Rosetta Resources Inc.
Form 10-K
April 20, 2006
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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, 2005**

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

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

None

SECURITIES LISTED PURSUANT TO SECTION 12(g) OF THE ACT:

Common Stock, $.001 Par Value	**Nasdaq National Market**
(Title of Class)	**(Name of Exchange on which registered)**

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1933. Yes ¨ No x

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ 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 ¨ No x

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 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. x

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer as defined in Rule 12b-2 of the Securities Exchange Act of 1934.

¨ Large accelerated filer ¨ Accelerated filer x Non-Accelerated filer

Indicate by check mark whether the registrant is a shell company as defined by Rule 12b-2 of the Securities Exchange Act of 1934. Yes ¨ No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of April 10, 2006 was approximately $934 million based on the closing price of $18.55 per share on the Nasdaq National Market.

The number of shares of the registrant s Common Stock, $.001 par value per share outstanding as of April 10, 2006 was 50,587,269.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III will either be included in Rosetta Resources Inc. definitive proxy statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

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Cautionary Note

This annual report contains forward-looking statements of our management 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, although made in good faith, 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 Forward-Looking Statements in Item 7. 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 gas terms, see page 119.

PART I

Item 1. Business.

GENERAL

Rosetta Resources Inc. (the Company) is comprised of the domestic oil and natural gas business formerly owned by Calpine Corporation and affiliates (predecessor, Calpine) acquired in July 2005 by the Company (successor). The Company is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States, and operates in one business segment. Our operations are primarily concentrated in the Sacramento Basin of California, Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico and the Rocky Mountains. The Company was formed in June 2005 to acquire the domestic oil and natural gas business of Calpine. This acquisition closed in July 2005.

Pursuant to the acquisition, we entered into several operative contracts with Calpine, including a purchase and sale agreement under which we have indemnification rights and obligations with respect to Calpine. Currently, Calpine provides pipeline services, including personnel, under the transition services agreement and markets our gas under a marketing agreement. We sell a significant portion of our gas to Calpine pursuant to certain gas purchase and sales contracts.

In October 1999, Calpine purchased Sheridan Energy, Inc. (Sheridan), a natural gas exploration and production company operating in northern California and the Gulf Coast region. The Sheridan acquisition provided the initial management team an operational infrastructure to evaluate and acquire oil and natural gas properties for Calpine. In December 1999, Calpine purchased Vintage Petroleum, Inc. s interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. Sheridan was purchased by Calpine in 1999 and renamed Calpine Natural Gas Company and then was merged into Calpine in April 2002, and Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.; RROLP) was subsequently established. In October 2001, Calpine completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation, a natural gas exploration and production company with operations in south Texas. In September 2004, Calpine sold its natural gas reserves in the New Mexico San Juan Basin and Colorado Piceance Basin and such properties have been reflected as discontinued operations for all periods presented herein. Several members of the Calpine management team, who were responsible for operating Calpine s oil and natural gas business, joined the Company concurrently with the acquisition of the properties from Calpine.

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OUR STRENGTHS

We believe our historical success is, and future performance will be, directly related to the following combination of strengths:

High Quality, Diversified Asset Base. We own a geographically diversified asset base comprised of long-lived reserves along with shorter-lived, higher return reserves. Approximately 96% of our reserves are natural gas, and almost all of our assets are located in the Sacramento Basin of California, South Texas, the Gulf of Mexico and the Rocky Mountains. We believe this geographic and production profile diversity will enhance the stability of our cash flows while providing us with a large number of development and exploration opportunities, as well as support for additional acquisitions.

Development and Exploration Drilling Inventory. We have identified over 500 drillable, low to moderate risk opportunities providing us with multiple years of drilling inventory, and we expect to drill approximately one-third of these locations during 2006. Approximately 123 of these locations are classified as proved undeveloped. We also have a large and diversified portfolio of what we designate as development and exploration prospects. Our capital expenditure budget, including potential acquisitions, is approximately $199 million for 2006. We will manage our exploratory risks and expenditures by selectively reducing our capital exposure in certain high risk projects by partnering with others in our industry.

Operational Control. We operate approximately 90% of our estimated proved reserves, which allows us to more effectively manage expenses and control the timing of capital allocation of our development and exploration activities.

Experienced Management Team. Our executive management has an average of over 25 years of experience in the oil and natural gas industry.

Proven Management Team, Including Technical and Land Personnel, with Access to Technological Resources. Our technical staff includes 26 geologists, geophysicists, landmen, engineers and technicians with an average of over 20 years of relevant technical experience. Our staff has a proven record of 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, conducting Gulf of Mexico operations and managing horizontal drilling and coalbed methane operations. These core competencies helped us to achieve a drilling success rate of over 80% for the six months ended December 31, 2005 and has helped maximize recovery from our reservoirs. Our definition of drilling success is a well that produces hydrocarbons at sufficient rates, to allow us to recover, at a minimum, our capital investment and operating costs.

OUR STRATEGY

Our strategy is to increase stockholder value by profitably increasing our reserves, production, cash flow and earnings using a balanced program of (1) developing existing properties, (2) exploring undeveloped properties, (3) completing strategic acquisitions and (4) maintaining financial flexibility. The following are key elements of our strategy:

Further Development to Existing Properties. We intend to further develop the significant remaining upside potential of our properties by working over existing wells, drilling infill locations, drilling step-out wells to expand known field outlines, tapping logged behind pipe pays and lowering field line pressures for additional recoveries. Many of these opportunities were not fully exploited prior to the formation of Rosetta.

Exploration Growth. We intend to focus on niche areas in which we have technological and operational advantages. This growth will come from higher-risk, higher-impact opportunities offshore in the Gulf of Mexico, along the Wilcox Trend in South Texas, in deep horizons in the Sacramento Basin, and from lower-risk, longer-lived drilling in the shallow Sacramento Basin, the Lobo Sand Trend in South Texas, the Wasatch and Mesa

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Verde formations in the Uinta Basin, Niobrara chalk in the DJ Basin and coalbed methane in the San Juan Basin. While the majority of our prospects will be internally generated, we will, from time to time, participate in third party drilling opportunities.

Acquisition Growth. We will continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We will particularly focus on opportunities where we believe our reservoir management and operational expertise will enhance the value and performance of acquired properties. Initial acquisition targets will be in and around our major producing and activity areas. We will also use our minor producing field ownerships as islands of control and knowledge to make strategic acquisitions. Our management team has demonstrated success in acquisitions in the past ten years and has developed a significant knowledge base of producing oil and natural gas fields throughout the United States.

Maintain Technological Expertise. We intend to maintain the technological expertise that helped us to achieve a drilling success rate of over 80% for the six months ended December 31, 2005 and helped us maximize field recoveries. We will use advanced geological and geophysical technologies, detailed petrophysical analyses, state-of-the-art reservoir engineering and sophisticated completion and stimulation techniques to grow our reserves and production.

Endeavor to be a Low Cost Producer. We will strive to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate operating control and capture operating efficiencies. This is particularly true in the Sacramento Basin because of our position as the dominant producer in the region.

Maintain Financial Flexibility. We intend to optimize unused borrowing capacity under our revolving line of credit by periodically refinancing our bank debt in the capital markets when conditions are favorable. As of December 31, 2005, we had $160 million available for borrowing under our revolving line of credit. Additionally, we expect internally generated cash flow to provide additional financial flexibility, allowing us to pursue our business strategy. We intend to actively manage our exposure to commodity price risk in the marketing of our oil and natural gas production. As part of this strategy and in connection with our credit facilities, we entered into natural gas fixed-price swaps for a significant portion of our expected production through 2009. Additionally, in the fourth quarter 2005, we entered into costless collar contracts for a portion of our 2006 production. We may enter into other agreements, including fixed price, forward price, physical purchase and sales contracts, futures, financial swaps, option contracts and put options.

CALPINE BANKRUPTCY

On December 20, 2005, Calpine and certain of its subsidiaries, including Calpine Fuels, filed for federal bankruptcy protection in the Southern District of New York. The filing raises certain concerns regarding aspects of our relationship with Calpine which we will closely monitor as the Calpine bankruptcy proceeds. Following are our principal areas of concern:

- The bankruptcy court may challenge the fairness of our acquisition. For a number of reasons, including the process which Calpine followed in allowing market forces to set the purchase price for the acquisition, we believe that it is unlikely that any challenge to the fairness of our acquisition would be successful.

- The bankruptcy proceeding may prevent, frustrate or delay our ability to receive record legal title to certain properties originally determined to be non-consent properties which we are entitled to obtain under our purchase and sale agreement with Calpine and certain subsidiaries.

- Additionally, the bankruptcy proceeding may prevent, frustrate or delay our ability to receive corrective documentation from Calpine for certain properties which we bought from Calpine and paid for, where the documentation delivered by Calpine was incomplete, including documentation related to certain ministerial governmental approvals.

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- Calpine may stop purchasing gas from us under our gas purchase contract with Calpine. Since the date of the bankruptcy filing, Calpine has continued buying natural gas from us and paying for it timely. The bankruptcy court for Calpine, as debtor-in-possession, has given approval to continue payments to us for our delivery of natural gas under our gas purchase and sale agreement. Under the terms of this contract, we are entitled to sell this gas to third parties at comparable prices and terms if this occurs and expect to be able to minimize our exposure to four days of sales under the contract, or approximately $1.4 million in lost sales at production rates and prices as of December 31, 2005.

- Calpine may stop providing us certain services, including natural gas marketing services and pipeline services, which Calpine, through separate subsidiaries, currently provides to us. Management does not believe that cessation of these services would have a material impact on our operations.

As to all of these matters, see also Risk Factors Risks Relating to Our Business Calpine s recent bankruptcy filing may adversely affect us in several respects for a further discussion of the potential risks relating to Calpine s bankruptcy. We have engaged bankruptcy counsel to monitor this proceeding and advocate our interests as necessary and have initiated plans to mitigate the operational risks presented by the Calpine bankruptcy.

We believe the structure of the equity offering of our common stock and the process followed by Calpine allowed market action to determine the $1.05 billion in proceeds, before fees and expenses, received by Calpine in the acquisition. Senior management of Calpine, in consultation with its various advisors, structured the acquisition and the private issuance of our common stock to fund the acquisition. Our equity was purchased by sophisticated investors knowledgeable in oil and natural gas transactions.

Transfers Pending at Calpine s Bankruptcy

At July 7, 2005, we retained approximately $75 million of the purchase price in respect to properties identified as requiring third party consents that were not received before closing. Subsequent analysis determined that a portion of these properties, with an approximate allocation value of $29 million, under the purchase and sale agreement with Calpine (PSA) did not require consent. For that portion of the properties for which third party consents were in fact required having an approximate value of $39 million under the PSA and those properties that did not require consent, we believe that Calpine was obligated to have transferred to us the record title, free of any mortgages, for all properties for which any required consents were received or were otherwise cured at the close of each month for the first six months after closing by no later than 5 days after the end of each month of cure.

The approximate allocated value under the PSA for the portion of these properties subject to a preferential right is $7.1 million. We will retain $7.4 million for the properties subject to this preferential right, which total amount includes approximately $0.3 million for a property which was transferred to us but will be transferred to the appropriate third party under an exercised preferential purchase right.

We believe all conditions for our receipt of record title, free of any mortgages for all of these properties (excluding that portion of these properties subject to this preferential right) were satisfied on or before December 15, 2005. We believe we are the equitable owner of all of these properties (excluding that portion of these properties subject to this preferential right) and that same are not part of Calpine s bankruptcy estate. Upon our receipt from Calpine of record title, free of any mortgages, we are prepared to pay Calpine approximately $68 million, subject to appropriate adjustment for the associated net revenues for the cured non-consent properties through December 15, 2005. Rosetta s statement of operations for the six months ended December 31, 2005 does not include any net revenues or production from these properties (excluding that portion of these properties subject to this preferential right).

If Calpine does not provide us with record title, free of any mortgages for all of these properties (excluding that portion of these properties subject to this preferential right), we will have a total of approximately $68 million available to us for general corporate purposes, including for the purpose of acquiring additional

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properties. We will also have approximately $7.4 million for that portion of these properties subject to a preferential right, available to us for general Corporate purposes, including for the purpose of acquiring additional properties.

In addition, as to certain of the properties we purchased from Calpine and paid Calpine for on July 7, 2005, we will seek additional documentation from Calpine to eliminate any issue as to the clarity of our ownership. The specific nature of our request will depend on the particular facts and circumstances surrounding each property involved. Certain of these properties are subject to ministerial governmental action approving us as qualified assignee and operator, even though in most cases Calpine specifically conveyed the property to us free and clear of mortgages and liens previously recorded by Calpine s creditors. As to certain other properties, the documentation delivered by Calpine at closing was incomplete. We remain hopeful that we will be able to work cooperatively with Calpine to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all these properties, Calpine contractually agreed to provide us with such further assurances as we may reasonably request. Nevertheless, as a result of the recency of Calpine s bankruptcy filing, it remains uncertain as to how, when and if Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these conveyancing issues, we will pursue all available remedies, including but not limited to a declaratory judgment to enforce our rights and actions to quiet title. After pursuing these matters, if we experience a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to us, an outcome our management considers to be remote, then we could experience losses which could have a material adverse effect on our assets, financial condition, earnings and statement of cash flows.

RESTATEMENT OF FINANCIAL RESULTS FOR THIRD QUARTER 2005

In connection with the preparation of our audited financial statements for the six-months ended December 31, 2005, we determined that certain costs of $1.1 million incurred in connection with our issuance of common stock in the third quarter 2005 were incorrectly accounted for as a reduction of the proceeds from such issuance in additional paid-in capital on our balance sheet and should initially have been accounted for as operating expenses on our income statement. In addition, we had over accrued certain costs of $0.1 million in additional paid-in capital. As a consequence, we have restated our financial results for the fiscal quarter ended September 30, 2005, as included in the Selected Data Quarterly Information included herein, from what we previously disclosed in our registration statement on Form S-1 (333-128888), specifically in our Selected Financial Data, our Historical Unaudited Pro Forma Financial Data, and our unaudited consolidated financial statements as of September 30, 2005 and for the three months ended September 30, 2005.

The changes to correct the error are as follows:

- General and administrative costs are increased by $1.1 million;
- Net income for third quarter 2005 is reduced by $1.1 million to $8.2 million; and
- Earnings per share basic and diluted are reduced by $0.03 and $0.02 to $0.16 and $0.16 per share, respectively.
- Additional paid-in Capital is increased by $1.1 million to $748.6 million;
- Retained earnings are reduced by $1.1 million to $8.2 million.

See Selected Data Quarterly Information for the restated financial data.

OUR OPERATING AREAS

We own, subject to the pending transfers above, producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas,

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the Gulf of Mexico, the Rocky Mountains and Other located in various geographical areas in the United States. In each area, we are pursuing geological objectives and projects that are consistent with our technical expertise. Our strength and strategies, as discussed above, which include this technical expertise, are concentrated in these particular areas and fields in order to provide the highest potential economic returns. Since the date of our acquisition, we have drilled 29 gross and 19.8 net wells, of which 83% found commercial quantities of production. The following is a summary of our major operating areas in which we discuss their various characteristics. With respect to acreage information in this report, we have included acreage relating to properties which were not transferred to us on the original date of acquisition because consents to transfer had not been obtained at that time. That information is not available without undue time and expense as of the date of this report.

California-Sacramento Basin

Rio Vista Field and Surrounding Area. 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, 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 3.6 Tcfe of natural gas reserves to date since its discovery in 1936. The California Energy Commission assigns 419 Bcf of remaining reserves to Rio Vista field. We currently produce or have behind-pipe reserves in over 16 different zones at depths ranging from 2,500 feet to 9,600 feet in the field. The natural gas field trap is a faulted, downthrown rollover anticline, elongated to the northwest. The current productive area is approximately ten miles long and nine miles wide. A majority of the reservoirs are depletion driven with long production histories. For the six months ended December 31, 2005 (the period after our acquisition), the average net daily production in the Sacramento Basin was approximately 29 MMcfe/d from 167 producing wells. As of December 31, 2005, we owned approximately 62,000 net acres in the Rio Vista Field and surrounding Sacramento Basin areas. We are the single largest producer and leaseholder in the basin. Our acreage in the basin holds significant low-risk, low-cost upside potential in 140 currently shut-in or idle wells, 34 proved drilling locations, and numerous workover and recompletion projects. Additional reserve potential exists in gathering system optimization projects, numerous fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

Sacramento Valley Extension. We believe our existing land position and financial strength will give us the ability to rapidly expand our Sacramento Basin operations. The Sacramento Valley Extension Project is an extension of work and study done in the redevelopment of the Rio Vista Field and non-operated drilling in nearby reservoirs. Numerous plays are being evaluated, including Mokelumme gorge traps and McCormick fault traps, deeper Winters traps, and shallow Emigh/Capay truncation traps on the east side of the Sacramento Basin. Subtle low contrast and low resistivity pays in the Emigh, Capay, Hamilton and Martinez formations are being pursued for under-exploited and unrecognized potential. Over 50 leads and prospects have been catalogued to date and we have identified more than 80 wells which we believe contain bypassed pay. We have approximately 520 square miles of 3-D seismic data and over 1,800 miles of 2-D seismic data in Rio Vista, the extension area, and the greater Sacramento Valley. The area contains 16 prospective producing formations with historically high production rates at shallow to moderate drill depths. These characteristics, along with an expedited regulatory and permitting process, high reserves per well, and a strong local natural gas market should provide for attractive returns on investments.

Other Activities. We are actively pursuing additional lease acquisitions. Since the date of acquisition, we have added 12,658 acres to our leasehold inventory and are in the process of leasing an additional 9,500 acres. We have contracted drilling rigs which has allowed us to drill seven of the 40 wells in the 2005-2006 drilling program since November 2005 with a 100% success rate. Of the remaining 33 wells to be drilled, three are deep wells below 10,000 feet, one of which is currently in progress. There is one completion rig currently working on Rosetta properties in the Rio Vista Field area, and it has performed 14 recompletions since June 30, 2005. We will add a second completion rig during the second quarter of 2006 to help with the remaining 33 recompletions that are planned for 2006.

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Lobo

Lobo Trend. Discovered in 1973, the Lobo Trend of South Texas is a complex, highly faulted sand that has produced over 7 Tcf of natural gas. The Lobo section produces from tight sands with low permeabilities and high pressures at depths of 7,500 to 10,000 feet. We are a significant producer in the Lobo Trend, with over 60,000 net acres, 81 square miles of 3-D seismic, approximately 220 active operated wells and interests in approximately 100 non-operated wells. We recently added a very prospective 4,500 net acre position in the heart of the Lobo play. For the six months ended December 31, 2005, our average net production from the Trend was 21 MMcfe/d. Our working interests range from 50% to 100%. We have identified 84 potential drilling locations on our acreage.

We completed 41 workover projects in 2005. Additional compression is being put in place to accommodate the expected increase in gas production as a result of these well work projects. We have two drilling rigs under contract and we plan to drill 15 wells in the Trend in 2006.

Perdido

Perdido Sand Trend. We own a 50% non-operating working interest in approximately 20,000 acres in the Perdido Sand Trend. The Perdido Sands are in isolated fault blocks and are stratigraphically trapped below the Upper Wilcox structures. The Perdido section is comprised of tight natural gas sands requiring significant fracture stimulation. Horizontal drilling has been very successful in maximizing natural gas recovery. The primary potential in the Perdido is from 9,500 to 12,000 feet. For the six months ended December 31, 2005, our average net daily production was 8.2 MMcfe/d from 27 producing wells. Since June 30, 2005, 48 additional locations have been identified and three successful wells have been drilled. We plan to drill 10 wells in 2006.

Gulf of Mexico

Federal Waters. Subject to pending MMS approval of the conveyances made by Calpine to us at closing, we own and believe we have satisfied the regulators requirements to earn operating rights in seven blocks in the Gulf of Mexico. For the six months ended December 31, 2005, our average net production from these blocks was 5.4 MMcfe/d, which was affected by Hurricanes Katrina and Rita. As the recovery process from the hurricanes nears completion, our average net production from these blocks was 12.3 MMcfe/d for February 2006. We have operated and non-operated working interests in these blocks ranging from 20% to 100%. Production from these working interests represents approximately 10% of Rosetta s total current production.

We have entered into an area of mutual interest agreement in which we have the right to participate in up to a 50% working interest in wells within 150 OCS blocks on the Louisiana offshore shelf. Over the next three years, we intend to participate in the drilling of at least ten new prospects in these blocks.

Through our participation in a joint venture, we have contracted to acquire a 25% non-operated working interest in two offshore blocks, Main Pass Block 118 and Main Pass Block 117. Main Pass Block 118 well No. 1 was drilled, production casing set, successfully tested and is awaiting platform installation. The Block 117 well No. 1 will spud in the first half of 2006.

State Waters of Texas

We are exploring in the Vicksburg and Frio trends in Galveston Bay, Texas, specifically pursuing sands that exhibit strong hydrocarbon indicators on 3-D seismic. In January 2005, we drilled and operated a discovery well in the Vicksburg Sand. Two additional intervals are present in the well, which have log characteristics that indicate productive zones. We expect to acquire and drill two to three prospects in this trend in the next 12 months with additional wells planned in 2007.

We have acquired a 7% non-operating working interest in the TB-2 prospect in Galveston Bay. The State Tract 251 well No. 5 completed drilling in February 2006 and tested at 4.9 MMcfe/d.

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We will participate in an additional exploratory well which we will begin drilling in the first quarter of 2006.

Other Onshore

Live Oak County Prospect. Through the interpretation of 3-D seismic data, we have identified four structures at approximately 16,500 feet in the Sligo Reef Trend in Live Oak County, Texas. Two of these structures were previously drilled and produced by other operators. One structure has produced 33 Bcfe since 1983 from one well on the south end of our 3-D data coverage, and a second structure on the north end of our data coverage produced 12 Bcfe since 1987, also from one well. We currently have approximately 2,500 net acres under lease and plan to obtain a suitable industry partner(s) to join in the drilling of the initial test well to evaluate our prospect.

Frio, Vicksburg, Yegua and Wilcox Trends. In the Frio Trend, the Dunn Peach discovery well was drilled in 2004 on Padre Island in Kleberg County, Texas. Two more development wells and one exploratory dry hole were drilled in 2005. A fifth well was drilled and logged in December 2005 and is currently on production. Two additional development wells will be drilled in 2006. In Colorado County, we are pursuing amplitude plays between 3,500 and 7,000 feet in the Frio and Yegua trends. In the Wilcox, we are pursuing normally pressured structural closures at 10,000 feet and over-pressured closures from 14,000 to 17,500 feet. All of these projects are based on high quality 3-D seismic data. As of December 31, 2005, we have eight prospects in the Frio, Yegua and Upper Wilcox trends of Colorado County, Texas, with six wells expected to be drilled within the next twelve months. We are pursuing numerous additional opportunities in these trends.

Colorado County Prospect. In January 2006, we completed drilling a lower Wilcox prospect in Colorado County, Texas, which resulted in a dry hole.

Rocky Mountains

We are active in the DJ, Uinta and the San Juan Basins in the Rocky Mountains.

DJ Basin, Colorado. As of December 31, 2005, we had a majority working interest in approximately 52,000 net acres, identified 17 drillable, 3-D seismic-supported, 80-acre locations on these lands that have been approved for 40-acre spacing and drilled 16 other locations during the year. We expect to drill approximately 213 additional locations on our existing leases and other leases currently under negotiation with 70 wells planned for 2006. Additional leasing has added approximately 18,500 acres to our land position.

By December 31, 2005, we had acquired 17.1 square miles of 3D seismic data with an additional 38 square miles currently in the process of acquisition. We are using 3-D seismic data as a critical tool in identifying potential drilling opportunities. We recently upgraded the gathering infrastructure and installed new 4 and 6 production lines with compression to enlarge the gathering system and allow us to deliver larger volumes of gas.

Uinta Basin, Utah. We are pursuing plays in the Uinta Basin in the emerging Mesa Verde and Wasatch basin-centered natural gas play in eastern Utah. This play is similar to that in the adjacent Piceance Basin, where we had significant success in the past. Average producing depth is approximately 6,500 feet. As of December 31, 2005, we own a 100% working interest in approximately 2,800 net acres as a result of the acquisition of an additional 626 net acres in the Utah State lease sale. We have identified 35 drillable locations and plan to drill six wells in 2006.

San Juan Basin, New Mexico. The San Juan Basin is the second most prolific gas basin in North America, according to published articles, with 34 Tcf of production, 14 Tcf of which comes from the Fruitland Coal CBM (Coal Bed Methane). There is Fruitland Coal production from depths of 1,600 feet surrounding our leasehold. We are pursuing this coalbed methane play and had, as of December 31, 2005, a 100% working interest position

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in approximately 6,800 acres. Since then, 640 acres have been added to our leasehold in this play. The well permitting process is underway and we plan to begin our 26-well program by the middle of this year. We have identified 44 drillable locations on our San Juan Basin leases.

Texas Panhandle Price Ranch Project. On February 10, 2006, we acquired a farmout from BP on approximately 12,800 acres in Sherman County, Texas, to explore for oil and gas reserves in the Marmaton Limestone and Morrow Sandstone. The acreage is held by production by shallower Chase Formation Hugoton gas production. The farmout includes access to a proprietary BP 22 square miles of 3D seismic survey, which is being reprocessed for prospect development. We recently acquired a 3.5-mile 2D seismic line to evaluate several well locations offsetting existing Marmaton production. Further seismic and geologic evaluations are ongoing.

CRUDE OIL AND NATURAL GAS OPERATIONS

Production by Operating Area

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

	Successor(1) Six Months Ended December 31, 2005			Predecessor Six Months Ended June 30, 2005		
	Natural Gas (Bcf)	Oil (MMBbls)	Equivalents (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	Equivalents (Bcfe)
California	5.2		5.3	6.5		6.6
Lobo	3.8		3.9	3.7	0.0	3.9
Perdido	1.5		1.5	1.8	0.0	1.8
State Waters	0.7		0.7	0.3		0.3
Gulf of Mexico	0.4	0.1	1.0	1.1	0.1	1.5
Other Onshore	0.7	0.1	0.9	1.0	0.1	1.3
Rocky Mountains						
Mid-Continent	0.1		0.2	0.1		0.1
Totals	12.4	0.2	13.5	14.5	0.2	15.5

(1) Excludes properties not conveyed as part of the acquisition of the domestic oil and natural gas properties of Calpine, as described in the footnotes on the next page.

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 can not 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, 2005, we had 359 Bcfe of proved oil and natural gas reserves, including 344 Bcf of natural gas and 2,481 MBbls of oil and condensate. Using prices as of December 31, 2005, the estimated present value of future net revenues from proved reserves before income taxes, using SEC pricing guidelines, and

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discounted at an annual rate of 10% was approximately $1.3 billion. The following table sets forth by operating area a summary of our estimated net proved reserve information as of December 31, 2005:

	Estimated Proved Reserves at December 31, 2005(1)(3)(4)				
	Developed (Bcfe)	Undeveloped (Bcfe)	Total (Bcfe)	Percent of Total Reserves	PV-10 (Millions)(2)
California	110.5	37.2	147.7	41%	$ 605.7
Lobo	74.0	77.2	151.2	42%	463.1
Perdido	9.2	1.0	10.2	3%	44.1
State Waters	3.4		3.4	1%	17.8
Gulf of Mexico	12.7	3.9	16.6	5%	99.6
Other Onshore	15.9	7.7	23.6	6%	76.5
Rocky Mountains	2.5	1.0	3.5	1%	9.7
Mid-Continent	2.3	0.5	2.8	1%	10.2
Total	230.5	128.5	359.00	100%	$ 1326.7

(1) These estimates are based upon a reserve report prepared by Netherland Sewell & Associates, Inc. (hereafter Netherland Sewell) using criteria in compliance with SEC guidelines and excludes 19.6 Bcfe of proved oil and gas reserves and a value of $72.5 million representing the total allocated value of wells and the associated leases described in footnote 3 below.

(2) Our PV-10 value has been calculated using a spot market natural gas price and posted oil price at December 31, 2005 of $10.08/MMBtu and $57.75/Bbl, respectively, adjusted for basis differentials and held flat for the life of the reserves and adjusted for quality differentials.

(3) At the July 2005 closing, we withheld $68 million for properties (excluding that portion of the properties subject to the preferential right) which Calpine agreed to transfer to us as part of the acquisition but for which Calpine had not then secured consents to assign. Subsequent analysis determined that a portion of these properties, having an allocated value withheld under the PSA at closing of $29 million, did not require consent. Consents now have been received for the remaining properties as to which the allocated value under the PSA withheld at closing, was $39 million (Cured Non-consent Properties). We are prepared to pay Calpine the retained portion of the original purchase price, upon our receipt from Calpine of record title on these properties, free of any encumbrance, subject to appropriate adjustment for the net revenues through December 15, 2005 related to these properties.

(4) Includes properties subject to additional documentation or completion of ministerial actions by federal or state agencies necessary to perfect title issues discovered during routine post-closing analysis after completion of our acquisition of the domestic oil and natural gas business from Calpine, for which Calpine is contractually obligated to assist in resolving.

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Operating Data

The following table presents certain information with respect to our production and operating data for the periods presented, all of which is domestic production.

	Successor	Predecessor		
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Years Ended December 31, 2004	2003
Production				
Natural gas (Bcf)	12.4	14.5	37.3	49.6
Oil (MMBbls)	0.2	0.2	0.6	0.4
Equivalents (Bcfe)	13.5	15.5	40.9	52.2
Average realized sales price per unit				
Natural gas ($/Mcf)(1)	$ 9.57	$ 6.59	$ 6.02	$ 5.38
Oil ($/Bbl)	$ 59.52	$ 49.86	$ 39.05	$ 29.67
Equivalents ($/Mcfe)	$ 8.38	$ 6.70	$ 6.06	$ 5.36
Expenses ($/Mcfe)				
Lease operating expense(2)	$ 1.16	$ 1.08	$ 0.75	$ 0.57
Transportation, treating and marketing fees	$ 0.20	$ 0.19	$ 0.13	$ 0.15
General and administrative, net(3)	$ 1.09	$ 0.63	$ 0.48	$ 0.32
Depreciation, depletion and amortization (excluding ceiling test write-downs and impairment)	$ 3.00	$ 1.98	$ 2.00	$ 1.39

(1) The average realized natural gas sales price per Mcf inclusive of the effects of hedging for the six months ended December 31, 2005 was $8.23. There were no other hedging arrangements during any other period presented.

(2) The six months ended December 31, 2005 (successor) includes workover expense, ad valorem taxes and insurance of $0.22 per Mcfe, $0.25 per Mcfe and $0.04 per Mcfe, respectively. The high rate of workover expense relates to the workover of our High Island #A-442 well and an aggressive rehabilitation program to boost production on existing wells. The six months ended June 30, 2005 (predecessor) includes workover expense, ad valorem taxes and insurance of $0.22 per Mcfe, $0.22 per Mcfe, and $0.06 per Mcfe, respectively. Ad valorem taxes for the six months ended June 30, 2005 (predecessor) includes higher taxes in South Texas and a special reclamation tax in California. Lease operating expense for 2004 (predecessor) includes workover expense and ad valorem taxes of $0.04 per Mcfe and $0.15 per Mcfe, respectively. Lease operating expense for 2003 (predecessor) includes workover expense and ad valorem taxes of $0.04 per Mcfe and $0.09 per Mcfe, respectively.

(3) Net of overhead reimbursements received from other working interest owners.

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2005 Capital Expenditures

The following table summarizes information regarding historical capital expenditures for the six months ended December 31, 2005 (successor), the six months ended June 30, 2005 (predecessor) and the historical capital expenditures for the year ended December 31, 2004 (predecessor).

	Successor	Predecessor	
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004
		(In thousands)	
Development capital expenditures:			
Sacramento Basin	$ 3,930	$ 4,166	$ 6,025
Lobo	6,775	2,001	8,670
Perdido	9,268	10,874	7,422
Texas State Waters	2,499		
Other Onshore	3,833	1,337	5,164
Gulf of Mexico	2,947	246	1,813
Rocky Mountains	3,035	965	
Mid-Continent	317	220	300
Total development capital expenditures	32,604	19,809	29,394
Exploration capital expenditures:			
Exploration activities:			
Sacramento Basin	3	406	2,214
Lobo		19	
Perdido		1,567	11,261
Texas State Waters	524	3,417	
Other Onshore	6,998	963	3,043
Gulf of Mexico	6,422	4,310	2,361
Rocky Mountains		137	
Mid-Continent			
Leasehold	9,224	2,617	3,559
New acquisitions	5,524		
Delay rentals	143	443	507
Geological and geophysical/Seismic	5,659	513	199
Total exploration capital expenditures	34,497	14,392	23,144
Total capital expenditures(1)	$ 67,101	$ 34,201	$ 52,538

(1) The amount for 2004 (predecessor) excludes $1.3 million of capitalized interest, $3.1 million of overhead, $10.0 million of compressor station and gathering system expense and $1.4 million for acquisition properties. Our total capital expenditures in 2004 of $52 million, including these exclusions, corresponds to 2004 total capital costs of $69 million as defined under Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies in the Supplemental Oil and Gas Disclosure under Item 8 of this report. The six-month period ended June 30, 2005 (predecessor) excludes $(0.7) million of capitalized interest and $1.7 million of overhead. Capital expenditures for the six months ended December 31, 2005 (successor) excludes capitalized interest of $0.6 million, corporate other of $1.6 million and geological and geophysical costs of $1.7 million. Corporate other consists of corporate costs related to IT software/hardware, office furniture and fixtures and license transfer fees.

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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, 2005. 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(1)		Developed Acres(1)		Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
California	28,266	23,362	47,160	38,646	185	173
Colorado	65,724	54,322	774	640	18	18
Montana	41,190	38,721	255	240	2	1
Offshore(3)	5,512	5,000	23,996	21,765	15	12
Texas	46,635	24,007	95,022	48,916	503	252
Wyoming	38,137	37,539	2	2		
Other(2)	81,465	76,375	30,883	8,543	99	31
Total	306,929	259,326	198,092	118,752	822	487

(1) Acreage relating to properties which were not transferred to us on the original date of acquisition because consents to transfer had not been obtained at that time is included in this table. The information to separate acreage on these properties is not available without undue time and expense as of the date of this report.

(2) We will not develop our acreage in Kansas and Missouri and we will let the relevant leases expire in accordance with their terms. No cost was allocated to these leases in the acquisition of the oil and natural gas properties from Calpine.

(3) Offshore productive wells are based on intervals rather than well bores.

The following table shows our interest in undeveloped acreage as of December 31, 2005 which is subject to expiration in 2006, 2007, 2008, and thereafter.

2006		2007		2008		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
37,935	33,279	77,214	73,032	25,369	20,351	166,411	132,664

Drilling Activity

The following table sets forth the number of gross exploratory and gross development wells drilled in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production. At December 31, 2005, we were in the process of drilling ten gross wells (6.0 net).

	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2005	7.0	5.0	12.0	41.0	3.0	44.0

2004	8.0	2.0	10.0	40.0	2.0	42.0
2003	17.0	8.0	25.0	20.0	5.0	25.0

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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.

	Exploratory			Development		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
2005	3.4	3.4	6.8	23.5	3.0	26.5
2004	4.3	1.0	5.3	21.1	2.0	23.1
2003	14.0	4.5	18.5	18.5	3.4	21.9

Marketing and Customers

Pursuant to our natural gas purchase and sales contract with Calpine and its existing subsidiaries, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 through December 2009 based on market prices. As of December 31, 2005, this production comprised approximately 42% of our current overall daily equivalent production. Under the terms of our gas purchase and sale contract and spot agreements with Calpine, cash payment for all natural gas volumes that are contractually sold to Calpine on the previous day are deposited into our collateral bank account. If the funds are not deposited one business day in arrears in accordance with our contract, we are not obligated to continue to sell our production to Calpine and these sales can then cease immediately. We would then be in a position to market this natural gas production to other parties. Calpine has 60 days to pay amounts owed to us, at which time we are obligated under the contract to resume natural gas sales to Calpine. We believe that Calpine s recent bankruptcy will have no significant effect on our ability to sell our natural gas at market prices. Additionally, while we may market our natural gas production, which is not subject to the above mentioned natural gas contract, to parties other than Calpine, an affiliate of Calpine will provide us administrative services in connection with such marketing efforts.

All of our other production is sold to various purchasers, including Calpine, on a competitive basis.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant 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 government of the United States; however, 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 laws and regulations may, however, substantially increase the costs of exploring for, developing or producing 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 of the Rocky Mountain region. 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.

Regulation

The oil and natural gas industry in the United States is subject to extensive regulation by federal, state and local authorities. We hold onshore and offshore federal leases involving the United States Department of Interior (the Bureau of Land Management, the Bureau of Indian Affairs and the Minerals Management Service). At the federal level, various federal rules, regulations and procedures apply, including those issued by the United States Department of Interior as noted above, and the United States Department of Transportation (U.S. Coast Guard and Office of Pipeline Safety). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Varied remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject us to the various remedies as are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with these federal, state and local rules, regulations and procedures.

Transportation and Sale of Natural Gas. The Federal Energy Regulation Commission (FERC) regulates interstate natural gas pipeline transportation rates and service conditions. Although the FERC does not regulate natural gas producers such as us, the agency s actions are intended to foster increased competition within all phases of the natural gas industry. To date, the FERC s pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the natural gas industry will have on our natural gas sales efforts.

The FERC, the United States Congress or state regulatory agencies may consider additional proposals or proceedings that might affect the natural gas industry. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other natural gas producers with which we compete.

Regulation of Production. Oil and natural gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing 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 the regulation of the spacing, and plugging and abandonment of wells. Also, each state generally imposes an ad valorem, production or severance tax with respect to production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

U.S. Minerals Management Services of the Department of the Interior. The Minerals Management Service (MMS) has broad authority to regulate our oil and natural gas operations on offshore leases in federal waters. It must approve and grant permits in connection with our drilling and development plans. Additionally, the MMS has promulgated regulations requiring offshore production facilities to meet stringent engineering and construction specifications restricting the flaring or venting of natural gas, governing the plugging and abandonment of wells and controlling the removal of production facilities. Under certain circumstances, the MMS may suspend or terminate any of our operations on federal leases, and has proposed regulations that would permit it to expel unsafe operators from offshore operations. The MMS has also established rules governing the calculation of royalties and the valuation of oil produced from federal offshore leases and regulations regarding costs for natural gas transportation. Delays in the approval of plans and issuance of permits by the MMS because of staffing, economic, environmental or other reasons could adversely affect our operations.

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Environmental Regulations. The exploration for and development of geothermal resources, oil, natural gas liquids and natural gas, and the drilling and operation of wells, fields, and gathering systems, are subject to extensive federal, state and local laws and regulations adopted for the protection of the environment and to regulate land use. The laws and regulations applicable to us primarily involve the discharge of emissions into the water and air and the use of water, but can also include wetlands preservation, endangered species, hazardous materials handling and disposal, waste disposal and noise regulations. These laws and regulations in many cases require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies.

Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. If a person violates these environmental laws and regulations and any related permits, he or she may be subject to significant administrative, civil and criminal penalties, injunctions and construction bans or delays. If we were to discharge hydrocarbons or hazardous substances into the environment, we could, to the extent the event is not insured, incur substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws also may impose clean-up or other remedial obligations in the event of a release of pollutants or contaminants into the environment.

The environmental laws and regulations, which have the most significant impact on the oil and natural gas exploration and production industry, are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an EA prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed EIS that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, affect oil and natural gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and on the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil, natural gas, or geothermal energy constitute solid wastes , which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as hazardous wastes .

We believe that we are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws.

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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 not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, not to carry loss of production or business interruption insurance for our operations.

Filings of Reserve Estimates With Other Agencies

During 2005, we filed estimates of our oil and gas reserves for the year 2004 with the Department of Energy for those properties which we operate. These estimates differ by five percent or less from the reserve data presented. For information concerning proved natural gas NGLs and crude oil reserves, see *Supplemental Oil and Gas Disclosures.*

Employees

As of December 31, 2005, we have 111 full time employees. We also contract for the services of independent consultants involved in land, regulatory accounting, financial 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.

Access to Company Reports

For further information pertaining to us, you may inspect without charge at the public reference facilities of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549 any of our filings with the SEC. Copies of all or any portion of the documents may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The web site can be accessed at *www.sec.gov*.

Corporate Governance Matters

Our website is *http://www.rosettaresources.com.* All corporate filings with the SEC can be found on our website, as well as other information related to our business. Under the Corporate Governance tab you can find copies of our Code of Business Conduct and Ethics, our Nominating and Corporate Governance Committee Charter, our Audit Committee Charter, and our Compensation Committee Charter.

Item 1A. Risk Factors.

Calpine s recent bankruptcy filing may adversely affect us in several respects.

Calpine and certain of its subsidiaries (the Debtors) filed for protection under the federal bankruptcy laws in the Southern District of New York on December 20, 2005 (the Petition Date). The Debtors may bring an action under the Bankruptcy Code or relevant state fraudulent conveyance laws asserting that Calpine s transfer of its domestic oil and natural gas business to us (as either the initial transferee or the immediate or mediate transferee from the initial transferee) should be voided or set aside as a fraudulent transfer. To prevail in such a legal action, the Debtors would be required to prove that Calpine either:

(i) transferred its domestic oil and natural gas business to us with the intent of hindering, delaying or defrauding its current or future creditors; or

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(ii) as of July 7, 2005 (the date of the closing of the acquisition), (a) received less than reasonably equivalent value for the business, and (b) was insolvent, became insolvent as a result of such transfer, was engaged in a business or transaction or was about to engage in a business or transaction for which any property remaining was unreasonably small, or intended to incur or believed it would incur debts that would be beyond its ability to pay as such debts matured.

Our primary defense against such a legal challenge rests on the extensive negotiations leading up to, and the market pricing mechanisms incorporated within the terms of the acquisition. Nonetheless, if after a trial on the merits, the court were to determine that the Debtors have met their burden of proof, it could void the transfer or take other actions against us, including (i) setting aside the acquisition and returning our purchase price and give us a first lien on all the properties and assets we purchased in the acquisition or (ii) sustaining the acquisition subject to our being required to pay the Debtors the amount, if any, by which the fair value of the business transferred, as determined by the court as of July 7, 2005, exceeded the purchase price determined and paid in July 2005. If the bankruptcy court should so rule, a setting aside of the acquisition would be materially detrimental to us in that substantially all our properties would be returned to Calpine, subject to our right (as a good faith transferee) to retain a lien in our favor to secure the return of the purchase price we paid for the properties. Additionally, if the bankruptcy court should so rule, any requirement to pay an increased purchase price could adversely affect us depending on the amount we might be required to pay.

Additionally, at the closing of the acquisition, Calpine agreed to sell but retained title to certain domestic oil and gas properties, subject to obtaining various third party consents or waivers of preferential purchase rights necessary in order to effect transfer of title. In July 2005, as part of the transactions undertaken in connection with closing the acquisition, we accepted possession of and have since been operating all of the properties for which Calpine retained record legal title. We withheld approximately $75 million from the aggregate purchase price, which was the allocated dollar amount under the PSA for the properties. Subsequent to the closing of the acquisition, with the exception of the properties subject to this preferential right, we obtained substantially all of the consents to assign for all of these properties for which consents were actually required. Prior to the Calpine bankruptcy, we were prepared to consummate the assignments of these properties, excepting those subject to the preferential purchase right. The PV-10 value of these properties at December 31, 2005 was approximately $72.4 million. Based on our internal calculations, we estimate the PV-10 value as of March 31, 2006 to be approximately $51.1 million. We are prepared to pay Calpine the retained portion of the original purchase price, approximately $68 million, upon our receipt from Calpine of record title to these properties, free of any encumbrance, and for that portion of these properties which are the cured non-consent properties, subject to appropriate adjustment for the net revenues through December 15, 2005. If the assignment of these properties does not occur, the portion of the purchase price we held back pending consent will be retained by us and will be available to us for general corporate purposes.

In addition, certain of the properties we purchased from Calpine and paid Calpine for on July 7, 2005, require certain additional documentation, depending on the particular facts and circumstances surrounding the particular properties involved, such documentation to be delivered by Calpine to quiet title related to Rosetta s ownership of these properties. Certain of these properties are subject to ministerial governmental action approving us as qualified assignee and operator, even though in most cases there had been a conveyance by Calpine and release of mortgages and liens by Calpine s creditors. For certain other properties, the documentation delivered by Calpine at closing was incomplete. While the Company remains hopeful that it will be able to work cooperatively with Calpine to secure these ministerial governmental approvals and accomplish the curative corrections for all of these properties for which the Company paid Calpine for, all of the same being covered, we believe, by the further assurances provision of the parties definitive agreements, the exact details for each property involved of how, when and if this will be able to be secured or accomplished continue to remain uncertain at this early stage of Calpine s bankruptcy.

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.

Our revenue, profitability and cash flow depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile and even relatively modest drops in prices can significantly

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affect our financial results and impede our growth. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil and gas;
- price and quantity of foreign imports;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- domestic and foreign governmental regulations;
- political conditions in or affecting other oil producing and natural gas producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- weather conditions and natural disasters;
- technological advances affecting oil and natural gas consumption;
- overall U.S. and global economic conditions; and
- price and availability of alternative fuels.

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

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

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

- lack of acceptable prospective acreage;
- inadequate capital resources;

- weather conditions and natural disasters;
- title problems;
- compliance with governmental regulations;
- mechanical difficulties; and
- availability of equipment.

Counterparty credit default could have an adverse effect on us.

Our revenues are generated under contracts with various counterparties. Results of operations would be adversely affected as a result of non-performance by any of these counterparties of their contractual obligations under the various contracts. A counterparty s default or non-performance could be caused by factors beyond our control. A default could occur as a result of circumstances relating directly to the counterparty, or due to

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circumstances caused by other market participants having a direct or indirect relationship with the counterparty. Defaults by counterparties may occur from time to time, and this could negatively impact our results of operations, financial position and cash flows. Calpine s recent bankruptcy could result in the failure of Calpine to continue purchasing natural gas from us under our natural gas purchase and sale agreements with Calpine discussed below.

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

In connection with the acquisition, we entered into a natural gas purchase and sale contract with Calpine that obligates us to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 through December 2009 based on market prices. As of December 31, 2005, this production comprised approximately 42% of our current overall production based on an equivalent basis. Calpine s recent bankruptcy could result in failure of Calpine to continue purchasing natural gas from us. Additionally, under separate monthly spot agreements, we may sell our natural gas production, not subject to the term contract to Calpine, which could increase our credit exposure to Calpine. Under the terms of our natural gas purchase and sale contract and spot agreements with Calpine, all natural gas volumes that are contractually sold to Calpine are collateralized by Calpine making daily margin payments to our collateral account equal to the previous day s natural gas sales. In the event of a default by Calpine, we could be exposed to the loss of up to four days of natural gas sales revenue under the contract, which at prices and volumes in effect as of December 31, 2005 would be approximately $1.4 million.

Unless we replace our oil and natural gas reserves, our reserves and production will decline.

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

Future projects and acquisitions may depend on our ability to obtain financing beyond our cash flow from operations. We will finance our business plan and operations primarily with internally generated cash flow, bank borrowings, entering into exploratory arrangements with other parties and privately raised equity. 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 restrictive and financial covenants that limit our ability to pay dividends. 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, change our lines of business and pay dividends on our common stock. We will also be required by the terms of our credit facilities to comply with financial covenant ratios. A more detailed description of our credit facilities is included in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and the footnotes to the consolidated/combined financial statements.

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

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

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

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

Our exploration and development activities may not be commercially successful.

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

- unexpected drilling conditions; pressure or irregularities in formations; equipment failures or accidents;
- adverse weather conditions, including hurricanes, which are common in the Gulf of Mexico during certain times of the year; compliance with governmental regulations; unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and natural gas prices; and
- limitations in the market for oil and natural gas.

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

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 independent petroleum engineers and geologists. There are numerous uncertainties inherent in

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estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. 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 and expenditures for future development and exploration activities, and of 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. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The present value of future net revenues from our proved reserves referred to in this Report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming royalties to the Minerals Management Service (MMS), royalty owners and other state and federal regulatory agencies with respect to our affected properties, will be paid or suspended for the life of the properties based upon oil and natural gas prices as of the date of the estimate. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

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

We are subject to complex government regulation that could adversely affect our operations.

Our activities are subject to complex and stringent environmental and other governmental laws and regulations. The exploration and production of oil and natural gas requires numerous permits, approvals and certificates from appropriate federal, state and local governmental agencies, including state and local agencies in California, whose regulations typically are more stringent than in other states or localities, as well as compliance with environmental protection legislation and other regulations. We remain subject to a varied and complex body of laws and regulations that both public officials and private individuals may seek to enforce. Existing laws and regulations are routinely revised or reinterpreted, and new laws and regulations may become applicable to us that could have a negative effect on our business and results of operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain and maintain permits. If a project is unable to function as planned due to changing requirements or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project.

Our business is subject to federal, state and local laws and regulations as interpreted by governmental agencies and other bodies, including those in California, vested with much authority relating to the exploration for, and the development, production and transportation of, oil and natural gas, as well as environmental and safety matters. Existing laws and regulations are routinely changed, and any changes could increase costs of compliance and costs of operating drilling equipment or significantly limit drilling activity.

Under certain circumstances, the MMS may require that our operations on federal leases be suspended or terminated. These circumstances include our failure to pay royalties or our failure to comply with safety and environmental regulations. The requirements imposed by these laws and regulations are frequently changed and

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subject to new interpretations, and if such were to occur, could negatively impact our results of operations and cash flows.

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

Our success is largely dependent on the skills, experience and efforts of our employees. The loss of the services of one or more members of our senior management or of numerous employees with critical skills could have a negative effect on our business, financial conditions and results of operations and future growth.

Our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

Our quarterly operating results have fluctuated in the past and could be negatively impacted in the future as a result of a number of factors, including:

- seasonal variations in oil and natural gas prices;
- variations in levels of production; and
- the completion of exploration and production projects.

The ultimate outcome of the legal proceedings relating to our activities cannot be predicted. Any adverse determination could have a material adverse effect on our financial condition, results of operations or cash flows.

Operation of our properties has generated various litigation matters arising out of the normal course of business. In connection with the transfer and assumption agreement with Calpine, we generally assumed liabilities arising from our activities from and after July 7, 2005 for and defense of future litigation and claims involving Calpine s domestic oil and natural gas reserves that we acquired in the acquisition, other than certain litigation that Calpine and its subsidiaries retained by agreement. Calpine s recent bankruptcy may affect these retained claims. The ultimate outcome of claims and litigation relating to our activities cannot presently be determined, nor can the liability that may potentially result from a negative outcome be reasonably estimated presently for every case. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result, these matters may potentially be material to our financial condition, results of operations or cash flows.

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

Market conditions, the unavailability of satisfactory oil and natural gas processing and transportation or the remote location of certain of our drilling operations may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. In deepwater operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. 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 pipeline or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

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

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Many of our competitors, major and

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

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;
- earthquakes and hurricanes;
- pollution; and
- releases of toxic gas.

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

In addition, our operations in California are especially susceptible to damage from natural disasters such as earthquakes and fires and involve increased risks of personal injury, property damage and marketing interruptions. Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition, or could result in a loss of our properties. Our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. For example, we are not fully insured against earthquake risk in California because of high premium costs. Insurance covering earthquakes or other risks may not be available at premium levels that justify its purchase in the future, if at all. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the d