subsequent Events

On January 20, 2011, the Company entered into an additional costless collar transaction to hedge 10,000 MMbtu/d of its expected natural gas production for January 2012 through December 2012. The costless collar has a floor price of $4.50 per MMbtu and a ceiling price of $5.46 per MMbtu.

On January 20 and February 7, 2011, the Company entered into additional costless collar transactions to hedge 1,100 Bbl/d of its expected crude oil production for March 2011 through December 2011 and 1,300 Bbl/d of its expected crude oil production for January 2012 through December 2012. The 2011 costless collars have an average floor price of $80.45 per Bbl and an average ceiling price of $110.24 per Bbl through December 2011 and the 2012 costless collars have an average floor price of $77.31 per Bbl and an average ceiling price of $113.48 per Bbl through December 2012. In addition, on February 7, 2011, the Company entered into a costless collar to hedge 2,600 Bbl/d of its expected crude oil production for January 2013 through December 2013 with a floor price of $75.00 per Bbl and a ceiling price of $124.65 per Bbl through December 2013.

Finally, on January 20, January 21, and February 8, 2011, the Company entered into eleven additional NGL fixed price swaps to hedge 1,300 Bbl/d of its expected NGL production for April 2011 through December 2011 at an average price of $64.09 per Bbl, excluding the ethane component of the NGL barrel, and eleven additional NGL fixed price swaps to hedge 1,500 Bbl/d of its expected NGL production for January 2012 through December 2012 at an average price of $62.36 per Bbl, excluding the ethane component of the NGL barrel.

As part of the strategic decision to focus on the development of the Eagle Ford shale, the Company executed a purchase and sale agreement for $55.0 million on February 22, 2011 for the divestiture of its DJ Basin assets in Colorado. This agreement is subject to due diligence and other termination rights and will be subject to post-closing adjustments. The Company expects this transaction to close in the second quarter of 2011.

On February 24, 2011, two wholly owned subsidiaries of Rosetta Resources Inc. (the “Company”), Rosetta Operating LP and Rosetta Resources Gathering LP, entered into an agreement to sell their California oil and gas assets to Vintage Petroleum, LLC, for $200,000,000 cash consideration, subject to customary closing conditions and purchase price adjustments. The Company expects that the transaction will close in the second quarter of 2011.

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.

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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, 2010 are based on estimates made by the Company's engineers and audited by the Company's independent engineers, Netherland, Sewell & Associates, Inc. ("NSAI"). The Company's primary reserves estimator is the Company's Corporate Engineering Manager who has 33 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is also a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Company makes representations to the independent engineers that it has provided all relevant operating data and documents, and in turn, the Company reviews 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 engineer and geologist charged with the Company's audit are both licensed professionals with more than 50 years of experience combined.

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, 2010 and 2009 was used for future sales of natural gas, crude oil and NGLs. As of December 31, 2008, 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.

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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, 2010, 2009 and 2008:

	2010	2009	2008
		(In thousands)	
Proved properties	$ 2,124,615	$ 1,931,054	$ 1,813,527
Unproved properties	91,148	42,344	50,252
Total	2,215,763	1,973,398	1,863,779
Less: Accumulated depletion	(1,530,799)	(1,421,743)	(927,961)
Net capitalized costs	$ 684,964	$ 551,655	$ 935,818

Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include asset retirement costs of $18.7 million, $21.9 million and $23.2 million as of December 31, 2010, 2009 and 2008, 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, 2010, 2009 and 2008:

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Acquisition costs of properties			
Proved	$ 28,445	$ 11,490	$ 103,177
Unproved	26,658	28,246	32,276
Subtotal	55,103	39,736	135,453
Exploration costs	49,108	24,550	35,735
Development costs	233,184	65,183	152,260
Total	$ 337,395	$ 129,469	$ 323,448

Results of Operations for Oil and Natural Gas Producing Activities

	Year Ended December 31,		
	2010 (1)	2009 (1)	2008 (1)
		(In thousands)	
Natural gas, oil and NGL producing revenues	$ 275,975	$ 217,384	$ 518,016
Production costs	64,001	73,172	78,609
Depreciation, depletion, and amortization	116,558	121,042	198,862
Impairment of oil and gas properties	-	379,462	444,369
Income (loss) before income taxes	95,416	(356,292)	(203,824)
Income tax provision (benefit)	55,555	(130,047)	(76,434)
Results of operations	$ 39,861	$ (226,245)	$ (127,390)

(1) Excludes the effects of hedging gains of $32.5 million for the year ended December 31, 2010, hedging gains of $76.6 million for the year ended December 31, 2009 and hedging losses of $18.7 million for the year ended

December 31, 2008.

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, 2010, 2009 and 2008, as estimated by the Company's reservoir engineers and audited by independent petroleum consultants in 2010 and 2009 and as estimated by independent petroleum consultants for 2008 and the changes in the net proved reserves for each of the three years then ended. There was no restatement of 2008 reserves as a result of the SEC's new reserve reporting guidance.

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	Natural gas (Bcf)(1)	Natural gas liquids and crude oil (MBbl)(2)(3)	Bcfe (1) equivalents (4)
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
Revisions of previous estimates (9)	(54)	868	(49)
Purchases in place	9	1,448	17
Extensions, discoveries and other additions	132	23,460	273
Sales in place	(56)	(1,237)	(63)
Production	(39)	(1,858)	(50)
Net proved reserves at December 31, 2010	289	31,727	479

Net proved developed reserves

	Proved Developed Reserves		
	Natural gas (Bcf) (1)	Natural gas liquids and crude oil (MBbl) (2) (3)	Bcfe (1) equivalents (4)
December 31, 2008 (8)	308	3,253	327
December 31, 2009	237	4,669	265
December 31, 2010	184	10,158	245

(1) Billion cubic feet or billion cubic feet equivalent, as applicable

(2) Thousand barrels

(3) Includes crude oil, condensate and natural gas liquids

(4) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

(5) Excludes estimated reserves pertaining to interests in certain leases and wells associated with the original purchase of properties from Calpine.

(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 proved developed reserves as a result of the new reserve reporting guidance.
(9) Upward revision of 11 Bcfe due to twelve-month first day of the month historical average commodity prices. Downward revision of 60 Bcfe primarily due to reducing Proved Undeveloped Reserves (PUDs) of 22 Bcfe in the South Texas Lobo trend and 36 Bcfe in the Sacramento Basin as these reserves are not scheduled to be developed within five years.

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 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 2010 and 2009 and costs as of the date of the estimate and, in 2008 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.

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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.

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, 2010, 2009 and 2008:

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	Year Ended December 31, 2010		
	Proved Developed	Proved Undeveloped	Total
	(In millions)		
Future cash inflows	$1,351	$ 1,638	$2,989
Future production costs	(471)	(235)	(706)
Future development costs	(23)	(493)	(516)
Future income taxes	(165)	(175)	(340)
Future net cash flows	692	735	1,427
Discount to present value at 10% annual rate	(453)	(277)	(730)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$239	$ 458	$697

	Year Ended December 31, 2009		
	Proved Developed	Proved Undeveloped	Total
	(In millions)		
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	Total
	(In millions)		
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

(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 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.

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, 2010, 2009 and 2008:

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	(In millions)
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
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(212)
Net changes in prices and production costs	126
Extensions, discoveries, additions and improved recovery, net of related costs	495
Development costs incurred	128
Revisions of previous quantity estimates and development costs	(95)
Accretion of discount	47
Net change in income taxes	(206)
Purchases of reserve in place	33
Sales of reserves in place	(83)
Changes in timing and other	(1)
Balance December 31, 2010	697

(1) Excludes the original purchase of 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 2010 and 2009 are as follows:

	2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 70,148	$ 68,622	$ 80,267	$ 89,393
Operating income	16,079	15,776	20,615	19,069
Net income (loss)	7,263	4,312	8,850	(1,379)
Basic earnings (loss) per share	0.14	0.08	0.17	(0.02)
Diluted earnings (loss) per share (1)	0.14	0.08	0.17	(0.02)

	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 (loss) income	(375,177)	12,820	14,788	20,851
Net (loss) income	(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 (1)	(4.68)	0.08	0.11	0.19

(1) Because the Company recognized a net loss for the quarters ended December 31, 2010 and March 31, 2009, 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).

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, 2010. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2010, 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 our 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, 2010 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, 2010, 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, 2010, 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.

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Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2010, we implemented a financial management and reporting module to the existing accounting software. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included procedures to preserve the integrity of the data converted and a review by management to validate the data converted. Additionally, we provided training related to the financial reporting system software to individuals using the financial reporting system to carry out their job responsibilities, as well as to those who rely on the financial information. We anticipate that the implementation of this module will strengthen the overall systems of internal controls due to enhanced automation and integration of related processes. We are modifying the design and documentation of internal control process and procedures relating to the new module to supplement and complement existing internal control over financial reporting. The system changes were undertaken to integrate systems and consolidate information and were not undertaken in response to any actual or perceived deficiencies in our internal control over financial reporting. Testing of the controls related to this new system is ongoing and is included in the scope of our assessment of our internal control over financial reporting for 2010.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

Item 9B. Other Information

None.

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 2011 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 2011 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 2011 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 2011 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 2011 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 43 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 3.1 to the Company's Current Report on Form 8-K filed on December 10, 2010 (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)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.3	Form of the 9.500% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
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, effective January 1, 2011.
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)).

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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)).
10.44	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)).
10.46	Second Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.48 *	Third Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
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)).
10.45	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)).
10.47	Second Amendment to Amended and Restated Second Lien Term Loan, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
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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)).

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10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
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)).
10.39 †	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 (incorporated herein by reference to Exhibit 10.42 to the Company’s Annual Report on Form 10-K filed on February 26, 2010 (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 Randy L. Limbacher in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Periodic Financial Reports by Michael J. Rosinski in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Periodic Financial Reports by Randy L. Limbacher and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350
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 25, 2011.

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

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, Chief Executive Officer and President (Principal Executive Officer)	February 25, 2011
/s/ Michael J. Rosinski Michael J. Rosinski	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 25, 2011
/s/ W. Rufus Estis W. Rufus Estis	Vice President and Controller (Principal Accounting Officer)	February 25, 2011
/s/ D. Henry Houston D. Henry Houston	Lead Director	February 25, 2011
/s/ Richard W. Beckler Richard W. Beckler	Director	February 25, 2011
/s/ Matt Fitzgerald Matt Fitzgerald	Director	February 25, 2011
/s/ Philip L. Frederickson Philip L. Frederickson	Director	February 25, 2011
/s/ Josiah O. Low, III Josiah O. Low, III	Director	February 25, 2011
/s/ Donald D. Patteson, Jr. Donald D. Patteson, Jr.	Director	February 25, 2011

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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.

Unconventional resource. A term used in the oil and natural gas industry to refer to a play in which the targeted reservoirs generally fall into one of four categories: (1) tight sands, (2) coal beds, (3) gas shales, or (4) oil shales. These reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to product economic flow rates.

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 3.1 to the Company’s Current Report on Form 8-K filed on December 10, 2010 (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)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on April 19, 2010 (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)).
10.45	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)).
10.47	Second Amendment to Amended and Restated Second Lien Term Loan, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.49 *	Third Amendment to Amended and Restated Second Lien Term Loan, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
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)).

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10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
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)).
10.39 †	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 (incorporated herein by reference to Exhibit 10.42 to the Company's Annual Report on Form 10-K filed on February 26, 2010 (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 Randy L. Limbacher in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Periodic Financial Reports by Michael J. Rosinski in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Periodic Financial Reports by Randy L. Limbacher and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350
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.