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

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

FORM 10-K

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

For The Fiscal Year Ended December 31, 2009

OR

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

Commission File Number: 000-51801

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer x
Non-Accelerated filer o	Smaller Reporting Company o
(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

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

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

Documents Incorporated By Reference

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

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

Part I

Items 1 and 2. Business and Properties

General

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

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

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

Our Strategy

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

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

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

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

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

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

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

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

Our Strengths

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

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

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

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

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

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

Our Operating Areas

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

California

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

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

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

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

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

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

Rockies

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

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

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

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

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

South Texas

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

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

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

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

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

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

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

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Other Onshore

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

Texas State Waters

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

Gulf of Mexico

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

Title to Properties

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

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

Crude Oil and Natural Gas Operations

Production by Operating Area

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

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

Total	44.5	620.1	393.9	50.6

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

Proved Reserves

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

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

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

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

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

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

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

Estimated Proved Reserves at December 31, 2009 (1)(2)

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

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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. (hereafter "NSAI"), independent petroleum engineers. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates" and Item 8. "Financial Statements and Supplementary Data - Supplemental Oil and Gas Disclosures." NSAI's report is attached as Exhibit 99.1 to this Form 10-K.

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

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

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

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

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

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

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

Internal Control

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

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

Qualifications of Third Party Engineers

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

2009 Capital Expenditures

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

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

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

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

Productive Wells and Acreage

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

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

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

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

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

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

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

Drilling Activity

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

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

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

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

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

Marketing and Customers

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

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

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

Major Customers

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

Competition

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

Seasonal Nature of Business

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

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Government Regulation

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

Exploration and Production Regulation

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

Environmental Regulation

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

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

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

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

Hydraulic Fracturing. Congress is also considering legislation that would repeal the current exemption in the Safe Drinking Water Act's underground injection control program