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

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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 damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

Environmental liabilities could adversely affect our financial condition.

The oil and natural gas business is subject to environmental hazards, such as oil spills, natural gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties we have

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purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

- well drilling or workover, operation and abandonment;
- waste management;
- land reclamation;
- financial assurance under the Oil Pollution Act of 1990; and
- controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production, and may affect our costs of acquisitions. We are unable to predict the ultimate cost of complying with these regulations.

In addition, environmental laws may, in the future, cause a decrease in our production or cause an increase in our costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

Some of our California properties have been in operation for a substantial length of time, and current or future local, state and federal environmental and other laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with these laws and regulations. A variety of existing laws, rules and guidelines govern activities that can be conducted on our properties and other existing or future laws, rules and guidelines could prohibit or limit our operations and our planned activities for properties.

Under our Purchase and Sale Agreement with Calpine, we are responsible for environmental claims prior to the acquisition and we have no indemnification from Calpine related to those claims.

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

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

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

- diversion of management s attention;
- the need to integrate acquired operations;
- potential loss of key employees of the acquired companies;

- potential lack of operating experience in a geographic market of the acquired business; and
- an increase in our expenses and working capital requirements.

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

We are vulnerable to risks associated with operating in the Gulf of Mexico.

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

- adverse weather conditions and natural disasters;

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- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- remediation and other costs resulting from oil spills or releases of hazardous materials; and
- failure of equipment or facilities.

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

Hedging transactions may limit our potential gains.

We entered into natural gas price hedging arrangements with respect to a significant portion of our expected production through 2009. Such transactions may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement, or the counterparties to our hedging agreements fail to perform under the contracts.

The historical financial results of the domestic oil and natural gas business of Calpine may not be representative of our results as a separate company.

The combined historical financial information included in this report does not necessarily reflect what our financial position, results of operations and cash flows would have been had we been a separate, stand-alone entity during the periods presented. The costs and expenses reflect charges from Calpine for centralized corporate services and infrastructure costs. The allocations were determined based on Calpine s methodologies. This combined historical financial information is not necessarily indicative of what our results of operations, financial position and cash flows will be in the future.

Failure to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business.

Under current rules of the SEC, as of December 31, 2007, we will be required to document and test our internal control over financial reporting so that our management can certify as to the effectiveness of our internal control over financial reporting and our independent registered public accounting firm can render an opinion on management s assessment. We cannot be certain as to the timing of completion of our evaluation, testing and remediation actions, if any, or the impact of the same on our operations. The assessment of our internal control over financial reporting will require us to expend significant management and employee time and resources and incur significant additional expense.

We have begun the process of evaluating and documenting our internal control over financial reporting in order to test and determine any remediation actions that may be necessary and to fully implement the requirements relating to internal controls and all other aspects of related SEC rules and the Sarbanes Oxley Act of 2002. Management has begun the process of developing a stand-alone infrastructure and has determined that certain general computer controls, specifically system security and change control procedures associated with the Excalibur accounting system of the oil and natural gas businesses we acquired from Calpine, need to be upgraded for our use. Additionally, management has identified the following material weaknesses as of December 31, 2005: (1) lack of a sufficient complement of permanent personnel to have an appropriate accounting and financial reporting structure to support the activities of the Company and (2) ineffective controls as related to the identification and documentation of accounting policies, including selection and application of generally accepted accounting principles used for accounting for select transactions and other activities. See Item 9A. Controls and Procedures, for a further discussion on these material weaknesses.

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We have begun a process of remediating the recognized areas of internal controls that need improvement and have launched corrective actions to meet the required SEC and Sarbanes-Oxley standards. Our efforts may not be successful and additional deficiencies or weaknesses in our internal controls and procedures may be identified.

Our prior and continuing relationship with Calpine exposes us to risks attributable to Calpine s businesses and credit worthiness.

We acquired a business that previously was integrated within Calpine and is subject to liabilities and risk for activities of businesses of Calpine other than the acquired business. In connection with our separation from Calpine, Calpine and certain of its subsidiaries have agreed to retain certain liabilities. Third parties may seek to hold us responsible for some or all of those retained liabilities. Under our purchase and sale agreement, Calpine and certain of its subsidiaries have agreed to indemnify us for these retained liabilities.

Any claims made against us that are properly attributable to Calpine and certain of its subsidiaries will require us to exercise our rights under the indemnification provisions of the purchase and sale agreement to obtain payment from Calpine and certain of its subsidiaries, as the case may be. We are exposed to the risk that, in these circumstances and in light of the Calpine bankruptcy, any or all of Calpine and certain of its subsidiaries cannot or will not make the required payment. If this were to occur, our business and results of operations, financial position or cash flow could be adversely affected.

If we are unable to obtain governmental approvals arising from the acquisition, we may not acquire all of Calpine s domestic oil and gas business.

The consummation of the acquisition required various approvals, filings and recordings with governmental entities to transfer existing contracts and arrangements as well as all of Calpine s domestic oil and gas properties to us. In addition, all government issued permits and licenses that are important to our business, including permits issued by the City of Rio Vista and Counties of Sacramento, Solano and Contra Costa, California, may require reapplication or application by us and reissuance or issuance in our name. If we are unable to obtain a reissuance or issuance of any contract, license or permit being transferred, we have entered into a transition services agreement with Calpine pursuant to which, to the extent possible, we will receive the benefits of the contract, license or permit and will discharge the duties and bear the costs and risks under such contract, license or permit.

The ongoing SEC informal inquiry relating to the downward revision of the estimate of continuing proved reserves, while owned by Calpine, could have a material adverse effect on the presentation of our predecessor financial statements.

In April 2005, the staff of the Division of Enforcement of the SEC commenced an informal inquiry into the facts and circumstances relating to the downward revision of the estimate of continuing proved natural gas reserves at December 31, 2004, while the domestic oil and natural gas properties were owned by Calpine. Calpine has advised us that it is fully cooperating with this informal inquiry which also involved two other non-oil and natural gas related matters, and we have separately agreed with Calpine that we will also fully cooperate. Calpine has advised us that it has not had any further response or inquiry from the SEC staff in regard to this matter since July 2005 and that the ultimate outcome of this inquiry cannot presently be determined. However, it is possible that the staff of the SEC could conclude that the estimate of continuing proved reserves as of December 31, 2004, as revised, requires further downward revision, which could have a material adverse effect on the presentation of our predecessor financial statements.

Future sales of our common stock may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline, which could impair our ability to raise capital through the sale of additional common or preferred stock.

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Stock sales and purchases by institutional investors or stockholders with significant holdings could have significant influence over our stock volatility and our corresponding ability to raise capital through debt or equity offerings.

Because institutional investors have the ability to trade in large volumes of shares of our common stock, the price of our common stock could be subject to significant volatility, which could adversely affect the market price for our common stock as well as limit our ability to raise capital or issue additional equity in the future.

You may experience dilution of your ownership interests because of the future issuance of additional shares of our common and preferred stock.

We may in the future issue our previously authorized and unissued equity securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. We are currently authorized to issue an aggregate of 155,000,000 shares of capital stock consisting of 150,000,000 shares of common stock and 5,000,000 shares of preferred stock with preferences and rights as determined by our Board of Directors. As of December 31, 2005, 50,585,400 shares of common stock were issued, including 278,000 shares of restricted stock issued to certain employees and directors that vested in 2005 or early in 2006 and 307,400 shares of restricted stock that vest over a three-year period ending in 2008. Pursuant to our 2005 Long-Term Incentive Plan, we have reserved 3,000,000 shares of our common stock for issuance as restricted stock, stock options and/or other equity based grants to employees and directors. Of the reserved shares, 1,233,333 may be awarded as restricted stock and 1,766,667 may be awarded as stock options and/or other equity based grants and includes 706,550 options to purchase common stock issued to certain employees and directors. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future issuance of our securities for capital raising purposes, or for other business purposes.

Provisions under Delaware law, our certificate of incorporation and bylaws could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions under Delaware law, our certificate of incorporation and bylaws could delay or prevent a change in control of the Company, which could adversely affect the price of our common stock. Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. Our certificate of incorporation and bylaws prohibit our stockholders from taking action by written consent absent approval by all members of our Board of Directors. Further, our stockholders do not have the power to call a special meeting of stockholders.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is included in Item 1. Business and is incorporated herein by reference.

Our headquarters are located at 717 Texas, Suite 2800, Houston, Texas 77002, where we sublease two floors of office space from Calpine. We also maintain a division office in Denver, Colorado, where we lease office space from a third party. At acquisition, we were assigned this lease by Calpine who then subleased some office space from us. Calpine subsequently rejected the contract and we now lease our office space directly from a third party. We also have field offices in Laredo, Texas and Rio Vista, California. All leases were negotiated at market prices applicable to their respective location.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens

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on at least 80% of our proved reserves in accordance with our credit facilities. We do not believe that any of these burdens materially interferes with our use of the properties in the operation of our business.

Except as noted in the Transfers Pending at Calpine s Bankruptcy section on pages 4 and 5, we believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Calpine s recent bankruptcy may delay or frustrate our ability to complete additional transfers of properties for which consents were not obtained as of July 7, 2005.

Item 3. Legal Proceedings.

Legal Proceedings

We are involved in various other claims and legal actions arising out of the normal course of our business. We do not anticipate that the outcome of these claims and legal actions will have a material adverse effect on our financial position, results of operations or cash flows.

Calpine Bankruptcy

We have engaged bankruptcy counsel to monitor the Calpine bankruptcy proceeding and advocate our interests as necessary. As of the date of this report, we have not been named as a party to any proceeding or have received any notice to appear with respect to this bankruptcy proceeding. The only significant event affecting us directly has been the approval of the bankruptcy court for Calpine, as debtor-in-possession, to continue payments to us for our delivery of natural gas under our gas purchase and sale agreement.

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

No matters were submitted to a vote of our security holders during the fourth quarter of 2005.

Executive Officers of the Registrant.

B. A. Berilgen, has served as Chairman of the Board, President and Chief Executive Officer of Rosetta Resources Inc. since its formation in June 2005. Prior to joining Rosetta, Mr. Berilgen served as Executive Vice President of Calpine Corporation and as President Calpine Power Fuels Company from January 2003 to June 2005. Previously he served as Senior Vice President Natural Gas of Calpine Corporation from October 1999 to January 2003. Additionally, since October 1999, Mr. Berilgen served as Executive Vice President of Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.), then a subsidiary of Calpine and the operator of Calpine s domestic oil and natural gas business. On December 20, 2005, Calpine Corporation and certain subsidiaries filed for bankruptcy protection in the Southern District of New York. Mr. Berilgen was President and Chief Executive Officer of Sheridan Energy, a publicly traded oil and gas company from 1997 to 1999, when Sheridan was acquired by Calpine. Mr. Berilgen previously worked as Vice President of Operations for Forest Oil and has also held positions with Aminoil, ANR Production Company and Mobil during his 35-year career in exploration and production. He holds a Bachelors degree in Petroleum Engineering and a Masters degree in Industrial Engineering, both from the University of Oklahoma.

Michael J. Rosinski, has served as Executive Vice President, Chief Financial Officer, and Treasurer of Rosetta Resources Inc. since July 2005. Prior to joining Rosetta, Mr. Rosinski served as Executive Vice President

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and Chief Financial Officer of Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.). Prior to that Mr. Rosinski served as Chief Financial Officer of Power3 Medical Products from July 2004 through May 2005, and was Senior Vice President and Chief Operating Officer of Municipal Energy Resources Corporation from 1997 to 2004. Previously, he held positions as Senior Vice President and Chief Financial Officer of Santa Fe Energy, and held a number of positions at Tenneco. Mr. Rosinski holds a Masters degree in Business Administration from Tulane University and a Bachelors degree in Mechanical Engineering from Georgia Tech. He has over 35 years of experience in energy financing, financial management and controls, planning and investor relations in energy and related industries.

Charles F. Chambers, has served as Executive Vice President, Corporate Development of Rosetta Resources Inc. since June 2005. Prior to joining Rosetta and since February 2005, Mr. Chambers served as Vice President of Business Development and Land for Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.). Prior to that in March 2002, he founded Buena Vista Oil & Gas for the purpose of acquiring domestic oil and gas assets, and he served as its President. Mr. Chambers served as Vice President, Business Development for Rosetta Resources Operating LP from October 1999 until March 2002. Mr. Chambers served as Vice President, Corporate Development of Sheridan Energy from 1997 until 1999 when Sheridan was acquired by Calpine. Prior to these assignments, Mr. Chambers was land manager at C&K Petroleum Inc. and later founded Chambers Oil & Gas, Inc., an independent operator active in the Texas-Louisiana Gulf Coast. Mr. Chambers has 32 years of experience in the oil and gas industry.

Michael H. Hickey, has served as Vice President and General Counsel of Rosetta Resources Inc. since August 2005. Mr. Hickey has previous experience in the role as general counsel having served as Vice President Law and Secretary of Technip Offshore Inc., from April 2004 through July 2005. He is knowledgeable concerning Rosetta s oil and natural gas business, having been promoted to Vice President and Managing Counsel for Calpine s North American E&P and midstream group, where he contributed to the growth of these oil and natural gas assets from September 2000 to March 2004. He served as Vice President, General Counsel and Secretary of Kosa B.V. from December 1998 until August 2000. He holds a Bachelors of Arts degree and J.D. both from the University of Tennessee and has been a practicing lawyer for 26 years.

Edward E. Seeman, has served as Vice President, Northern Division of Rosetta Resources Inc. since July 2005. Prior to joining Rosetta, Mr. Seeman served as Director, Reservoir Engineering since April 2001 for Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.). Previously, he held a number of positions with Forest Oil Corporation beginning in 1974. He holds a Bachelors degree in Petroleum Engineering from the University of Oklahoma and has over 31 years of reservoir engineering experience in the oil and gas industry.

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PART II

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

Trading Market

Our common stock is listed on The NASDAQ National Market® under the symbol ROSE . Our common stock began trading on February 13, 2006, the date of the effectiveness of our registration of 50,279,000 shares which was a portion of our common stock for resale by our stockholders to the public on a delayed or continuous basis. We do not receive any proceeds from the sales of any of these shares of common stock. Prior to such date, there was no public market for our common stock. However, certain qualified institutional investors participated in limited trading through quotes on The PORTAL Market after July 7, 2005 and through December 31, 2005. The reported last sale price per share of our common stock as quoted through The NASDAQ National Market® on April 10, 2006 was $18.55 per share. As of such date we had 50,587,269 shares outstanding, 362,400 of which are subject to vesting over a three-year period from date of issuance.

The number of shareholders of record on April 10, 2006, was 112. However, we estimate that we have a significantly greater number of beneficial shareholders because a substantial number of our common shares are held of record by brokers or dealers for the benefit of their customers.

We have not paid a cash dividend on our common stock and currently intend to retain earnings to fund the growth and development of our business. Any future change in our policy will be made at the discretion of our board of directors in light of the financial condition, capital requirements, earnings prospects of Rosetta and any limitations imposed by lenders or investors, as well as other factors the board of directors may deem relevant.

We did not repurchase any of our securities during the fourth quarter of the year ended December 31, 2005.

Issuance and Sale of Capital Stock

During the year ended December 31, 2005, we sold the following securities that were not registered under the Securities Act of 1933, as amended:

Date of Sale	Title and Amount of Securities Sold		Name or Class of Purchaser of Securities	Consideration
July 7, 2005	45,312,500	Common Stock	Qualified Institutional Buyers and Offshore Parties	$725 Million
July 13, 2005	4,687,500	Common Stock	Qualified Institutional Buyers and Accredited Investors	$75 Million

Friedman, Billings & Ramsey Co, Inc. acted as underwriter and as placement agent in the foregoing sales of securities. For its role as underwriter and placement agent, FBR received a discount equal to seven percent (7%) of the aggregate consideration. All such sales were made in reliance upon an exemption from the registration provisions of the Securities Act set forth in Section 4(2) thereof relating to sales by an issuer not involving any public offering or the rules and regulations thereunder, under Rule 144A as promulgated under the Securities Act relating to resales to qualified institutional buyers, and under Regulation S as promulgated under the Securities Act relating to offshore transactions.

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Additionally, during the year ended December 31, 2005, we issued the following securities that were not registered under the Securities Act of 1933, as amended:

Date of Issuance	Title and Amount of Securities Issued		Name or Class of Purchaser of Securities	Consideration	
July 7, 2005	231,400	Common Stock	Officers and Other employees	$	-0-
July 8, 2005	253,500	Common Stock	Employees	$	-0-
July 13, 2005	5,000	Common Stock	Employees	$	-0-
July 15, 2005	1,000	Common Stock	Employees	$	-0-
July 25, 2005	1,000	Common Stock	Employees	$	-0-
August 1, 2005	21,500	Common Stock	Directors and Employees	$	-0-
August 3, 2005	5,000	Common Stock	Employees	$	-0-
August 15, 2005	12,500	Common Stock	Employees	$	-0-
August 22, 2005	500	Common Stock	Employees	$	-0-
September 1, 2005	2,500	Common Stock	Employees	$	-0-
September 6, 2005	12,500	Common Stock	Employees	$	-0-
September 14, 2005	5,000	Common Stock	Employees	$	-0-
September 19, 2005	500	Common Stock	Employees	$	-0-
September 28, 2005	8,500	Common Stock	Employees	$	-0-
October 21, 2005	2,000	Common Stock	Employees	$	-0-
October 31, 2005	10,000	Common Stock	Employees	$	-0-
November 1, 2005	7,000	Common Stock	Employees	$	-0-
November 14, 2005	6,000	Common Stock	Employees	$	-0-
November 21, 2005	2,000	Common Stock	Employees	$	-0-
December 1, 2005	4,500	Common Stock	Consultants and Employees	$	-0-
December 6, 2005	1,000	Common Stock	Employees	$	-0-
December 12, 2005	1,000	Common Stock	Employees	$	-0-

No underwriters were used in the foregoing issuances of securities. All such issuances were made in reliance upon an exemption from the registration provisions of the Securities Act set forth in Rule 701 as promulgated under the Securities Act relating to issuances of securities under compensatory plans.

Grants of Stock Options

Additionally, we have granted to our employees, including executive officers, options to purchase 706,550 shares of our common stock at exercise prices ranging from $16 per share to $19 per share. All such issuances were made in reliance on Rule 701 as promulgated under the Securities Act relating to issuances of securities under compensatory plans.

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Item 6. Selected Financial Data.

The following historical financial data, as of December 31, 2004, and for the fiscal years ended December 31, 2003 and 2004, and for the six months ended June 30, 2005, has been derived from the combined financial statements of the domestic oil and natural gas properties of Calpine (predecessor) appearing elsewhere, herein. The historical financial data as of December 31, 2003, and for the year ended December 31, 2002, has been derived from the combined financial statements of the domestic oil and natural gas properties of Calpine (predecessor) not appearing herein. The historical financial data as of December 31, 2001 and 2002, and for the year ended December 31, 2001, has been derived from the books and records of the domestic oil and natural gas properties of Calpine (predecessor). The historical financial data as of December 31, 2005 and for the six months ended December 31, 2005 (successor) has been derived from the consolidated financial statements of Rosetta Resources Inc. appearing herein. You should read the following selected historical consolidated/combined financial data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operation and the audited consolidated/combined financial statements and related notes included elsewhere in this report. The predecessor historical financial data was derived from financial data of Calpine when we were not a stand-alone business. Additionally, the historical financial data reflects successful efforts accounting for oil and natural gas properties for the predecessor periods described above and the full cost method of accounting for oil and natural gas properties effective July 1, 2005 for the six months ended December 31, 2005, the successor period, described below and herein this report. In addition, the Company adopted the intrinsic value method of accounting for stock options as outlined in Accounting Practice Bulletin No. 25, Stock Issued to Employees , effective July 1, 2005. See Management s Discussion and Analysis of Financial Condition and Results of Operations. The selected historical results are not necessarily indicative of results to be expected in future periods.

	Predecessor					Successor
	For the Years Ended December 31,				For the Six Months Ended June 30,	For the Six Months Ended December 31,
	2001	2002	2003	2004	2005	2005
	(In thousands)					
Operating Results Data						
Total revenue	$ 190,665	$ 157,372	$ 279,916	$ 248,006	$ 103,831	$ 113,104
Costs and expenses:						
Depreciation, depletion and amortization	52,590	64,109	72,766	81,590	30,679	40,500
Impairment		6,034	2,931	202,120		
Other costs and expenses	41,974	57,971	74,391	67,359	36,289	37,001
Total costs and expenses	94,564	128,114	150,088	351,069	66,968	77,501
Operating income (loss)	96,101	29,258	129,828	(103,063)	36,863	35,603
Other income (expense)	10,855	(26,821)	(18,441)	(24,298)	(6,686)	(6,531)
Income (loss) before provision for income taxes, discontinued operations and cumulative effect of change in accounting principle, net of taxes	106,956	2,437	111,387	(127,361)	30,177	29,072
Provision (benefit) for income taxes	42,055	953	44,508	(48,525)	11,496	11,537
Income (loss) before discontinued operations and cumulative effect of change in accounting principle, net of taxes	64,901	1,484	66,879	(78,836)	18,681	17,535
Discontinued operations, net of taxes	2,183	(1,652)	4,405	68,440		
Cumulative effect of change in accounting principle, net of taxes			156			
Net income (loss)	$ 67,084	$ (168)	$ 71,440	$ (10,396)	$ 18,681	$ 17,535

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SELECTED HISTORICAL CONSOLIDATED/COMBINED FINANCIAL DATA (continued):

	Predecessor					Successor
	For the Years Ended December 31,				For the Six Months Ended June 30,	For the Six Months Ended December 31,
	2001	2002	2003	2004	2005	2005
	(In thousands, except per share data)					
Earnings per share:						
Basic						
Income (loss) before discontinued operations and cumulative effect of change in accounting principle, net of taxes	$ 1.30	$ 0.03	$ 1.34	$ (1.58)	$ 0.37	$ 0.35
Discontinued operations	$ 0.04	$ (0.03)	$ 0.09	$ 1.37	$	$
Cumulative effect of change in accounting principle	$	$	$	$	$	$
Net income (loss)	$ 1.34	$ (0.00)	$ 1.43	$ (0.21)	$ 0.37	$ 0.35
Diluted						
Income (loss) before discontinued operations and cumulative effect of change in accounting principle, net of taxes	$ 1.30	$ 0.03	$ 1.33	$ (1.58)	$ 0.37	$ 0.35
Discontinued operations	$ 0.04	$ (0.03)	$ 0.09	$ 1.37	$	$
Cumulative effect of change in accounting principle	$	$	$	$	$	$
Net income (loss)	$ 1.34	$ (0.00)	$ 1.42	$ (0.21)	$ 0.37	$ 0.35
Weighed average shares outstanding:						
Basic	50,000	50,000	50,000	50,000	50,000	50,003
Diluted	50,160	50,000	50,160	50,000	50,160	50,189
Balance Sheet Data						
Property and equipment, net(4)	$ 830,092	$ 822,271	$ 830,390	$ 606,520	$	$ 935,936
Assets of discontinued operations	$ 99,160	$ 96,990	$ 111,254	$	$	$
Total assets	$ 975,199	$ 940,619	$ 990,893	$ 656,528	$	$ 1,119,269
Long-term debt, less current maturities	$	$ 684	$ 507	$	$	$ 240,000
Owner s Net Investment/Stockholders Equity	$ 162,575	$ 162,407	$ 233,847	$ 223,451	$	$ 715,423
Net cash provided by (used in) continuing operations:						
Operating activities	$ 185,935	$ 50,303	$ 152,407	$ 121,182	$ 59,379	$ 63,744
Investing activities	$ (666,795)	$ (61,398)	$ (62,132)	$ (53,933)	$ (30,645)	$ (943,246)
Financing activities	$ 472,208	$ (5,145)	$ (71,498)	$ (71,646)	$ (27,239)	$ 979,226
Other Financial Data (Unaudited)						
Working capital (deficit)(1)	$ (550,591)	$ (537,828)	$ (466,039)	$ (240,508)	$	$ 65,423
Purchases of property and equipment(5)	$ 684,537	$ 79,213	$ 102,700	$ 68,386	$ 32,202	$ 942,300

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SELECTED HISTORICAL CONSOLIDATED/COMBINED FINANCIAL DATA (continued):

	Predecessor					Successor
	For the Years Ended December 31,				For the Six Months Ended June 30,	For the Six Months Ended December 31,
	2001	2002	2003	2004	2005	2005
	(In thousands, except per share amounts)					
Reconciliation of Non-GAAP Financial Data(3)						
EBITDA from continuing operations calculation is as follows:						
Net income (loss)	$ 67,084	$ (168)	$ 71,440	$ (10,396)	$ 18,681	$ 17,535
Cumulative effect of change in accounting principle, net of taxes			(156)			
Income from discontinued operations, net of tax(2)	(2,183)	1,652	(4,405)	(68,440)		
Income (loss) from continuing operations	64,901	1,484	66,879	(78,836)	18,681	17,535
Interest (income) expense with affiliates, net	(2,025)	23,312	19,050	28,034	6,995	
Interest expense, net						8,216
Other interest (income) expense, net		394	(62)	(726)	(516)	(1,837)
Income tax provision (benefit)	42,055	953	44,508	(48,525)	11,496	11,537
Income (loss) before interest and taxes	104,931	26,143	130,375	(100,053)	36,656	35,451
Other (income) expense, net	(8,830)	3,115	(547)	(3,010)	207	152
Operating income	96,101	29,258	129,828	(103,063)	36,863	35,603
Depreciation, depletion and amortization	52,590	64,109	72,766	81,590	30,679	40,500
EBITDA from continuing operations	$ 148,691	$ 93,367	$ 202,594	$ (21,473)	$ 67,542	$ 76,103

(1) Working capital deficit includes $127 million, $444 million, $528 million and $492 million of notes payable to affiliates for the years ended December 31, 2004, 2003, 2002 and 2001 (predecessor), respectively.

(2) Represents the sale of the San Juan Basin New Mexico assets and the Piceance Basin Colorado assets in 2004.

(3) EBITDA from continuing operations is calculated as net income or loss excluding income taxes, cumulative effect of change in accounting principle, net interest expense, other income, depreciation, depletion and amortization, and income from discontinued operations. It does include an impairment charge of $202.1 million, $2.9 million and $6.0 million for the years ended December 31, 2004, 2003 and 2002 (predecessor) respectively. We believe that EBITDA from continuing operations is a financial indicator commonly used by analysts and is used by them as a basis for evaluating us with our peers. We use EBITDA from continuing operations as a performance measure such as a multiple for valuation purposes of our company and the oil and gas industry as a whole. EBITDA from continuing operations should not be considered in isolation or as a substitute for net income, operating income, and net cash provided by operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

(4) For the six months ended December 31, 2005 (successor), purchases of property and equipment include $910 million related to the acquisition of the oil and gas business of Calpine.

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

Overview

Rosetta Resources Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of natural gas and oil properties in the United States. We were formed as a Delaware corporation in June 2005. In July 2005, we acquired the oil and natural gas business of Calpine Corporation and affiliates. Our operations are concentrated in the Sacramento Basin of California, Lobo and Perdido trends in South Texas, and the U.S. Gulf of Mexico (both state and federal waters). In this section, we refer to Rosetta as successor and to the domestic oil and natural gas properties acquired from Calpine as predecessor .

In accounting for the oil and natural gas exploration and production business, the predecessor used the successful efforts method of accounting for oil and natural gas activities. However, in connection with our separation from Calpine, we have adopted the full cost method of accounting for our oil and natural gas properties, (see Critical Accounting Policies and Estimates Successful Efforts Method of Accounting vs. Full Cost Method of Accounting below for further discussion of the differential effects on the combined financial statements of the two accounting methods).

Higher oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of those goods and services. Given the inherent volatility of oil and natural gas prices that are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in fair market value of hedges we executed to mitigate the volatility in the changes of oil and natural gas prices in future periods when such positions are settled as these instruments meet the criteria to be accounted for as cash flow hedges. Until settlement, the changes in fair market value of our hedges will be included as a component of stockholder s equity to the extent effective. In periods of rising prices, these transactions will mitigate future earnings and in periods of declining prices will increase future earnings in the respective period the positions are settled.

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce our reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. The permitting and approval process has been more difficult in recent years than in the past due to increased activism from environmental and other groups and has extended the time it takes us to receive permits. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we are less able to shift drilling activities to areas where permitting may be easier and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

Financial Highlights

The consolidated financial statements reflect total revenue of $113.1 million on total volumes of 13.5 Bcfe for the six months ended December 31, 2005 (successor). Operating income was $35.6 million or 31.5% of total revenue and included additional workover costs of approximately $2.0 million for our High Island A-442 and

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East Cameron 88 wells and $4.2 million of compensation expense for stock granted to employees. Additionally, operating income was affected by a decline in volumes and revenues resulting from Hurricanes Katrina and Rita and does not include volumes and revenues related to oil and natural gas properties not conveyed by Calpine in our acquisition, because consents had not been obtained at that time. Total net other expense (income) was interest expense on our credit facility offset by interest income on short term cash investments and interest capitalized to the full cost pool. Overall, our net income for the six months ended December 31, 2005 (successor) was $17.5 million or 15.5% of total revenue.

The combined financial statements reflect total revenue of $103.8 million on total volumes of 15.5 Bcfe for the six months ended June 30, 2005 (predecessor). Operating income was $36.9 million or 35.5% of total revenue and included work over cost and ad valorem taxes of $0.22 per Mcfe and $0.22 per Mcfe, respectively due to higher taxes in South Texas and a special reclamation tax in California as well as exploration costs of $2.4 million and dry hole expense of $2.0 million both of which are expensed as incurred based on the successful efforts method of accounting. Total net other expense was interest expense of $7.0 million on intercompany debt of $92.9 million offset by $(0.7) million of capitalized interest. Overall, net income for the six months ended June 30, 2005 (predecessor) was $18.7 million or 18% of total revenue.

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.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated/combined financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for

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making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements and those of our predecessor. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

Oil and Natural Gas Reserves. Oil and natural gas reserve estimates impact many of the accounting estimates in the financial statements as further discussed below. The process of estimating quantities of oil and natural gas proved reserves, particularly proved undeveloped and proved developed non-producing reserves, is complex, requiring significant judgment and subjective decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimates of economically recoverable oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of governmental regulations, operating and workover costs, severance taxes and development costs, all of which may vary considerably from actual results. Accordingly, our reserve estimates are developed internally and subsequently, provided to a third party engineering firm which then generates an annual year-end reserve report. In addition, the data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates. The estimate of proved natural gas and oil reserves primarily impact property, plant and equipment amounts in the balance sheets and the depreciation, depletion and amortization amounts in the consolidated/combined statement of operations, among other items.

Successful Efforts Method of Accounting vs. Full Cost Method of Accounting. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in oil and natural gas exploration, development, and production. Two methods are prescribed: the successful efforts method and the full cost method of accounting for oil and natural gas properties. We have adopted the full cost method of accounting for oil and natural gas properties. Under the full cost method, all costs incurred in exploring for, acquiring, and developing oil and natural gas reserves are capitalized to a full cost pool, whether or not the activities to which they apply are successful. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and certain costs related to general corporate overhead or similar activities.

Under the successful efforts method that was used by our predecessor, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a field basis versus the full cost pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method whereas under the full cost method, gains or losses are generally included in the full cost pool unless the entire pool is sold. Under the full cost method, unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment rather than amortized. Upon evaluation, these costs are transferred to the full cost pool and amortized. Under the successful efforts method, these costs are included in undeveloped leasehold cost or expensed depending on the nature of the expenditure. As a result, the financial statements for the six months ended December 31, 2005 will differ from companies that apply the successful efforts method and the financial statements presented herein for the six months ended June 30, 2005 and the years ended December 31, 2004 and 2003, since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our oil and natural gas properties. A five percent positive or negative revision to proved reserves throughout the Company would decease or increase the depreciation, depletion and amortization rate by approximately $0.15 per Mmcfe to $0.23 per Mmcfe. This estimated impact is based on current data at December 31, 2005 and actual events could require different adjustments to depreciation, depletion and amortization.

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Under the full cost accounting method for oil and natural gas properties, the net capitalized cost of oil and natural gas properties may not exceed a ceiling limit which is based upon the present value of estimated future net cash flows from proved reserves, inclusive of cash flow hedges, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings as a ceiling test write-down. This charge does not impact cash flow from operating activities, but would reduce stockholders equity and earnings. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. In addition, write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for our natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period.

Under the successful efforts method of accounting for oil and natural gas properties followed by our predecessor, they reviewed their oil and natural gas properties periodically (at least annually) to determine if impairment of such properties was necessary. Property impairments occurred if a field discovered lower than anticipated reserves, reservoirs produced below original estimates or if commodity prices fell below a level that significantly affected anticipated future cash flows on the property. Proved oil and natural gas property values were reviewed when circumstances suggested the need for such a review and, if required, the proved properties were written down to their estimated fair market value based on proved reserves and other market factors. Unproved properties were reviewed quarterly to determine if there was an impairment of the carrying value, with any such impairment charged to expense in that current period.

Management assesses the undeveloped acreage, leasehold, geological and geophysical (seismic) costs and related capitalized interest to determine if any expenses should be impaired, reclassified to proved properties or classified as a dry hole and recorded as expense in the statement of operations. The predecessor recorded $202.1 million and $2.9 million in impairment charges related to reduced proved reserve projections based on the year end independent engineers report for the years ended December 31, 2004 and 2003, respectively.

Derivative Transactions and Hedging Activities. We enter into derivative transactions to hedge against changes in oil and natural gas prices from time to time primarily through the use of fixed price swap agreements, costless collars, and put options. Consistent with our hedge policy, and in connection with entering into our credit facilities, we entered into a series of natural gas fixed-price swaps for a significant portion of our expected natural gas production through 2009. In December 2005, we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for approximately 10,000 MMBtu per day (see Quantitative and Qualitative Disclosure About Market Risk). These transactions are recorded in our financial statements in accordance with Statement of Financial Accounting Standard (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Although not risk free, we believe this policy will reduce our exposure to commodity price fluctuations and thereby achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with SFAS No. 133, as amended, all derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions every three months, consistent with documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges are included in other income (expense).

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Asset Retirement Obligations. Our predecessor adopted SFAS No. 143, Accounting for Asset Retirement Obligations as of January 1, 2003. SFAS No. 143 required them to record the fair market value of a liability for an asset retirement obligation (ARO), net of salvage value, in the period in which it was incurred. Upon adoption of SFAS No. 143, a liability was recorded for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset and a cumulative effect of a change in accounting principle was recorded in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost. Subsequent to adoption, liabilities were required to be accreted to their present value each period and capitalized costs were depreciated over the estimated useful life of the related assets. This periodic accretion expense is recorded as depreciation, depletion and amortization in the consolidated/combined statement of operations. Upon settlement of the liability, the obligation is settled against its recorded amount and the resulting gain or loss is recorded in the financial statements.

Income Taxes. Under SFAS No. 109, Accounting for Income Taxes, deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Income taxes have been calculated for the Company based on the appropriate tax regulations since it will file a tax return for the six months ended December 31, 2005 and as if the domestic oil and natural gas business of Calpine had filed a separate return for the six months ended June 30, 2005 and the years ended December 31, 2004 and 2003. See additional information in Note 10. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

To arrive at the income tax provision and other tax balances, significant judgment is required. In the ordinary course of business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Some of these uncertainties arise as a consequence of the treatment of capital assets, financing transactions and multi-state taxation of operations. Although we believe that our estimates are reasonable, no assurance can be given that the final tax outcome of these matters will not be different than that which is reflected in our tax provisions and accruals. Such differences could have a material impact on our income tax provision, other tax accounts and net income in the period in which such determination is made. While we have considered future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for a valuation allowance, there is no assurance that a valuation allowance might be needed in the future to provide for additional deferred tax assets that may not be realizable. Should we determine the need for a valuation allowance it could have a material adverse impact on our income tax provision and results of operations in the period in which such determination is made.

The effective income tax rates for continuing operations were 38.1%, and 40.0% in fiscal year 2004 and 2003, 38.1% for the six months ended June 30, 2005 and 39.7% for the six months ended December 31, 2005, respectively. The effective tax rate in all periods is the result of taxes on earnings in various domestic tax jurisdictions that apply a broad range of state income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate due primarily to state taxes, tax credits and other permanent differences. Future effective tax rates could be adversely affected if earnings are lower than anticipated, if unfavorable changes in tax laws and regulations occur, or if we experience future adverse determinations by taxing authorities after any related litigation.

Stock-based Compensation. On January 1, 2003, Calpine prospectively adopted, and the combined financial statements for 2003 and 2004 and the six months ended June 30, 2005 are presented, the fair market value method of accounting for stock-based employee compensation pursuant to SFAS No. 123, Accounting for Stock-Based Compensation , as amended by SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure (SFAS No. 123). Expense amounts included in the combined historical financial statements for the years ended December 31, 2004 and 2003 and the six months ended June 30, 2005 are based

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on stock based compensation granted to employees by Calpine. Stock options were granted at an option price equal to the quoted market price at the date of the grant or award.

In determining our accounting policies, we have chosen to apply the intrinsic value method pursuant to Accounting Standards Board (APB) APB No. 25, Stock Issued to Employees (APB No. 25) effective July 2005. Under APB No. 25, no compensation is recognized when the exercise price for options granted equal the fair value of the Company s common stock on the date of the grant.

New Accounting Pronouncements Not Yet Adopted

SFAS No. 123-R. In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123-R. This Statement revises SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123) and supersedes APB No. 25, and its related implementation guidance. This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the fair market value of the award on the date of grant (with limited exceptions), which must be recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). The statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options, or other equity instruments or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity s shares or other equity instruments or (b) that require or may require settlement by issuing the entity s equity shares or other equity instruments. The statement requires the accounting for any excess tax benefits to be consistent with the existing guidance under SFAS No. 123, which provides a two-transaction model summarized as follows:

- If settlement of an award creates a tax deduction that exceeds compensation cost, the additional tax benefit would be recorded as a contribution to paid-in-capital.

- If the compensation cost exceeds the actual tax deduction, the write-off of the unrealized excess tax benefits would first reduce any available paid-in capital arising from prior excess tax benefits, and any remaining amount would be charged against the tax provision in the income statement.

The statement also amends SFAS No. 95, Statement of Cash Flows, to require that excess tax benefits be reported as a financing cash inflow rather than as an operating cash inflow. However, the statement does not change the accounting guidance for share-based payment transactions with parties other than employees provided in SFAS No. 123 as originally issued and EITF Issue No. 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services . Further, this statement does not address the accounting for employee share ownership plans, which are subject to AICPA Statement of Position 93-6, Employers Accounting for Employee Stock Ownership Plans .

The statement applies to all awards granted, modified, repurchased, or cancelled after January 1, 2006, and to the unvested portion of all awards granted prior to that date. Public entities that used the fair market value method for either recognition or disclosure under SFAS No. 123 may adopt this Statement using a modified version of prospective application (modified prospective application). Under modified prospective application, compensation cost for the portion of awards for which the employee s requisite service has not been rendered that are outstanding as of January 1, 2006 must be recognized as the requisite service is rendered on or after that date. The compensation cost for that portion of awards shall be based on the original fair market value of those awards on the date of grant as calculated for recognition under SFAS No. 123. The compensation cost for those earlier awards shall be attributed to periods beginning on or after January 1, 2006 using the attribution method that was used under SFAS No. 123. Furthermore, the method of recognizing forfeitures must now be based on an estimated forfeiture rate and can no longer be based on forfeitures as they occur.

The adoption of SFAS No. 123-R is not expected to have a material impact on the Company s consolidated financial position, results of operations or cash flows.

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Accounting Changes and Error Corrections. In May 2005 the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 (SFAS 154), which changes the requirements for the accounting for and the reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed.

APB 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. When it is practicable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the balance sheet for that period rather than being reported in the statement of operations. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, SFAS 154 requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable.

SFAS 154 defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. SFAS 154 also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error.

SFAS 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS 154 carries forward without change the guidance contained APB 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. This Statement also carries forward the guidance in APB 20 requiring justification of a change in accounting principle on the basis of preferability.

SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Early adoption is permitted for accounting changes and corrections of errors made in fiscal years beginning after the date this Statement is issued. SFAS 154 does not change the transition provision of any existing accounting pronouncements, including those that are in a transition phase as of the effective date. The adoption of this statement is not expected to impact the Company s consolidated financial position or results of operations.

Exchanges of Nonmonetary Assets. In January 2005, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No 29*. This statement, which addresses the measurement of exchanges of nonmonetary assets, is effective prospectively for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of this statement did not impact the Company s consolidated financial position or results of operations.

Accounting for Certain Hybrid Financial Instruments. In February 2006*,* the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Instruments-an amendment of FASB Statements 133 and 140,* which is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after

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September 15, 2006. The statement improves financial reporting by eliminating the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. The Statement also improves financial reporting by allowing a preparer to elect fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to bifurcated, if the holder elects to account for the whole instrument on a fair value basis. The Company is currently evaluating the impact, if any, of this Statement on the financial statements.

Results of Operations

In July 2005, we acquired the oil and natural gas business of Calpine Corporation and affiliates. Due to the acquisition, the results of operations for the year ended December 31, 2005 are presented in two periods, successor comprising the six months ended December 31, 2005 and predecessor comprising the six months ended June 30, 2005. In addition, differences in accounting principles of the predecessor and successor exist, primarily related to the full cost method of accounting for oil and natural gas properties adopted by us and the successful effort method of accounting for oil and natural gas properties followed by the predecessor. In addition, the predecessor adopted on January 1, 2003, SFAS No. 123, Accounting for Stock-Based Compensation to measure the cost of employee services received in exchange for an award of equity instruments, whereas we adopted the intrinsic value method of accounting for stock options and stock awards effective July 1, 2005.

Successor

Six Months Ended December 31, 2005

	Six Months Ended December 31, 2005 (In thousands)
Total revenue	$ 113,104
Lease operating expense	15,674
Depreciation, depletion and amortization	40,500
Treating and transportation	1,286
Marketing fees	1,379
Production taxes	3,975
General and administrative costs	14,687
Interest expense, net of interest capitalized	8,216
Interest income	(1,837)
Other (income) expense, nets	152
Provision (benefit) for income taxes	11,537
Net Income	$ 17,535
Production:	
Gas (Bcf)	12.4
Oil (Mbbl)	185.6
Total Equivalents (Bcfe)	13.5
$ per unit:	
Avg. gas price per Mmcf	$ 8.23
Avg. gas price per Mmcf excluding hedging	9.57
Avg. oil price per Mbbl	59.52
Avg. revenue per Mmcfe	8.38
Avg. operating expense per Mmcfe	1.16
Avg. transportation & marketing per Mmcfe	0.20
Avg. production tax expense per Mmcfe	0.29
Avg. G&A per Mmcfe	1.09

Avg. DD&A per Mmcfe (excluding ceiling test write-downs)	$	3.00

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Total Revenue. Total revenue of $113.1 million for the six months ended December 31, 2005 consists primarily of natural gas sales comprising 90.3% of total revenue on total volumes of 13.5 Bcfe. Natural gas sales revenue was $102.1 million, including the effects of hedging, based on total gas production volumes of 12.4 Bcf. Lobo and Perdido production was 3.9 Bcf and 1.5 Bcf or 28.9% and 11.2%, respectively, or a total of 5.4 Bcf and 40.1% of total volumes. California production was 5.3 Bcf or 39.0% of total volumes at a total average price of $9.08 per Mcfe, excluding the effects of hedging. California production is down due to the delay in our drilling program pending an additional rig contracted in the first quarter of 2006 and compression issues. The effect of hedging on natural gas sales revenue was a decrease of $16.6 million related to volumes of 8.0 MMbtu for a decrease in total price to $8.23 per Mcf.

Oil revenue was $11.0 million based on oil production volumes of 185.6 MBbls. Southern region production was 21.9 MBbls, 8.5 MBbls, 8.3 MBbls, 42.0 MBbls and 93.0 MBbls from Lobo, Perdido, State Waters, Other Onshore and Gulf of Mexico or 94% of oil production for the six months ended December 31, 2005 at a total average price of $59.61 per Bbl for these fields. Overall volumes are down in the Gulf of Mexico due to Hurricanes Katrina and Rita and a workover program at High Island and East Cameron that was delayed in prior years due to capital constraints imposed by Calpine and does not include volumes and revenues related to oil and natural gas properties not conveyed by Calpine in our acquisition, because consents had not been obtained at that time. Fluctuations in product prices significantly impacted our revenue from existing properties

Lease Operating Expense. Our lease operating expense of $15.7 million is primarily due to oil and natural gas volumes which totaled 13.5 Bcfe for the six months ended December 31, 2005 or costs of $1.12 per Mcfe. The costs included workover costs on our High Island A-442 and East Cameron 88 wells in the Gulf of Mexico and the La Perla field in South Texas. The costs included workover costs, ad valorem taxes and insurance of $0.22 per Mcfe, $0.25 per Mcfe and $0.04 per Mcfe, respectively.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense was $40.5 million for the six months ended December 31, 2005. We adopted the full cost method of accounting for oil and gas properties as further discussed in our Critical Accounting Policies and Estimates above. whereby related costs are capitalized into the full cost pool. Our depletion rate for this period was an average of $3.00 per MMcfe. There were no ceiling test write-downs for the six months ended December 31, 2005.

Treating and Transportation. Treating and transportation was $1.3 million for the six months ended December 31, 2005 related to the treating and transportation related to a portion of our total natural gas production volumes of 12.4 Bcf.

Marketing Fees. Marketing fees were $1.4 million for the six months ended December 31, 2005. These fees relate to the contract rate charged by Calpine Producer Services (CPS) to market our gas. The fee payable by us under the agreement is based on net proceeds of all commodity sales for volumes covered by the agreement at a rate of 0.75%. This rate decreases as the volumes marketed increases.

Production Taxes. Production taxes as a percentage of natural gas and oil sales are approximately 3.56% for the six months ended December 31, 2005. Production taxes are primarily based on the wellhead values of production and vary across the different regions.

General and Administrative Costs. General and administrative costs of $14.7 million is net of capitalization of general and administrative costs of $3.5 million as a component of our oil and natural gas properties under the full cost method of accounting for oil and natural gas properties which we adopted July 1, 2005. General and administrative costs for this period include $4.2 million of stock compensation expense for stock granted to employees during the period and $10.9 million of salary and employee benefit costs before capitalization of any of these costs to our oil and natural gas properties.

Interest (income) expense. Interest (income) expense of $8.2 million, including amortization of deferred loan fees of $0.6 million related to interest on our senior credit facility and term loan which is described in

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Liquidity and Capital Resources and notes to the consolidated/combined financial statements for the six months ended December 31, 2005. Interest income of $1.8 million was earned on available cash invested in short term money market investments.

Other (Income) Expense. Other (income) expense of $0.2 million relates primarily to investment income from an equity interest for the six months ended December 31, 2005 of $0.2 million.

Provision for Income Taxes. The effective tax rate for the six months ended December 31, 2005 was 39.7%. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate due primarily to state taxes.

Net Income. We had total revenue of $113.1 million on total volumes of 13.5 Bcfe for the six months ended December 31, 2005. Operating income was $35.6 million or 31.5% of total revenue and included additional workover costs of approximately $2.0 million for our High Island A-442 and East Cameron 88 wells and $4.2 million of compensation expense for stock granted to employees. Additionally, operating income was affected by a decline in volumes and revenues resulting from Hurricanes Katrina and Rita and does not include volumes and revenues related to oil and natural gas properties not conveyed by Calpine in our acquisition, because consents had not been obtained at that time. Total net other expense (income) was interest expense on our credit facility offset by interest income on short term money market investments. Overall, our net income was $17.5 million or 15.5% of total revenue.

Predecessor

Six Months Ended June 30, 2005

	Six Months Ended June 30, 2005 (In thousands)
Total revenue	$ 103,831
Lease operating expense	16,629
Depreciation, depletion and amortization	30,679
Exploration expense	2,355
Dry Hole costs	1,962
Treating and transportation	1,998
Marketing fees	913
Production taxes	2,755
General and administrative costs	9,677
Interest expense with affiliates, net of interest capitalized	6,995
Interest income	(516)
Other (income) expense, net	207
Provision (benefit) for income taxes	11,496
Net Income	$ 18,681
Production:	
Gas (Bcf)	14.5
Oil (Mbbl)	164.0
Total Equivalents (Bcfe)	15.5
$ per unit:	
Avg. gas price per Mmcf	$ 6.59
Avg. oil price per Mbbl	49.86
Avg. revenue per Mmcfe	6.70
Avg. operating expense per Mmcfe	1.08
Avg. transportation & marketing per Mmcfe	0.19
Avg. production tax expense per Mmcfe	0.18

Avg. G&A per Mmcfe		0.63
Avg. DD&A per Mmcfe (excluding impairments)	$	1.98

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Total Revenue. Total revenue of $103.8 million for the six months ended June 30, 2005 consisted primarily of natural gas sales of $95.6 million or 92.1% of total revenue. Oil revenue was $8.1 million with oil production volumes of 164 MBbls primarily from the Gulf of Mexico region which produced 72.7 MBbls or 44% of oil production for the six months ended June 30, 2005 at an average price of $49.86 per Bbl. Natural gas sales revenue was $95.6 million with gas production volumes of 14.5 MMcf primarily from Sacramento Basin with 6.5 MMcf or 44.8% of total volumes and South Texas, primarily from Lobo of 3.7 MMcf and Perdido 1.8 MMcf, or 5.5 MMcf or 37.9% of total volumes at an average price of $6.59 per Mcf. Overall volumes were down due to capital constraints of our predecessor.

Lease Operating Expense. Lease operating expense of $16.6 million related directly to oil and natural gas volumes which totaled 15.5 MMcfe for the six months ended June 30, 2005 or costs of $1.08 per Mcf. The costs included workover cost, ad valorem taxes and insurance of $0.22 per Mcfe, $0.22 per Mcfe and $0.06 per Mcfe, respectively due to higher taxes in South Texas and a special reclamation tax in California.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense was $30.7 million for the six months ended June 30, 2005 under the successful efforts method of accounting for oil and natural gas properties. Our depletion rate for this period was an average of $1.97 per MMcfe.

Exploration expense. Exploration expense was $2.3 million for the six months ended June 30, 2005 under the successful efforts method of accounting for oil and natural gas properties. This expense was comprised of geological and geophysical salaries and expenses of $1.7 million and delay rentals and seismic costs of $0.6 million related primarily to expenditures in Texas State Waters of $0.3 million, $0.1 million in the Lobo Trend and $0.1 million in the Rio Vista field.

Dry hole costs. Dry hole costs were $2.0 million as a result of four exploratory dry holes for the six months ended June 30, 2005 under the successful efforts method of accounting for oil and natural gas properties.

Treating and Transportation. Treating and transportation was $2.0 million for the six months ended June 30, 2005 related to the treating and transportation related to our total natural gas production volumes of 14.5 Bcf.

Production Taxes. Production taxes as a percentage of natural gas and oil sales are approximately 2.7% for the six months ended June 30, 2005. Production taxes were primarily based on the wellhead values of production and vary across the different regions.

General and Administrative Costs. General and administrative costs of $9.7 million is net of capitalization of general and administrative costs of $3.6 million as a component of our oil and natural gas properties. Of the $9.7 million in total general and administrative costs, $5.9 million relates to salary and employee benefits and $1.3 million and $1.7 million relates to legal costs and merger and acquisition costs, respectively, associated with the sale of the oil and natural gas business to the Company.

Interest (income) expense. Interest (income) expense was $7.0 million related to intercompany debt with Calpine Corporation of $92.9 million offset by capitalized interest of $(0.7) million.

Other (Income) Expense. Other (income) expense of $0.2 million relates to investment income from an equity interest for the six months ended June 30, 2005.

Provision (Benefit) for Income Taxes. The effective tax rate for the six months ended June 30, 2005 was 38.1%. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate due primarily to state taxes.

Net Income. Our predecessor, had total revenue of $103.8 million on total volumes of 15.5 Bcfe for the six months ended June 30, 2005. Operating income was $36.9 million or 35.5% of total revenue and included work

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over cost and ad valorem taxes of $0.22 per Mcfe and $0.22 per Mcfe, respectively due to higher taxes in South Texas and a special reclamation tax in California, as well as, exploration expense of $2.4 million and exploratory dry hole expense of $2.0 million, both of which were expensed as incurred based on the successful efforts method of accounting. Total net other expense was interest expense of $7.0 million on intercompany debt of $92.9 million offset by capitalized interest of $(0.7) million. Overall, the net income was $18.7 million or 18% of total revenue.

Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Predecessor

(In thousands)	Year Ended December 31, 2004	Year Ended December 31, 2003	Net Change Increase (Decrease)	Net Change % Increase (Decrease)
Total revenue	$ 248,006	$ 279,916	$ (31,910)	-11.4%
Lease operating expense	30,785	29,586	1,199	4.1%
Depreciation, depletion and amortization	81,590	72,766	8,824	12.1%
Exploration expense	5,352	4,105	1,247	30.4%
Dry Hole costs	2,088	12,624	(10,536)	-83.5%
Impairment	202,120	2,931	199,189	6795.9%
Treating and transportation	3,509	4,759	(1,250)	-26.3%
Affiliated Marketing fees	1,887	2,856	(969)	-33.9%
Production taxes	4,322	3,725	597	16.0%
General and administrative costs	19,416	16,736	2,680	16.0%
Interest expense with affiliates, net of amount capitalized	28,034	19,050	8,984	47.2%
Interest income	(726)	(62)	(664)	1071.0%
Other (income) expense, net	(3,010)	(547)	(2,463)	450.3%
Provision (benefit) for income taxes	(48,525)	44,508	(93,033)	-209.0%
Discontinued operations, net of taxes	68,440	4,405	64,035	1453.7%
Cumulative effect of change in accounting principle, net of taxes		156	(156)	-100.0%
Net Income (Loss)	$ (10,396)	$ 71,440	$ (81,836)	-114.6%
Production:				
Gas (Bcf)	37.3	49.6	(12.3)	(24.8)%
Oil (Mbbl)	600.0	434.0	166.0	38.2%
Total Equivalents (Bcfe)	40.9	52.2	(11.3)	(21.6)%
$ per unit:				
Avg. Gas Price per Mmcfe	$ 6.02	$ 5.38	$ 0.64	11.9%
Avg. Oil Price per Mbbl	39.08	29.67	9.41	31.7%
Avg. Equivalents per Mmcfe	6.06	5.36	0.70	13.1%
Avg. operating expense per Mmcfe	0.75	0.57	0.18	31.6%
Avg. transportation & marketing per Mmcfe	0.13	0.15	(0.02)	-13.3%
Avg. production tax expense per Mmcfe	0.11	0.07	0.04	57.1%
Avg. G&A per Mmcfe	0.48	0.32	0.16	50.0%
Avg. DD&A per Mmcfe (excluding impairments)	$ 2.00	$ 1.39	$ 0.61	43.9%

Total Revenue. Production revenue decreased by $31.9 million or 11.4% for the year ended December 31, 2004 as compared to the year ended December 31, 2003. Oil revenues increased by $13.0 million or 125% over 2003 due to an increase in average realized oil prices from $29.70/barrel in 2003 to $39.05/barrel in 2004 as well as an increase in production volume from 434 MBbls in 2003 to 600 MBbls in 2004. The increase in volume was

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primarily due to increased production offshore in the Gulf of Mexico in 2004. Natural gas sales revenue decreased by $45.0 million or 16.7%, in 2004 compared to 2003 primarily due to a decrease in production volumes from 2003 to 2004 by approximately 12.3 MMcf. This decrease was partially offset by an increase in natural gas prices of $0.64 per Mcf. The overall decrease in production volume was primarily due to the capital constraints of our predecessor, and its impact on our ability to further our exploration and development program to offset depleted producing wells as well as the decreased consumption of our product by our predecessor. Also, significant fluctuations in product prices significantly impact our revenue from existing properties. See Quantitative and Qualitative Disclosure about Market Risk .

Lease Operating Expense. Our predecessor s lease operating expense increased approximately $1.2 million in 2004 from $29.6 million in 2003 to $30.8 million in 2004. The $1.2 million increase is primarily due to drilling activity in the Impac field in South Texas operated by EOG Resources, Inc., which resulted in an increase in non-operated lease operating expense. Slight increases in salt water disposal costs (primarily in California), supervisory and labor costs and ad valorem taxes were offset by slight decreases in well insurance costs, outside consulting fees and well servicing costs. Therefore, a decrease in production did not significantly reduce these types of costs. In addition, we will not develop our acreage in Kansas and Missouri and will let the relevant leases expire in accordance with their terms. These leases do not meet our minimum economic guidelines and their lease costs were insignificant.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) was $81.6 million in 2004 compared to $72.8 million in 2003 mainly due to the addition of 20 new wells in the Impac field in South Texas during 2004. Under successful efforts accounting, depletion expense is separately computed for each field. The capital expenditures for proved properties for each field compared to the proved reserves corresponding to each field to determine a depletion rate for current production. The DD&A rate in South Texas went from approximately $2.60 per Mcfe in 2003 to approximately $3.50 per Mcf in 2004 as the costs associated with drilling these wells increased significantly relative to the reserves added during the period.

Exploration Expense. Exploration costs increased $1.3 million to $5.4 million in 2004 as our predecessor had slightly more exploration activity in 2004 over 2003. In addition, the costs of exploration increased in 2004.

Dry Hole Costs. Dry hole costs were $2.1 million in 2004 compared to $12.6 million in 2003. Our predecessor had eight dry holes in 2003 compared to four in 2004 and correspondingly, the costs of each of the dry holes in 2003 were higher than 2004.

Proved Property Impairment. During 2004, our predecessor revised downward its estimate of proved reserves by a total of approximately 58 Bcfe, or 12% as of December 31, 2004. Approximately 69% of the total revision was attributable to the downward revision of the estimate of proved reserves in the South Texas fields and to a smaller extent unanticipated well performance decline in offshore fields. The remaining 31% of the total revision was primarily due to the downward revision of our predecessor s estimate of proved reserves in California of 17%, Other Onshore of 10% and Gulf of Mexico of 4%. The downward revisions of our predecessor s estimates were based on the independent reservoir engineer s year-end reserve report, which reflected production results and drilling activity that occurred during 2004 and used historical field level decline curves. Due to significant capital constraints by our predecessor, drilling activity was minimized and correspondingly the estimate of proved reserves could not be supported through drilling success or future capital activity and the downward revision was required. In addition, under the successful efforts method of accounting for oil and natural gas properties, individual assets are grouped at the lowest level for which there are identifiable cash flows. With minimal drilling activity and the evaluation of cash flows at this level, proved reserves for South Texas and California fields and the Gulf of Mexico had to be revised downward at each individual field level. As a result of the decreases, primarily in proved undeveloped reserves, a non-cash impairment charge of approximately $202.1 million was recorded for the year ended December 31, 2004. For the year ended December 31, 2003, the impairment charge recorded was $2.9 million related to the downward revision of the estimate of proved reserves in certain fields primarily in Mississippi and Louisiana.

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Treating and Transportation. Treating and transportation decreased $1.3 million or 26.3% from $4.8 million in 2003 to $3.5 million for 2004. This decrease is primarily as a result of a decrease in production volumes in 2004 as compared to 2003.

Affiliated Marketing Fees. Affiliated marketing fees decreased $1.0 million or 34.5% to $1.9 million 2004. This is primarily due to a decrease in the contract rate from 0.75% to 0.62% charged by Calpine Producer Services.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were 1.7% in 2004 and 1.3% in 2003. Production taxes are primarily based on the wellhead values of production and vary across the different regions. Production taxes increased as a result of accrued severance taxes in 2004 related to our increased drilling activity in our south Texas properties.

General and Administrative Costs. General and administrative costs increased $2.7 million from $16.7 million in 2003 to $19.4 million in 2004. The increase is primarily due to higher wages and bonuses in 2004. Corporate overhead allocation contributed to the increase as well, resulting from higher costs for facilities and rent due to the move of our corporate offices in February 2004. General and administrative costs include stock-based compensation granted to our employees by the predecessor. On January 1, 2003, the predecessor adopted the fair market value method of accounting for stock-based compensation pursuant to SFAS No. 123. Stock compensation expense of $0.8 million and $0.1 million was recorded in 2004 and 2003, respectively.

Interest Expense with Affiliates. Interest expense with affiliates increased as a result of increased interest rates related to average affiliated debt balances and as result of lower capitalization of interest expense in 2004 when compared to 2003. Interest rates on affiliated party debt ranged from 8.75% to 9.05% in 2004 compared to 2003 in which the rate was 8.75% for the entire year. Capitalized interest was $20.2 million in 2003 compared with $0.7 million in 2004. Properties classified as undeveloped in 2003 were developed and classified as proved properties in 2004, capitalized interest decreased from year to year thus resulting in the decrease in capitalized interest.

Other (Income) Expense. In 2003, other (income) expense of $0.6 million consisted of a $1.1 million gain on sale of certain Oklahoma properties to Loto Energy, LLC offset by $0.5 million project development expense relating to a canceled business opportunity in Europe. The increase in 2004 of $2.4 million was primarily due to the gains on sales of the Sargent South field and certain Oklahoma properties to BV Production I, L.P.

Provision (Benefit) for Income Taxes. For 2004 and 2003, the effective rate was 38.1% and 40.0%, respectively. The effective tax rate in all periods is the result of the earnings in various domestic tax jurisdictions that apply a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to state taxes. Future effective tax rates could be adversely affected if earnings are lower than anticipated, if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities after any related litigation.

Gain on Discontinued Operations, Net of Tax. In September 2004, we completed the sale of our Rocky Mountain natural gas properties that were primarily concentrated in the two geographic areas of the Colorado Piceance Basin and the New Mexico San Juan Basin. As a result of the sale, the predecessor recorded income from discontinued operations, net of tax of $68.4 million, including a pre-tax gain of approximately $103.7 million.

Cumulative Effect of Change in Accounting Principle. The predecessor adopted Statement of Financial Accounting Standard (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143), as of January 1, 2003. SFAS No. 143 requires us to record the fair market value of a liability for an asset retirement obligation (ARO), net of salvage value, in the period in which it is incurred. Upon adoption of SFAS No. 143, the predecessor recorded a liability for the present value of all legal obligations associated with the retirement of

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tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS No. 143, a cumulative effect of a change in accounting principle of $0.1 million was also recorded in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost.

Net Income. In addition to fluctuations in oil and natural gas production and sales prices, our net income can vary significantly from period to period because of events or circumstances which trigger recognition of expenses for unsuccessful wells or impairments of properties. Further, we calculate certain expenses, such as depletion and depreciation, using estimates of oil and natural gas reserves that can vary significantly.

The net loss in 2004 was primarily due to the impairment charge of $202.1 million recorded in the fourth quarter of 2004. The evaluation performed by the predecessor indicated that certain fields in South Texas and Gulf of Mexico had net book values in excess of the undiscounted future net cash flows associated with their proved NYMEX oil and natural gas property reserve estimates, thus requiring that the net book values of those properties be written down to fair market value based on discounted cash flows. Since the proved property impairment is determined by the predecessor on a field-by-field basis, the impairment charge may vary significantly between years based on each year s results.

The effect of the non-cash impairment charge was partially offset by a tax benefit and the gain on sale of discontinued operations. The gain on sale of discontinued operations was a result of the sale of our natural gas properties in the New Mexico San Juan Basin and Colorado Piceance Basin. Net income was also impacted by an increase in affiliated interest expense due to the increase in the inter-company borrowing rate in the fourth quarter of 2004.

Liquidity and Capital Resources

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We will actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of our production thereby mitigating our exposure to price declines, but will also limit our earnings potential in periods of rising natural gas prices. This derivative transaction activity will allow us the flexibility to continue to execute our capital plan if prices decline during the period our derivative transactions are in place. In addition, the majority of our capital expenditures will be discretionary and could be curtailed if our cash flows declined from expected levels. In connection with entering into our credit facilities, we entered into a series of natural gas fixed-price swaps for a significant portion of our expected production through 2009. Consistent with our hedge policy, in December 2005, we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for approximately 10,000 MMBtu per day which represents approximately 10% of our 2006 natural gas production based on the Netherland Sewell reserve report at December 31, 2005. Additionally, we may enter into other agreements including fixed-price, forward price, physical purchase and sales contracts, futures, financial swaps, option contracts and put options.

Senior Secured Revolving Line of Credit. BNP Paribas, in July 2005 provided us with a senior secured revolving line of credit concurrent with the acquisition in the amount of up to $400 million. This revolving line of credit was syndicated to a group of lenders on September 27, 2005. Availability under the revolver is restricted to the borrowing base, which initially was $275 million and was reset to $325 million, upon amendment, as a result of the hedges put in place in July 2005 and the favorable effects of the exercise of the over-allotment option we granted through which we received $70 million of funds (net of transaction fees). In July 2005, we repaid $60 million of the $225 million in original borrowings on the Revolver. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements. Amounts outstanding under the revolver bear interest, as amended, at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00%. Such margins will fluctuate based on the

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utilization of the facility. Borrowings under the Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the PV-10 reserve value, a guaranty by all of our domestic subsidiaries, a pledge of 100% of the stock of domestic subsidiaries, and a lien on cash securing the Calpine gas purchase and sale contracts. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. At December 31, 2005, our current ratio was 4.6 to 1.0 and our leverage ratio was 1.5 to 1.0. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance

with all covenants at December 31, 2005. All amounts drawn under the revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $160 million at December 31, 2005.

Second Lien Term Loan. BNP Paribas, in July 2005, also provided us with a second lien term loan concurrent with the acquisition, in the amount of $100 million. On September 27, 2005, we repaid $25 million of borrowings on the Term Loan, reducing the balance to $75 million and syndicated such loan to a group of lenders including BNP Paribas. Borrowings under the term loan initially bore interest at LIBOR plus 5.00%. As a result of the hedges put in place in July 2005 and the favorable effects of our private equity placement, as described above, the interest rate for the second lien term loan has been reduced to LIBOR plus 4.00%. The loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. At December 31, 2005, our asset coverage ratio was 2.2 to 1.0 and our leverage ratio was 1.5 to 1.0. In addition, we will be subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2005. The revised principal balance is due and payable on July 7, 2010.

Cash Flows

	Successor	**Predecessor**		
	Six Months Ended December 31,	**Six Months Ended June 30,**	**Year Ended December 31,**	
	2005	**2005**	**2004**	**2003**
	(In thousands)			
Cash flows provided by operating activities	$ 63,744	$ 59,379	$ 125,600	$ 145,095
Cash flows used in investing activities	(943,246)	(30,645)	164,433	(77,343)
Cash flows provided by (used in) financing activities	979,226	(27,239)	(290,334)	(71,498)
Net increase (decrease) in cash and cash equivalents	$ 99,724	$ 1,495	$ (301)	$ (3,746)

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation expense and administrative expenses.

Net cash provided from operations for the six months ended December 31, 2005 was $63.7 million generated from total production of 13.5 Bcfe with revenue of $113.1 and net income of $17.5 million. Natural gas prices averaged $8.23 per Mcf, including the effects of hedging, and oil averaged $59.52 per Bbl during this period.

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Net cash provided from operating activities for the six months ended June 30, 2005 was $59.4 million generated from total production of 15.5 MMcfe with revenue of 103.8 and net income of $18.7 million. Natural gas prices averaged $6.59 per Mcf and oil averaged $49.86 per Bbl during this period.

Net cash provided by operating activities for the year ended December 31, 2004 decreased $19.5 million from December 31, 2003. The decrease is primarily due to lower production volumes for the year ended December 31, 2003 and 2004, respectively that were slightly offset by higher commodity prices. Production volumes decreased 22% from 52.2 Bcfe to 40.9 Bcfe for the year ended December 31, 2003 and 2004, respectively. The average realized prices increased 12% from $5.38 per Mcf in 2003 to $6.02 per Mcf in 2004.

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

Cash used in investing activities for the six months ended December 31, 2005 was $943.2 million primarily relating to the acquisition of the domestic oil and gas business of Calpine in the net cash amount of $910 million (excluding fees, purchase price adjustments and expenses) and $32 million in capital expenditures spent after the acquisition. We withheld approximately $75 million from the aggregate purchase price as the allocated dollar amount for the non-consent properties, which amount is essentially equivalent to the PV-10 value of those properties at April 30, 2005, the date of the modified roll forward of our proved reserves by Netherland, Sewell & Associates, Inc. If the assignment of these cured non-consent properties does not occur, the portion of the purchase price we held back pending obtaining consent will be retained by us and will be available to us for general corporate purposes.

Cash used in investing activities for the six months ended June 30, 2005 was $30.6 million related to capital expenditures of $32.2 million related to drilling and completion work and lease acquisitions less sale of assets.

Cash used in investing activities increased by $241.8 million from 2003 to 2004 primarily due to the completed sale of our Rocky Mountain natural gas properties that were primarily concentrated in the two geographic areas of the Colorado Piceance Basin and the New Mexico San Juan Basin. As a result of the sale, Calpine recorded income from discontinued operations, net of tax of $68.4 million.

Financing Activities. The primary driver of cash provided (used) in financing activities is equity transactions, the acquisition of new debt facilities or increase in intercompany notes payable and corresponding repayments of debt.

Net cash used in financing activities for the six months ended December 31, 2005 was $979.2 million. This was due to receipt of $800 million in equity offering proceeds net of $55.6 million in transaction fees and draws on our $325 million senior credit facility subsequently used for the acquisition of the oil and natural gas properties of Calpine, operating needs, the repayment of $85.0 million of long-term debt and $5.1 million of deferred loan costs.

Net cash used in financing activities for the six months ended June 30, 2005 was comprised of repayments of notes to affiliates totaling $27.2 million.

Net cash used in financing activities increased $218.8 million from $71.5 million for the year ended December 31, 2003 to $290.3 million for the year ended December 31, 2004. The variance is due primarily to cash used in discontinued operations of approximately $219 million, resulting from asset sales.

Commodity Prices and Related Hedging Activities

The energy markets have historically been very volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. To mitigate our exposure to changes in

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commodity prices, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of certain derivative instruments including fixed price swaps, costless collars, and put options. Although not risk free, we believe this policy will reduce our exposure to commodity price fluctuations and thereby achieve a more predictable cash flow. Consistent with this policy, and in connection with entering into our credit facilities in July 2005, we have entered into a series of natural gas fixed-price swaps, which are intended to establish a fixed price for a significant portion of our expected natural gas production through 2009. The fixed-price swap agreements we have entered into require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments.

Consistent with our hedge policy, in December 2005 we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for a portion of our expected production in 2006. If the floating price each month at the settlement point is greater than the ceiling price, we pay the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pays us an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month. See Item 7A. Quantitative and Qualitative Disclosure About Market Risk .

In accordance with SFAS 133, as amended, all derivative instruments are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions every three months, consistent with documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges are included in other revenue.

Our current hedge positions are with counterparties that are lenders in our credit facilities. This allows us to securitize any margin obligation resulting from a negative change in the fair market value of the derivative contracts in connection with our credit obligations and eliminate the need for independent collateral postings. As of December 31, 2005, we had no deposits for collateral.

The following table sets forth the results of third party hedging transactions settled for the six months ended December 31, 2005:

Natural gas	
Quantity settled (MMBtu)	7,956,000
Increase (Decrease) in Natural Gas Sales Revenue	$ (16,575,709)

In connection with the acquisition, we did not acquire any derivative positions or hedging agreements.

Interest Rate Risks

Borrowings under our term and revolving line of credit facilities mature on July 7, 2009 and bear interest at a LIBOR-based rate. This exposes us to risk of earnings loss due to changes in market rates. Although we continue to evaluate the risks related to this exposure, we have not entered into any interest rate swap agreements to mitigate such risk as of December 31, 2005. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into interest rate swap agreements in the future.

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Capital Requirements

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 in Item 8. 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 $0.6 million of capitalized

interest, $1.6 of corporate other 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.

After the completion of the acquisition of the oil and natural gas properties and our separation from Calpine, our capital expenditures for the six months ended December 31, 2005 increased by approximately $33 million in

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relation to what Calpine spent in the first six months of 2005. We expect to continue this trend of increased capital expenditures in 2006 with a capital budget for the year ended December 31, 2006 of approximately $199 million.

We expect to fund this capital expenditure budget out of available cash and cash flow from operations and, if necessary, from our available borrowing base under our credit facilities. If cash and cash flows are not adequate, we may not be able to fund the amounts set forth above without incurring further indebtedness or accessing the equity or debt capital markets.

Commitments and Contingencies

Commitments

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

Contractual Obligations. At December 31, 2005, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

	Payments Due by Period				
Contractual Obligations	**Total**	**2006**	**2007 to 2008**	**2009 to 2010**	**2011 and Beyond**
			(In thousands)		
Senior secured revolving line of credit	$ 165,000	$	$	$ 165,000	$
Second lien term loan	75,000			75,000	
Operating leases	15,605	1,924	3,891	3,898	5,892
Interest payments on long-term debt	65,914	16,654	33,947	15,313	
Rig commitments	18,667	17,092	1,575		
Total contractual obligations	$ 340,186	$ 35,670	$ 39,413	$ 259,211	$ 5,892

Asset Retirement Obligation. The Company also has liabilities of $9.5 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2005. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. See Note 9 of the Consolidated/Combined Financial Statements.

Purchase and Sale Agreement with Calpine. Under our purchase and sale agreement with Calpine, Calpine agreed to transfer to us certain properties, the transfer of which requires the consent of third parties. At the closing of our acquisition in July 2005, title to properties having a value of approximately $75 million remained with Calpine subject to receipt of consents. As provided in the purchase and sale agreement, we retained approximately $75 million in cash, out of the total purchase price pending completion of these assignments. At the time of the Calpine bankruptcy, we were preparing to consummate the assignments of these properties with Calpine (excluding $7.4 million relating to properties for which a preferential right has not been waived). Because of Calpine s bankruptcy, we may experience delay or frustration of our ability to complete these purchases. If these assignments do not occur, the approximately $75 million retained pending these assignments will be available to us to use for general corporate purposes.

Contingencies

The Company is party to various litigation matters arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters

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will have a material adverse effect on the Company s financial position, results of operation or cash flows. As of December 31, 2005 and 2004, a reserve for legal fees was recorded in other current liabilities on the Consolidated/Combined Balance Sheets in the amount of $0.4 million and $0.1 million, respectively.

Calpine Bankruptcy

Calpine and certain of its subsidiaries (collectively, the Debtors) filed for protection under the federal bankruptcy laws in the Southern District of New York on December 20, 2005. The Company is not presently a party to any pending litigation in connection with this bankruptcy, although counsel has filed a notice of appearance on our behalf so we may effectively monitor the proceedings. Calpine Energy Services, L.P. has continued to make the required deposits into Rosetta s margin account and to timely pay for production it purchases from the Company s subsidiaries under various supply agreements. Calpine and certain of its subsidiaries have generally continued to provide services desired by the Company under the Transition Services Agreement and Calpine Producer Services, L.P. generally is performing its obligations under the Marketing and Services Agreement with us.

There remains the possibility, however, that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the Purchase and Sale Agreement, dated July 7, 2005 by and among Calpine, the Company and various other parties signatories thereto (the Purchase Agreement) including unasserted claims and assessments with respect to (i) the still pending final closing under the Purchase Agreement and the amounts that will be payable in connection therewith, (ii) whether or not Calpine and its affiliated debtors will, in fact, perform their remaining obligations in connection with the final closing, and (iii) the ultimate disposition of certain properties (and related royalty revenues) for which third party consents to transfer had not been obtained at the time of the original closing under the Purchase Agreement. While the Company remains hopeful that it will be able to work cooperatively with Calpine so as to accomplish the delivery by Calpine of record legal title including all ancillary ministerial and administrative corrections for all non-consent properties, as well as the curative corrections for all properties which the Company paid for, all of the same being covered by the further assurances provision of the parties definitive agreements, the timing and exact details of how, when and if this will be able to be accomplished continue to remain uncertain at this early stage of Calpine s bankruptcy. The Company s management continues to believe that it is unlikely that any challenges by the Calpine debtors or their creditors to the fairness of this acquisition would be successful. At the present time, there is no pending or overtly threatened litigation in this regard. However, in the future there may be possible unasserted claims and assessments, seeking to challenge some aspect of the acquisition.

Deanne Lounsberry Duhon, et al. v. Ensearch Exploration, Inc., et al.

This lawsuit is a retained liability by Calpine. On September 10, 2004, Apache Corporation (Apache) filed a cross-claim and third party demand in the above listed matter and has named Calpine Natural Gas and Agricultural Methane in this suit. A dispute has arisen as to the division of royalties between certain groups. The plaintiffs are seeking the forfeiture from Apache of the working interest income stream from the proceeds of the production of the well in various producing intervals. Apache is seeking claims for contribution and indemnifying in the event Apache is found liable. RROLP and Agricultural Methane are currently reviewing these allegations. It is the Company s understanding that this matter has been settled for an immaterial amount.

Arbitration between Calpine Corp./RROLP and Pogo Producing Company

This is a retained liability by the predecessor. On September 1, 2004, Calpine and RROLP (collectively Calpine), sold its New Mexico oil and natural gas assets to Pogo Producing Company (Pogo). During the course of the sale, Pogo made a title defect claim (valued at approximately $1.9 million) claiming that certain leases subject to the sale had expired because of lack of production. Although Calpine has undertaken to resolve

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this matter by obtaining ratifications of a majority of the questionable leases, Pogo has been unwilling to compromise its claim for the title defect value and has invoked the arbitration provisions of the underlying purchase and sale agreement. It is the Company s understanding that Calpine has cured 85-90% of alleged title defects. The arbitration is subject to Calpine s stay and, therefore is on hold. This is a retained liability by Calpine and it is management s belief that this will have no financial impact to the Company.

Claim for Indemnification by Bill Barrett Corporation

It is the Company s understanding that this matter has been settled by Bill Barrett. Calpine still has potential contractual indemnification subject to stay. This is a retained liability by Calpine and it is management s belief that this will have no financial impact to the Company.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. The Company performed an environmental remediation study for three sites in California and correspondingly, recorded a liability, which at December 31, 2005 and 2004 was $0.7 million and $0.7, respectively. We do not expect that the outcome of our environmental matters discussed above will have a material adverse effect on the Company s financial position, results of operations or cash flows.

Participation in a Regional Carbon Sequestration Partnership

In accordance with its obligations to Calpine under the parties transition services agreement, the Company has made preliminary preparations in connection with its cooperating with Calpine to participate in a joint study in connection with the U.S. Department of Energy s (DOE) Regional Carbon Sequestration Partnership program (WESTCARB) with the California Energy Commission and the University of California, Lawrence Berkeley Laboratory. The Company has been selected by the DOE for this project. Under WESTCARB, the Company would be required to drill a carbon injection well, recondition an idle well for use as an observation well and provide WESTCARB with certain proprietary well data and technical assistance related to the evaluation and injection of carbon dioxide into a suitable natural gas reservoir in the Sacramento Basin. The Company s maximum contribution to WESTCARB is $1.0 million and will be limited to 20% of the total contributions to the project. The Company will not have any obligation under the WESTCARB project until it has entered into an acceptable contract and the project has obtained proper and necessary local, state and federal regulatory approvals, land use authorizations, and third party property rights. No accrual was recorded at December 31, 2005 as the study is still in the preliminary stage.

Related Party Transactions

Successor

During the six months ended December 31, 2005, the Company purchased accounting contract services from a firm in which a principal partner is related to an officer of the Company. Total expenditures for these services in this period were $0.6 million.

Predecessor

Calpine and certain of its affiliates entered into various agreements with respect to the domestic oil and natural gas properties. Upon acquisition of the oil and natural gas business from Calpine, these various agreements were cancelled or retired. Following is a general description of each of the various agreements in effect prior to the date of acquisition:

Agency Agreement. Calpine entered into a service agreement with Calpine Producer Services (CPS) beginning April 1, 2003. The contract was automatically renewed every year unless terminated by either party.

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CPS provided services related to the Calpine s production, including marketing, contract administration, royalty and working interest owner issues, and receipt of payments. All activities performed by CPS were performed on behalf of Calpine and under Calpine s control and direction, in exchange for a fee for services rendered. Calpine dispensed all royalty payments when CPS provided accurate and timely details. Management fees of $0.9 million for the six months ended June 30, 2005 and $1.9 million and $2.9 million are recorded as Affiliated marketing fees in the combined statements of operations for the years ended 2004 and 2003, respectively.

Natural Gas Sales. Calpine and Calpine Energy Services (CES) executed index based natural gas sales under existing master agreements. Many of these transactions were executed by CPS on behalf of Calpine; however, Calpine sold directly to CPS and CES prior to the agency agreement with CPS being executed. Oil and natural gas sales to affiliates were $81.9 million for the six months ended June 30, 2005 and $190.2 million and $223.5 million for the years ended December 31, 2004 and 2003, respectively.

Natural gas balancing activities between CES and Calpine, where Calpine bought back natural gas above the needs of CES and then re-sold that excess natural gas to third parties was recorded net to affiliated marketing fees in the combined statements of operations. The net effect of these balancing activities resulted in a gain or loss in the respective period. The net balancing cost (reduction of cost) for the years ended December 31, 2004 and 2003 was $(0.1) million and $0.3 million, respectively and for the six months ended June 30, 2005 there was no net balancing cost.

Notes Payable to Affiliates. Prior to the acquisition in July 2005, the Company and Calpine had an agreement whereby Calpine loaned the Company funds for capital expenditures, as well as, operating costs. The Company repaid the balance of the note to Calpine as excess cash was available from continuing operations and asset sales. Interest on the note was compounded monthly at an annual rate of 8.75% during 2002 and 2003 and for the period through July of 2004, when the rate became variable, raising from 9.0% in August 2004 to 9.05% in December 2004. Additionally, the Company received equipment transferred from CPN Pipeline Company (Pipeline) during 2004 that was transferred at historical cost as the transaction was between entities under common control. The Company s payable to Pipeline was subsequently transferred to Calpine and increased the note discussed above. As part of certain credit facilities entered into by Calpine, the security included direct liens on the domestic oil and natural gas properties. The balance of Notes payable to Affiliates was $127.2 million and $444.1 million at December 31, 2004 and 2003, respectively. These notes were retired at the time of acquisition of the oil and natural gas business of Calpine.

Other Services. Calpine provided general services to other subsidiaries of Calpine that were recorded in accounts receivables from affiliates on the combined balance sheets and other revenue on the combined statements of operations, which were insignificant.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

FORWARD-LOOKING STATEMENTS

In addition to historical information, this Annual Report contains forward-looking statements within the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements include any projections of earnings, revenues, asset sales, cash flow, debt levels or other financial items; any statements of the plans, strategies and objectives of management for future operation; any statements regarding future economic conditions or performance; any statements of belief; and any statements of assumptions underlying any of the foregoing. Forward-looking statements may include the words may , will , estimate , intend , believe , expect , project , forecast , plan , anticipa similar words.

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Item 7A. Quantitative and Qualitative Disclosure About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk. Our major market risk exposure is in the pricing of our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. Based on daily production for the year ended December 31, 2005, our annual income before income taxes would change by approximately $2.7 million for each $0.10 change in natural gas prices and approximately $350,000 for each $1.00 change in crude oil prices.

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

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

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

As of December 31, 2005, we had the following financial fixed price swap positions outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Natural Notional Annual Volume MMBtu	Average Fixed Price per MMBtu	Total of Proved Natural Gas Production Hedged(1)	Fair Value Gain/(Loss) (In thousands)
2006	Swap	Cash flow	45,000	16,425,000	$ 7.923	46%	$ (29,958)
2007	Swap	Cash flow	36,300	13,249,500	$ 7.617	33%	(25,817)
2008	Swap	Cash flow	30,876	11,300,616	$ 7.297	27%	(16,931)
2009	Swap	Cash flow	26,141	9,541,465	$ 6.989	26%	(10,230)
Total				50,516,581			$ (82,936)

(1) Estimated based on net gas reserves presented in the December 31, 2005 Netherland, Sewell & Associates, Inc. reserve report.

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Consistent with our hedge policy, in December 2005 we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for a portion of our expected production in 2006. If the floating price each month at the settlement point is greater than the ceiling price, we pay the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pay us an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month.

The following table describes our open costless collar transactions at December 31, 2005 by associated notional volumes and contracted ceiling and floor price at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Natural Notional Annual Volume MMBtu	Average Floor Price per MMBtu	Average Ceiling Price per MMBtu	Fair Value Gain/(Loss) (In thousands)
2006	Costless Collar	Cash flow	10,000	3,650,000	$ 8.825	$ 14.000	$ 1,110

The total of proved natural gas production hedged in 2006 for the costless collars is approximately 10% based on the December 31, 2005 reserve report prepared by Netherland, Sewell & Associates, Inc.

Interest Rate Risks. In July 2005, we entered into our credit facilities including (1) a senior secured revolving line of credit in the aggregate amount of up to $400 million (the Revolver), and (2) a senior secured second lien term loan, initially, in the aggregate amount of $100 million (the Term Loan). Both the senior secured revolving line of credit and the senior secured second lien loan were amended and syndicated on September 27, 2005.

Availability under the Revolver is restricted to a borrowing base calculation of value assigned to proved oil and natural gas reserves. The initial borrowing base was $275 million and was reset to $325 million as of the syndication date as a result of the derivative transactions and the favorable effects of our underwriters exercising the over-allotment option we granted in connection with our sale of 45,312,500 shares of our common stock, through which we received $70 million of funds (net of transaction fees), were used to repay $60.0 million of borrowings under the Revolver in July 2005 and the remainder for unspecified operating costs of our oil and natural gas properties and general and administrative costs from our oil and natural gas operations. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our derivative arrangements. Amounts outstanding under the Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00%, based on facility utilization. The Revolver will mature on July 7, 2009.

The Term Loan initially in the amount of $100 million was reduced to $75 million on the syndication date of September 27, 2005. Borrowings under the Term Loan initially bore interest at LIBOR plus 5.00%. In September 2005, $25 million of borrowings under the Term Loan were repaid. As a result of the derivative transactions and the favorable effect of our private equity placement, as described above, the interest rate for the second lien term loan has been reduced to LIBOR plus 4.00%. The Term Loan is collateralized by a second lien on all assets securing the Revolver. The Term Loan will mature on July 7, 2010.

We had availability under the facility of $160 million as of December 31, 2005. A one hundred basis point increase in each of the LIBOR rate and federal funds rate as of December 31, 2005 for both our revolver of credit and term debt would result in an estimated $2.4 million increase in annual interest expense.

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Item 8. Financial Statements and Supplementary Data.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors

and Stockholders of Rosetta Resources Inc.:

In our opinion, the consolidated balance sheet as of December 31, 2005 and the related consolidated statements of operations, of cash flows and of changes in stockholders equity and comprehensive income for the six months ended December 31, 2005 present fairly, in all material respects, the consolidated financial position of Rosetta Resources Inc. and its subsidiaries (successor, the Company) at December 31, 2005 and the results of their operations and their cash flows for the six months ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As described in Note 11 to the consolidated financial statements, the Company s former parent filed bankruptcy subsequent to the Company s acquisition of the oil and natural gas business of Calpine Corporation and Affiliates.

/s/ PricewaterhouseCoopers LLP

April 19, 2006

Houston, Texas

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Report of Independent Registered Public Accounting Firm

To the Board of Directors

and Stockholders of Rosetta Resources Inc.:

In our opinion, the combined balance sheet as of December 31, 2004 and the related combined statements of operations, of cash flows and of changes in owner s net investment for the six months ended June 30, 2005 and each of the two years in the period ended December 31, 2004 present fairly, in all material respects, the combined financial position of the Domestic Oil & Natural Gas Properties of Calpine Corporation and Affiliates (predecessor) at December 31, 2004 and the results of their operations and their cash flows for the six months ended June 30, 2005 and each of the two years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the combined financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003.

As described in Note 17 to the combined financial statements, the Company has significant transactions and relationships with related parties. Because of these relationships, it is possible that the terms of these transactions are not the same as those that would result from transactions among wholly unrelated parties.

/s/ PricewaterhouseCoopers LLP

April 19, 2006

Houston, Texas

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ROSETTA RESOURCES INC.

CONSOLIDATED/COMBINED BALANCE SHEETS

	Successor-Consolidated December 31, 2005	Predecessor-Combined December 31, 2004
	(In thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 99,724	$
Accounts receivable	40,051	11,803
Accounts receivable from affiliates		23,008
Derivative instruments	1,110	
Deferred income taxes	10,962	
Current income tax receivable	6,000	
Other current assets	9,411	3,665
Total current assets	167,258	38,476
Oil and natural gas properties, full cost, of which $37 million was excluded from amortization at December 31, 2005/successful efforts method	973,185	1,105,560
Other	2,912	5,956
	976,097	1,111,516
Accumulated depreciation, depletion, and amortization	(40,161)	(504,996)
Total property and equipment, net	935,936	606,520
Long-term accounts receivable	1,726	3,137
Deferred loan fees	4,555	
Deferred income taxes	8,594	
Other assets	1,200	8,395
Total other assets	16,075	11,532
Total assets	$ 1,119,269	$ 656,528
Liabilities, Stockholder's Equity and Owner s Net Investment		
Current Liabilities:		
Accounts payable	$ 13,442	$ 4,494
Notes payable to affiliates		127,164
Royalties payable	30,039	10,768
Current income tax payable		114,589
Derivative instruments	29,957	
Interest payable	133	
Prepayment on gas sales	14,528	
Other current liabilities	13,736	21,969
Total current liabilities	101,835	278,984
Long-term liabilities		

Derivative instruments	52,977	
Long-term debt	240,000	
Asset retirement obligation	9,034	8,384
Deferred income taxes		145,709
Total liabilities	403,846	433,077
Commitments and Contingencies (Note 11)		
Stockholders' Equity and Owner's Net Investment:		
Common Stock, $0.001 par value, 150,000,000 shares authorized, 50,003,500 issued and outstanding	50	
Additional paid-in capital	748,569	
Owner s net investment		223,451
Accumulated other comprehensive loss	(50,731)	
Retained earnings	17,535	
Total stockholders' equity and owner's net investment	715,423	223,451
Total liabilities, stockholders' equity and owner's net investment	$ 1,119,269	$ 656,528

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

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ROSETTA RESOURCES INC.

CONSOLIDATED/COMBINED STATEMENTS OF OPERATIONS

	Successor-Consolidated Six Months Ended December 31, 2005	Predecessor-Combined Six Months Ended June 30, 2005	Predecessor-Combined Year Ended December 31, 2004	Predecessor-Combined Year Ended December 31, 2003
	(In thousands, except share and per share amounts)			
Revenues:				
Oil sales	$ 11,046	$ 8,166	$ 23,443	$ 10,386
Natural gas sales	102,044	13,637	34,129	45,844
Oil and natural gas sales to affiliates		81,952	190,215	223,464
Other revenue	14	76	219	222
Total revenues	113,104	103,831	248,006	279,916
Operating Costs and Expenses:				
Lease operating expense	15,674	16,629	30,785	29,586
Depreciation, depletion, and amortization	40,500	30,679	81,590	72,766
Exploration expense		2,355	5,352	4,105
Dry hole costs		1,962	2,088	12,624
Impairment			202,120	2,931
Treating and transportation	1,286	1,998	3,509	4,759
Affiliated marketing fees		913	1,887	2,856
Marketing fees	1,379			
Production taxes	3,975	2,755	4,322	3,725
General and administrative costs	14,687	9,677	19,416	16,736
Total operating costs and expenses	77,501	66,968	351,069	150,088
Operating income (loss)	35,603	36,863	(103,063)	129,828
Other (income) expense				
Interest expense with affiliates, net of interest capitalized		6,995	28,034	19,050
Interest expense, net of interest capitalized	8,216			
Interest income	(1,837)	(516)	(726)	(62)
Other (income) expense, net	152	207	(3,010)	(547)
Total other expense	6,531	6,686	24,298	18,441
Income (loss) before provision for income taxes, discontinued operations and cumulative effect of change in accounting principle	29,072	30,177	(127,361)	111,387
Provision (benefit) for income taxes	11,537	11,496	(48,525)	44,508
Income (loss) before discontinued operations and cumulative effect of change in accounting principle	17,535	18,681	(78,836)	66,879
Discontinued operations, net of taxes			68,440	4,405
Cumulative effect of change in accounting principle, net of taxes				156
Net income (loss)	$ 17,535	$ 18,681	$ (10,396)	$ 71,440
Earnings (loss) per share:				
Basic				
	$ 0.35	$ 0.37	$ (1.58)	$ 1.34

Income (loss) before provision for income taxes, discontinued operations and cumulative effect of change in accounting principle								
Discontinued operations	$		$		$	1.37	$	0.09
Cumulative effect of change in accounting principle	$		$		$		$	
Net income (loss)	$	0.35	$	0.37	$	(0.21)	$	1.43
Diluted								
Income (loss) before provision for income taxes, discontinued operations and cumulative effect of change in accounting principle	$	0.35	$	0.37	$	(1.58)	$	1.33
Discontinued operations	$		$		$	1.37	$	0.09
Cumulative effect of change in accounting principle	$		$		$		$	
Net income (loss)	$	0.35	$	0.37	$	(0.21)	$	1.42
Weighed average shares outstanding:								
Basic		50,003,006		50,000,000		50,000,000		50,000,000
Diluted		50,188,957		50,160,481		50,000,000		50,160,481

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

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ROSETTA RESOURCES INC.

CONSOLIDATED/COMBINED STATEMENTS OF CASH FLOWS

	Successor-Consolidated	Predecessor-Combined		
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
	(In thousands)			
Cash flows from operating activities				
Net income	$ 17,535	$ 18,681	$ (10,396)	$ 71,440
Income from discontinued operations, net of taxes			(68,440)	(4,405)
Net income from continuing operations	17,535	18,681	(78,836)	67,035
Adjustments to reconcile net income from continuing operations to net cash from operating activities				
Depreciation, depletion and amortization	40,500	30,679	81,590	72,766
Affiliate interest expense		(6,995)	(28,034)	(19,050)
Impairment			202,120	2,931
Deferred income taxes	11,537	2,874	(137,838)	17,796
Amortization of deferred loan fees recorded as interest expense	590			
Income from unconsolidated investments	(241)	(161)	(324)	(81)
Stock compensation expense	4,248			
Other non-cash changes		99	4,856	(21)
Cumulative Effect of Change in Accounting Principle				2,219
Change in operating assets and liabilities:				
Accounts receivable	(40,051)	2,378	5,486	(13,697)
Accounts receivable from affiliates		6,298	(293)	(13,488)
Current income tax assets				1,436
Current income tax receivable	(6,000)			
Prepaid expenses	(9,411)	2,563	(2,130)	2,957
Long-term accounts receivable	(1,726)		(3,137)	
Royalties payable	30,039	(1,406)	(6,842)	17,390
Accounts payable	13,442	(4,494)	1,517	12
Interest payable	133			
Current income taxes payable		8,622	89,313	25,276
Other current liabilities	3,149	241	(6,266)	(11,074)
Cash provided by continuing operating activities	63,744	59,379	121,182	152,407
Cash provided by (used in) discontinued operations			4,418	(7,312)
Net cash provided by operating activities	63,744	59,379	125,600	145,095

(continued)

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ROSETTA RESOURCES INC.

CONSOLIDATED/COMBINED STATEMENTS OF CASH FLOWS (Continued)

Cash flows from investing activities				
Acquisition of assets	(910,064)			
Purchases of property and equipment	(32,994)	(32,202)	(68,386)	(102,700)
Disposals of property and equipment	13	1,447	14,536	40,645
Deposits	(201)			(100)
Other		110	(83)	23
Cash used in continuing investing activities	(943,246)	(30,645)	(53,933)	(62,132)
Cash provided by (used in) discontinued operations			218,366	(15,211)
Net cash provided by (used in) investing activities	(943,246)	(30,645)	164,433	(77,343)
Cash flows from financing activities				
Equity offering proceeds	800,000			
Equity offering transaction fees	(55,629)			
Borrowings on term loan debt and revolving credit facility	325,000			
Payments on debt term loan debt and revolving credit facility	(85,000)			
Increase (decrease) in long-term liability				21
Purchase of performance bonds				(6,351)
Deferred loan fees	(5,145)			
Decrease in capital lease			(1,420)	(164)
Notes payable to affiliates		(27,239)	(70,226)	(65,004)
Cash provided by (used in) continuing financing activities	979,226	(27,239)	(71,646)	(71,498)
Cash used in discontinued operations			(218,688)	
Net cash provided by (used in) financing activities	979,226	(27,239)	(290,334)	(71,498)
Net increase (decrease) in cash	99,724	1,495	(301)	(3,746)
Cash and cash equivalents, beginning of period			301	4,047
Cash and cash equivalents, end of period	$ 99,724	$ 1,495	$	$ 301
Supplemental disclosures:				
Cash paid for interest expense, net of capitalized interest	$ (8,057)	$	$	$
Cash paid for income tax	$ 6,000	$	$	$
Supplemental non-cash transactions:				
Oil and gas properties acquired from affiliates in exchange for notes payable to affiliates	$	$	$ 10,100	$
Net capital expenditures included in current liabilities	$ 33,470	$	$	$

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

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ROSETTA RESOURCES INC.

CONSOLIDATED/COMBINED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME AND CHANGES IN OWNER S NET INVESTMENT

Predecessor	Shares	Amount	Additional Paid-In Capital	Accumulated Other Comprehensive (Loss)	Retained Earnings	Owner s Net Investment	Total Stockholders Equity & Owner's Net Investment
			(In thousands, except share amounts)				
Balance at January 1, 2003		**$**	**$**	**$**	**$**	**$ 162,407**	**$ 162,407**
Net income						71,440	71,440
Balance at December 31, 2003		**$**	**$**	**$**	**$**	**$ 233,847**	**$ 233,847**
Net loss						(10,396)	(10,396)
Balance at December 31, 2004		**$**	**$**	**$**	**$**	**$ 223,451**	**$ 223,451**
Net income						18,681	18,681
Balance at June 30, 2005		**$**	**$**	**$**	**$**	**$ 242,132**	**$ 242,132**
Successor							
Balance at July 1, 2005		**$**	**$**	**$**	**$**	**$**	**$**
Issuance of common stock, net of offering costs	50,003,500	50	744,321				744,371
Vesting of restricted stock			4,248				4,248
Comprehensive income:							
Net Income					17,535		17,535
Change in fair value of derivative hedging instruments				(98,400)			(98,400)
Hedge settlement reclassified to income				16,576			16,576
Tax (provision)/benefit related to cash flow hedges				31,093			31,093
Comprehensive income							(33,196)
Balance at December 31, 2005	**50,003,500**	**$ 50**	**$ 748,569**	**$ (50,731)**	**$ 17,535**	**$**	**$ 715,423**

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

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ROSETTA RESOURCES INC.

NOTES TO CONSOLIDATED/COMBINED FINANCIAL STATEMENTS

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (successor, the Company) is comprised of the domestic oil and natural gas properties of Calpine Corporation and affiliates (predecessor, Calpine), acquired in July 2005 and is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States, both onshore and offshore in the Gulf of Mexico. In October 1999, Calpine, a Delaware corporation and the Company s parent 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 and 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 Natural Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. Sheridan was merged into Calpine in April 2000, 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.

(2) Acquisition of Calpine Oil and Natural Gas Business

On July 7, 2005, Rosetta Resources Inc. acquired the oil and natural gas business of Calpine for approximately $910 million. This acquisition was funded with the issuance of common stock totaling $725 million and $325 million of debt from our credit facilities. The transaction was accounted for under the purchase method in accordance with SFAS 141. The results of operations were included in the Company s financial statements effective July 1, 2005 as the operating results in the intervening period are not significant. The preliminary purchase price was calculated as follows:

The preliminary purchase price was calculated as follows (In thousands):

Calculation of Preliminary Purchase Price:	
Cash from equity offering	$ 725,000
Proceeds from revolver	225,000
Proceeds from term loan	100,000
Other purchase price costs (e.g. fees, etc.)	(53,389)
Transaction adjustments (purchase price adjustments)	(11,556)
Transaction adjustments (non-consent properties)	(74,991)
Total preliminary purchase price	$ 910,064

Other purchase price costs relate primarily to professional fees of $3.8 million and other direct transaction costs of $49.5 million.

Transaction adjustments (purchase price adjustments) is an amount agreed upon by Calpine Corporation and the Company to cover potential costs and/or revenues that will be adjusted to actual upon the final closing of the transaction. The Company does not anticipate a significant adjustment to this amount at final closing.

Transaction adjustments (non-consent properties) relate to properties which required third party consents or waivers of preferential purchase rights necessary in order to affect transfer of title. At July 7, 2005, we withheld $75 million of the purchase price with respect to these non-consent properties. These funds are held by us and, despite Calpine s bankruptcy filing, management believes that it remains likely that conveyance of substantially all of these non-consent properties will occur ($7.4 million being subject to an exercised preference purchase

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right based on the PV-10 value at December 31, 2005). Upon conveyance, such additional purchase price will be paid to Calpine and will be incremental to the preliminary purchase price of $910 million. We have excluded the effects of the operating results for the non-consent properties from our pro forma results of operations presented below for the years ended December 31, 2005 and December 31, 2004, respectively and our actual results for 2005. If the assignment of these properties does not occur, the portion of the purchase price we withheld pending obtaining consent for these properties will be available to us for general corporate purposes or to acquire other properties.

The following is the allocation of the purchase price to specific assets acquired and liabilities assumed based on estimates of fair values and costs. There was no goodwill associated with the transaction (In thousands):

Current assets	$ 1,794
Non-current assets	5,087
Properties, plant and equipment	925,141
Current liabilities	(14,390)
Long-term liabilities	(7,568)
	$ 910,064

The purchase price allocation is preliminary in nature, subject to additional information regarding title for non consent properties. Management does not expect the final purchase price allocation to differ materially, with the exception of the conveyance of the non-consent properties discussed above.

The unaudited pro forma information below for the years ended December 31, 2005 and 2004 assume the acquisition of Calpine s domestic oil and natural gas business and the related financings occurred at the beginning of the periods presented. We believe the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions. The unaudited pro forma information does not purport to represent what our results of operations would have been if such transactions had occurred on such date.

	Year Ended December 31, 2005	Year Ended December 31, 2004
	(In thousands) (Unaudited)	
Revenues	$ 207,501	$ 223,168
Net income	$ 26,437	$ 45,882
Basic earnings per common share	$ 0.53	$ 0.92
Diluted earnings per common share	$ 0.53	$ 0.91

(3) Summary of Significant Accounting Policies

All significant accounting policies discussed below are applicable to both the Company and Calpine unless otherwise noted below.

Principles of Consolidation/Combination and Basis of Presentation. The Company purchased the domestic oil and natural gas business of Calpine which was separately accounted for and managed through direct and indirect subsidiaries of Calpine. As a result, the combined financial position as of December 31, 2004 and the results of operations for the six months ended June 30, 2005 and the two year periods ended December 31, 2004 and 2003 of this domestic oil and gas business comprise the predecessor financial statements.

The accompanying combined financial statements have been prepared from the historical accounting records of the domestic oil and natural gas business of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and gas business. All assets and liabilities specifically identified with

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the businesses described above have been included in the combined balance sheet. The owner s net investment has been presented in lieu of stockholder s equity in the combined financial statements. The combined financial information included herein includes certain allocations based on the historical activity levels to reflect the combined financial statements in accordance with accounting principles generally accepted in the United States of America and may not necessarily reflect the financial position, results of operations and cash flows of the Company in the future or as if we had existed as a separate, stand-alone business during the periods presented. The allocations consist of general and administrative expenses (employee payroll and related benefit costs, building lease expense, among other items) incurred on behalf of Calpine. The allocations have been made on a reasonable basis and have been consistently applied for each period presented.

The accompanying consolidated financial statements as of December 31, 2005 and for the six months ended December 31, 2005 contain the accounts of Rosetta Resources Inc. and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions and comprise the successor financial statements.

Use of Estimates in Preparation of Financial Statements. The preparation of the consolidated/combined financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes, capitalization of interest, the outcome of pending litigation, dismantlement and abandonment costs, estimates to certain oil and gas revenues and expenses and estimates of proved oil and natural gas reserve quantities used to calculate depletion, depreciation and impairment of proved oil and natural gas properties and equipment.

Fair Value of Financial Instruments. The carrying value of cash and cash equivalents, accounts receivable, accounts payable, notes payable and other payables approximate their respective fair market values due to their short maturities. As of December 31, 2005, the carrying value of our debt, was approximately $240 million. The fair value of our debt approximates the carrying value because the interest rates are based on floating rates identified by reference to market rates and because the interest rates charged are at rates at which we can currently borrow.

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

Allowance for Doubtful Accounts. The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for balances greater than 90 days outstanding. At December 31, 2004, Calpine had an allowance for its aged receivables of $0.6 million. It is the Company s belief that there are no balances in accounts receivable that will not be collected and that an allowance was unnecessary at December 31, 2005.

Property, Plant and Equipment, Net.

In connection with the Company s separation from Calpine, the Company adopted the full cost method of accounting for oil and natural gas properties beginning July 1, 2005. Under the full cost method, all costs

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incurred in acquiring, exploring, and developing properties within a relatively large geopolitical cost center are capitalized when incurred and are amortized as mineral reserves in the cost center are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with offshore U.S. operations, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and gas producing activities are regarded as integral to the acquisition, discovery, and development of whatever reserves ultimately result from the efforts as a whole, and are thus associated with the Company s reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities and certain costs related to general corporate overhead or similar activities. We capitalized $3.5 million of internal costs for the six months ended December 31, 2005. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment rather than amortized. Upon evaluation, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally included in the full cost pool unless the entire pool is sold.

Capitalized costs and estimated future development costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. The Company assesses the impairment for oil and natural gas properties for the full cost pool quarterly using a ceiling test to determine if impairment is necessary. Specifically, the net unamortized costs for each full cost pool less related deferred income taxes should not exceed the following: (a) the present value, discounted at 10%, of future net cash flows from estimated production of proved oil and gas reserves plus (b) all costs being excluded from the amortization base plus (c) the lower of cost or estimated fair value of unproved properties included in the amortization base less (d) the income tax effects related to differences between the book and tax basis of the properties involved. The present value of future net revenues should be based on current prices, with consideration of price changes only to the extent provided by contractual arrangements, as of the latest balance sheet presented. The full cost ceiling test must take into account the prices of qualifying cash flow hedges in calculating the current price of the quantities of the future production of oil and gas reserves covered by the hedges as of the balance sheet date. In addition, the use of the hedge-adjusted price should be consistently applied in all reporting periods and the effects of using cash flow hedges in calculating the ceiling test, the portion of future oil and gas production being hedged, and the dollar amount that would have been charged to income had the effects of the cash flow hedges not been considered in calculating the ceiling limitation should be disclosed. Any excess is charged to expense during the period that the excess occurs. Application of the ceiling test is required for quarterly reporting purposes, and any write-downs cannot be reinstated even if the cost ceiling subsequently increases by year-end. No ceiling test write-down was recorded for the six months ended December 31, 2005.

Calpine followed the successful efforts method of accounting for oil and natural gas activities. Under the successful efforts method, lease acquisition costs and all development costs were capitalized. Exploratory drilling costs were capitalized until the results are determined. If proved reserves were not discovered, the exploratory drilling costs were expensed. Other exploratory costs were expensed as incurred. Interest costs related to financing major oil and natural gas projects in progress were capitalized until the projects were evaluated or until the projects were substantially complete and ready for their intended use if the projects were evaluated as successful. Calpine also capitalized internal costs directly identified with acquisition, exploration and development activities and did not include any costs related to production, general corporate overhead or similar activities. The provision for depreciation, depletion, and amortization was based on the capitalized costs as determined above, plus future abandonment costs net of salvage value, using the unit of production method with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

Calpine assessed the impairment for oil and natural gas properties on a field by field basis periodically (at least annually) to determine if impairment of such properties was necessary. Management utilized its year-end reserve report prepared by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc.,

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and related market factors to estimate the future cash flows for all proved developed (producing and non-producing) and proved undeveloped reserves. Property impairments occurred if a field discovered lower than anticipated reserves, reservoirs produced at a rate below original estimates or if commodity prices fell below a level that significantly affected anticipated future cash flows on the property. Proved oil and natural gas property values were reviewed when circumstances suggested the need for such a review and, if required, the proved properties were written down to their estimated fair market value based on proved reserves and other market factors. Unproved properties were reviewed quarterly to determine if there was impairment of the carrying value, with any such impairment charged to expense in the period. As a result of decreases in proved undeveloped reserves and proved developed non-producing reserves located in South Texas, in California and in the Gulf of Mexico, respectively, a non-cash impairment charge of approximately $202.1 million and $2.9 million was recorded for the years ended December 31, 2004 and 2003, respectively, in the combined statements of operations. The downward revisions of Calpine s estimates were based on the independent reservoir engineer s year-end reserve report, which reflected production results and drilling activity that occurred during 2004 and 2003 and used historical field level historical decline curves. Due to significant capital constraints by Calpine, drilling activity was minimized and correspondingly the estimate of proved reserves could not be supported through drilling success or future capital activity and the downward revision was required. In addition, under the successful efforts method of accounting for oil and natural gas properties, individual assets are grouped at the lowest level for which there are identifiable cash flows. With minimal drilling activity and the evaluation of cash flows at this level, proved reserves for South Texas and California fields and the Gulf of Mexico had to be revised downward at each individual field level. No impairment charge was recorded for the six months ended June 30, 2005 (predecessor).

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

Other Current Liabilities. Other current liabilities consist primarily of end of the period accruals for lease operating costs, capital expenditures, asset retirement obligations and bonuses for employees.

Income Taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities using the liability method in accordance with the provisions set forth in SFAS No. 109, Accounting for Income Taxes . Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Income taxes have been calculated for the Company based on the appropriate tax regulations since it will file a tax return for the six months ended December 31, 2005. Income taxes have also been calculated on net income of the domestic oil and natural gas business of Calpine as if a separate return for the six months ended June 30, 2005 and the years ended December 31, 2004, and 2003 had been filed. See additional information in Note 10.

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

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Executory Contracts. Calpine had commodity contracts executed by them that did not qualify as leases under Statement of Financial Accounting standards (SFAS) No. 13, Accounting for Leases or derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities as amended by SFAS 138 and SFAS 139 and interpreted by other related accounting literature. The contracts were classified as executory contracts, and as a result were accounted for on an accrual basis for the six months ended June 30, 2005 and the years ended December 31, 2004 and 2003. The Company had no contracts classified as executory contracts for the six months ended December 31, 2005.

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

It is the Company s policy to calculate and pay royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Royalties Payable on the Company s Consolidated/Combined Balance Sheet.

Imbalances. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At December 31, 2005 and 2004, imbalances were insignificant.

Derivative Instruments and Hedging Activities. The Company uses derivative instruments to manage market risks resulting from fluctuations in commodity prices of natural gas and crude oil. The Company periodically enters into derivative contracts, including price swaps or costless price collars, which may require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of natural gas or crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments.

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

At the inception of a derivative contract, the Company may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documents the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the

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derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses included in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately. We do not enter into derivative agreements for trading or other speculative purposes.

Insurance Program. CPN Insurance Corporation, a wholly owned captive insurance subsidiary of Calpine, charged Calpine premiums to insure worker s compensation, automobile liability, and general liability as well as all risk property insurance including business interruption. Accruals for casualty claims under the captive insurance program were recorded on a monthly basis, and were based upon the estimate of the total cost of the claims incurred during the policy period. Accruals for claims under the captive insurance program pertaining to property, including business interruption claims, were recorded on a claims-incurred basis. Claims were accrued on a gross basis before deductibles. The captive provided insurance coverage with limits up to $25 million per occurrence for property claims, including business interruption, and up to $500,000 per occurrence for casualty claims.

Subsequent to the acquisition, the Company undertook to obtain insurance coverage from third party providers.

Stock-Based Compensation. On January 1, 2003, Calpine prospectively adopted, and the combined financial statements for 2003 and 2004 and the six months ended June 30, 2005 are presented, the fair market value method of accounting for stock-based employee compensation pursuant to SFAS No. 123, Accounting for Stock-Based Compensation , as amended by SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure (SFAS No. 123). Expense amounts included in the combined historical financial statements for the years ended December 31, 2004 and 2003 and the six months ended June 30, 2005 are based on stock based compensation granted to employees by Calpine. Stock options were granted at an option price equal to the quoted market price at the date of the grant or award.

In determining our accounting policies, the Company has chosen to apply the intrinsic value method pursuant to Accounting Standards Board (APB) APB No. 25, Stock Issued to Employees (APB No. 25), effective July 1, 2005. Under APB No. 25, no compensation is recognized when the exercise price for options granted equals the fair value of the Company s common stock on the date of the grant. Accordingly, the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, permit the continued use of the method prescribed by APB No. 25 but require additional disclosures, including pro forma calculations of net income (loss) per share as if the fair value method of accounting prescribed by SFAS No. 123 had been applied.

As required by SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, which amended SFAS No. 123, the following table illustrates the effect on net income and income per share as if we had applied the fair value recognition provisions of SFAS No. 123 to stock-based compensation. During the six months ended December 31, 2005, there were 706,550 options granted with vesting periods ranging from the date of grant and up to three years that required consideration under the disclosure provisions of SFAS No. 123. The fair value of awards considered in the table below for the six months ended December 31, 2005 (successor) is the result of the vesting of stock based award grants during that period. See Note 12 for further information.

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Shown below is the pro forma effect on net income and earnings per share as if the fair value method had been applied to stock-based awards for the six months ended December 31, 2005 (in thousands, except for per share amounts):

	Successor Six Months Ended December 31, 2005 (In thousands, per share amounts)	
Net income, as reported	$	17,535
Add: stock-based compensation expense determined under fair value based method for all awards, net of tax		(630)
Net income, pro forma	$	16,905
Net income, as reported		
Basic	$	0.35
Diluted	$	0.35
Net income, pro forma		
Basic	$	0.34
Diluted	$	0.34

The fair value of stock options included in the pro forma results for the six months ended December 31, 2005 is not necessarily indicative of future effects on net income and cash flow.

The weighted average fair value at date of grant for options granted during the six months ended December 31, 2005 (successor) was $9.59 per share. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: (a) dividend yield of 0.00%; (b) average expected volatility 54.62%; (c) average risk-free interest rate of between 4.03% and 4.60%; and (d) expected life of 6.5 years.

Other Assets. Calpine purchased redeemable performance bonds related to plugging, abandonment, site restoration and compliance with environmental laws. At December 31, 2004, they had obtained surety bonds from a number of insurance and bonding institutions covering certain operations in the United States in the aggregate amount of approximately $7.4 million. The Company also purchases performance bonds related to plugging, abandonment, site restoration and compliance with environmental laws. At December 31, 2005, these amounts were approximately $0.2 million.

Asset Retirement Obligations. Calpine adopted SFAS No. 143, Accounting for Asset Retirement Obligations as of January 1, 2003. SFAS No. 143 required them to record the fair market value of a liability for an asset retirement obligation (ARO), net of salvage value, in the period in which it was incurred. Upon adoption of SFAS No. 143, a liability was recorded for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset and a cumulative effect of a change in accounting principle was recorded in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost. Subsequent to adoption, liabilities were required to be accreted to their present value each period and capitalized costs were depreciated over the estimated useful life of the related assets. This periodic accretion expense is recorded as depreciation, depletion and amortization in the consolidated/combined statement of operations. Upon settlement of the liability, the obligation is settled against its recorded amount and the resulting gain or loss is recorded in the financial statements.

Asset Impairments. The carrying values of long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These events

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include changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment. When an event occurs, we evaluate the recoverability of our carrying value based on the long-lived asset s ability to generate future cash flows on an undiscounted basis. If an impairment is indicated or if we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair market value, less costs to sell. Our fair market value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors. We also reclassify the assets as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have any continuing involvement in the cash flows of those assets after they are sold. For assets held and used, the asset is written down to its realizable value if estimated future undiscounted cash flows attributable to the asset is less than recorded value of that asset. The impairment recorded is based on a comparison of discounted estimated future net cash flows to the net carrying value of the related asset.

New Accounting Pronouncements Not Yet Adopted

SFAS No. 123-R. In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123-R. This Statement revises SFAS No. 123 and supersedes APB No. 25 and its related implementation guidance. This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the fair market value of the award on the date of grant (with limited exceptions), which must be recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). The statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options, or other equity instruments or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity s shares or other equity instruments or (b) that require or may require settlement by issuing the entity s equity shares or other equity instruments.

The statement requires the accounting for any excess tax benefits to be consistent with the existing guidance under SFAS No. 123, which provides a two-transaction model summarized as follows:

- If settlement of an award creates a tax deduction that exceeds compensation cost, the additional tax benefit would be recorded as a contribution to paid-in-capital.

- If the compensation cost exceeds the actual tax deduction, the write-off of the unrealized excess tax benefits would first reduce any available paid-in capital arising from prior excess tax benefits, and any remaining amount would be charged against the tax provision in the income statement.

The statement also amends SFAS No. 95, Statement of Cash Flows, to require that excess tax benefits be reported as a financing cash inflow rather than as an operating cash inflow. However, the statement does not change the accounting guidance for share-based payment transactions with parties other than employees provided in SFAS No. 123 as originally issued and EITF Issue No. 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services . Further, this statement does not address the accounting for employee share ownership plans, which are subject to AICPA Statement of Position 93-6, Employers Accounting for Employee Stock Ownership Plans .

The statement applies to all awards granted, modified, repurchased, or cancelled after January 1, 2006, and to the unvested portion of all awards granted prior to that date. Public entities that used the fair market value method for either recognition or disclosure under SFAS No. 123 may adopt this Statement using a modified version of prospective application (modified prospective application). Under modified prospective application, compensation cost for the portion of awards for which the employee s requisite service has not been rendered that are outstanding as of January 1, 2006 must be recognized as the requisite service is rendered on or after that date. The compensation cost for that portion of awards shall be based on the original fair market value of those

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awards on the date of grant as calculated for recognition under SFAS No. 123. The compensation cost for those earlier awards shall be attributed to periods beginning on or after January 1, 2006 using the attribution method that was used under SFAS No. 123. Furthermore, the method of recognizing forfeitures must now be based on an estimated forfeiture rate and can no longer be based on forfeitures as they occur.

The adoption of SFAS No. 123-R is not expected to have a material impact on the Company s consolidated financial position, results of operations or cash flows.

Accounting Changes and Error Corrections. In May 2005 the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 (SFAS 154) , which changes the requirements for the accounting for and the reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed.

APB 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. When it is practicable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, SFAS 154 requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the balance sheet) for that period rather than being reported in the statement of operations. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, this Statement requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable.

This Statement defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. This Statement also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error.

SFAS 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. This Statement carries forward without change the guidance contained APB 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS 154 also carries forward the guidance in APB 20 requiring justification of a change in accounting principle on the basis of preferability.

SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Early adoption is permitted for accounting changes and corrections of errors made in fiscal years beginning after the date SFAS 154 is issued. SFAS 154 does not change the transition provisions of any existing accounting pronouncements, including those that are in a transition phase as of the effective date of SFAS 154. This Statement is not expected to impact the Company s consolidated financial position or results of operations.

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Exchanges of Nonmonetary Assets. In January 2005, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29. This statement, which addresses the measurement of exchanges of nonmonetary assets, is effective prospectively for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The adoption of this statement did not impact the Company s consolidated financial position or results of operations.

Accounting for Certain Hybrid Financial Instruments. In February 2006 , the FASB issued SFAS No. 155, Accounting for Certain Hybrid Instruments-an amendment of FASB Statements 133 and 140, which is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. The statement improves financial reporting by eliminating the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. The Statement also improves financial reporting by allowing a preparer to elect fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event, on an instrument by-instrument basis, in cases in which a derivative would otherwise have to bifurcated, if the holder elects to account for the whole instrument on a fair value basis. The Company is currently evaluating the impact, if any, of this Statement on the combined financial statements.

(4) Accounts Receivable

Accounts receivable consisted of the following:

	Successor December 31, 2005	Predecessor December 31, 2004
	(In thousands)	
Natural gas, NGLs and oil revenue sales	$ 35,066	$ 7,190
Joint interest billings	3,382	3,580
Short-term receivable for royalty recoupment	1,603	1,603
Total	40,051	12,373
Less: allowance for doubtful accounts		(570)
Accounts receivable, net	$ 40,051	$ 11,803

(5) Property, Plant and Equipment, Property Acquisitions and Capitalized Interest

Oil and Natural Gas Properties.

The Company s total oil and natural gas properties consist of the following:

	Successor December 31, 2005	Predecessor December 31, 2004
	(In thousands)	
Proved properties (1)	$ 951,968	$ 1,095,022
Unproved properties (1)	21,217	10,538
Total	973,185	1,105,560
Less: accumulated depreciation, depletion and amortization	(40,029)	(500,722)
Net capitalized costs	$ 933,156	$ 604,838

(1) Full cost method (successor) and successful efforts method (predecessor)

Included in the Company s oil and gas properties is asset retirement obligations of $9.1 million and $6.6 million at December 31, 2005 and 2004, respectively, including additions of $9.2 million and $0.7 million for the six months ended December 31, 2005 and the year ended December 31, 2004, respectively (successor). See Note 9.

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At December 31, 2005, the Company excluded the following capitalized costs from depletion, depreciation and amortization (In thousands):

Onshore:	
Development cost	4,589
Exploration cost	6,144
Acquisition cost of undeveloped acreage	19,684
Capitalized interest	555
Total	30,972
Offshore:	
Development cost	
Exploration cost	5,095
Acquisition cost of undeveloped acreage	950
Capitalized interest	27
Total	6,072
Total excluded costs from depreciation, depletion and amortization	37,044

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $21.2 million and development and exploration costs of $15.8 million will be included in depreciation, depletion and amortization within five years and one year, respectively. At December 31, 2005, the onshore development costs related to wells that are drilling and expected to be completed in 2006. Of the total offshore exploration costs of $5.1 million, all but $2.6 million related to wells currently being drilled and expected to be completed and on production in 2006. The $2.6 million in costs related to a well that was drilled, production casing set, successfully tested and is awaiting platform installation.

Property Acquisitions. Through our participation in a joint venture in the Gulf of Mexico in August 2005, we have acquired a 25% non-operating working interest in a joint venture in two offshore blocks, Main Pass Block 118 and Main Pass Block 117 for a total cost of $6.6 million. This occurred during the six months ended December 31, 2005.

In the State Waters of Texas operating area in August 2005, we acquired a 7% non-operating working interest and a 5% net revenue interest in the TB-2 prospect and a 34% operating working interest and a 24% net revenue interest in the Half Moon Shoal prospect in Galveston Bay for $0.1 million and $0.9 million, respectively.

We acquired in October 2005 a 25% working interest for a total of $5.5 million in certain oil and gas leases covering lands in Kleberg and Kenedy counties, Texas, known as the Peach Prospect.

Other Property and Equipment. Other property and equipment at December 31, 2005 (successor) and 2004 (predecessor) of $2.9 million and $6.0 million, respectively, net of accumulated depreciation, depletion and amortization of $0.1 million and $4.3 million, respectively, consists primarily of a gas gathering system and compressor station in California. For the six months ended December 31, 2005 (successor), the six months ended June 30, 2005 and the years ended December 31, 2004 and 2003 (predecessor), depreciation expense for these assets was $0.5 million, $0.6 million, $1.5 million and $0.4 million, respectively. The Company recorded additional depreciation expense for other equipment, which includes furniture and fixtures of $0.1 million, $0.4 million, $0.8 million and $1.0 million for these same periods.

Capitalized Interest. The Company capitalizes interest on capital invested in projects during the advanced stages of development and the drilling period in accordance with SFAS No. 34, Capitalization of Interest Cost, (SFAS No. 34) as amended by SFAS No. 58, Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of FASB Statement No. 34). Upon commencement of production, capitalized interest, as a component of the total cost of a field is depleted.

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(6) Other Assets

At December 31, 2005, deferred loan fees were $4.6 million and are being amortized on a straight-line basis over the term of the long-term debt ranging from four to five years. Total amortization expense for deferred loan fees was $0.6 million for the six months ended December 31, 2005.

Calpine had purchased redeemable performance bonds related to plugging, abandonment, site restoration and compliance with environmental laws. At December 31, 2004, Calpine had obtained surety bonds from a number of insurance and bonding institutions covering certain operations in the United States in the aggregate amount of approximately $7.4 million. At December 31, 2005, the Company had approximately $0.2 million in redeemable performance bonds related to plugging, abandonment, site restoration and compliance with environmental laws.

(7) Commodity Hedging Contracts and Other Derivatives

As of December 31, 2005, the Company had the following commodity related derivative instruments outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Natural Notional Annual Volume MMBtu	Average Fixed Price per MMBtu	Total of Proved Natural Gas Production Hedged(1)	Fair Value Gain/ (Loss) (In thousands)
2006	Swap	Cash flow	45,000	16,425,000	$ 7.923	46%	$ (29,958)
2007	Swap	Cash flow	36,300	13,249,500	$ 7.617	33%	(25,817)
2008	Swap	Cash flow	30,876	11,300,616	$ 7.297	27%	(16,931)
2009	Swap	Cash flow	26,141	9,541,465	$ 6.989	26%	(10,230)
Total				50,516,581			$ (82,936)

(1) Estimated based on net gas reserves presented in the December 31, 2005 Netherland, Sewell & Associates, Inc. reserve report.

The Company s current cash flow hedge positions are with counterparties that are lenders in our credit facilities. This allows us to securitize any margin obligation resulting from a negative change in the fair value of the derivative contracts in connection with our credit obligations and eliminate the need for independent collateral postings. As of December 31, 2005, we had no deposits for collateral.

The following table sets forth the results of third party hedging transactions for the respective period for the statement of operations:

	Successor Six Months Ended December 31, 2005
Natural gas	
Quantity settled (MMBtu)	7,956,000
Increase (Decrease) in Natural Gas Sales Revenue	$ (16,575,709)

Based on commodity prices as of December 31, 2005, the Company expects to reclassify losses of $30.0 million to earnings from the balance in Accumulated Other Comprehensive Loss during the next twelve months. At December 31, 2005, the Company had derivative liabilities of $82.9 million of which $30.0 million are included in Derivative instrument liability-short term on the Consolidated Balance Sheet. The Company also had

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a Derivative instrument asset-short-term of $1.1 million on the Consolidated Balance Sheet at December 31, 2005.

The derivative assets and liabilities related to commodities represent the fair value of the hedge positions based on counterparty quotes as of December 31, 2005. Hedging activities related to cash settlements on commodities decreased revenues $16.6 million for the six months ended December 31, 2005 (successor). There were no cash settlements on commodities for the six months ended June 30, 2005 (predecessor) and the years ended December 31, 2004 and 2003 (predecessor).

Gains and losses related to ineffectiveness and derivative instruments not designated as hedging instruments are included in Other Income (Expense). There was no ineffectiveness pertaining to cash-flow hedges recorded for the six months ended December 31, 2005 (successor). There were no gains related to derivative instruments not designated as hedged instruments for the six months ended June 30, 2005 (predecessor) and for the years ended December 31, 2004 and 2003 (predecessor) as no derivative instruments existed.

In December 2005, we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for a portion of our expected production in 2006. If the floating price each month at the settlement point is greater than the ceiling price, we pay the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pays us an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month.

The following table describes our open costless collar transactions at December 31, 2005 by associated notional volumes and contracted ceiling and floor prices at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMbtu	Total of Natural Notional Annual Volume MMbtu	Average Floor Price per MMbtu	Average Ceiling Price per MMbtu	Fair Value Gain/(Loss) (In thousands)
2006	Costless Collar	Cash flow	10,000	3,650,000	$ 8.825	$ 14.000	$ 1,110

The total of proved natural gas production hedged in 2006 for the costless collars is approximately 10% based on the December 31, 2005 reserve report prepared by Netherland, Sewell & Associates, Inc.

(8) Long-Term Debt

Long-term debt consisted of the following:

	Successor December 31, 2005	Predecessor December 31, 2004
	(In thousands)	
Note payable under a revolving credit agreement, due on July 7, 2009	$ 165,000	$
Note payable under term loan, due July 7, 2010	75,000	
Less: current portion		
Total Notes Payable	$ 240,000	$

Senior Secured Revolving Line of Credit. BNP Paribas, in July 2005 provided the Company with a senior secured revolving line of credit concurrent with the acquisition in the amount of up to $400 million. This

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revolving line of credit was syndicated to a group of lenders on September 27, 2005. Availability under the revolver is restricted to the borrowing base (as described below), and initially was $275 million and was reset to $325 million (the borrowing base), upon amendment, as a result of the hedges put in place in July 2005 and the favorable effects of our subsequent equity offering through which the Company received $70 million of funds (net of transaction fees). In July 2005, the Company repaid $60 million of the $225 million in original borrowings on the Revolver. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements. Amounts outstanding under the revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00%. Such margins will fluctuate based on the utilization of the facility. As of December 31, 2005, the weighted average interest rate on the Company s revolving line of credit was 5.88%. Borrowings under the revolver are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the PV-10 value, a guaranty by all of the Company s domestic subsidiaries, a pledge of 100% of the stock of domestic subsidiaries, and a lien on cash securing the Calpine gas purchase and sale contracts. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2005. All amounts drawn under the revolver are due and payable on July 7, 2009.

Second Lien Term Loan. BNP Paribas, in July 2005, also provided the Company with a second lien term loan concurrent with the acquisition of Calpine s domestic oil and natural gas business, in the amount of $100 million. On September 27, 2005, the Company repaid $25 million of borrowings on the term loan, reducing the balance to $75 million and syndicated such loan to a group of lenders including BNP Paribas. Borrowings under the term loan initially bore interest at LIBOR plus 5.00%. As a result of the hedges put in place in July 2005 and the favorable effects of the Company s private equity placement, (see Note 13), the interest rate for the second lien term loan was reduced to LIBOR plus 4.00%. As of December 31, 2005, the weighted average interest rate on the company s second lien term loan was 8.38%. The loan is collateralized by second priority liens on substantially all of our assets. The Company is subject to the financial covenants of a minimum asset coverage ratio of not less than 1.50 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. In addition, the Company will be subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2005. The revised principal balance is due and payable on July 7, 2010.

Aggregate maturities required on long-term debt at December 31, 2005 due in future years are as follows (in thousands):

2006	$	
2007		
2008		
2009		165,000
2010		75,000
Thereafter		
Total	$	240,000

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(9) Asset Retirement Obligations

Activity related to the Company s ARO during the years ended December 31, 2005 and 2004 is as follows :

	Successor Six Months Ended December 31, 2005	Predecessor Year Ended December 31, 2004
	(In thousands)	
ARO as of beginning of period	$ 8,789	$ 9,335
Liabilities incurred during period	447	679
Liabilities settled during period	(121)	(1,517)
Accretion expense	352	1,153
Other Adjustments		
Balance of ARO as of end of period	$ 9,467	$ 9,650

Of the total ARO, approximately $0.4 million and $1.3 million are classified as a current liability at December 31, 2005 and 2004, respectively. For the six months ended December 31, 2005 (successor) and the years ended December 31, 2004 and 2003 (predecessor) the Company recognized depreciation expense related to its ARO of approximately $0.4 million, $1.5 million and $0.9 million, respectively. As a result of the adoption of SFAS No. 143 on January 1, 2003, Calpine recorded a $0.2 million increase in the net capitalized cost of its oil and natural gas properties as the cumulative effect of the change in accounting principle (net of related income tax benefit).

(10) Provision for Income Taxes and Other Taxes

Under SFAS No. 109, Accounting for Income Taxes, deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse.

At December 31, 2005, the Company had a deferred tax asset related to net operating loss carryforwards of approximately $0.6 million. The federal and state net operating loss carryforwards available are subject to limitations on their annual usage. Realization of the deferred tax assets and net operating loss carryforwards is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced. There is no valuation allowance recorded on this deferred tax asset as the Company believes it is more likely than not that the asset will be utilized.

The Company s income tax expense (benefit) from continuing operations consists of the following:

	Successor	Predecessor		
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
Current:		(in thousands)		
Federal	$	$ 7,556	$ 25,452	$ 21,645
State		1,067	3,670	2,882
		8,623	29,122	24,527

Deferred:				
Federal	10,139	2,519	(68,078)	17,657
State	1,398	354	(9,569)	2,324
	11,537	2,873	(77,647)	19,981
Total income tax expense (benefit)	$ 11,537	$ 11,496	$ (48,525)	$ 44,508

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

	Successor Six Months Ended		Six Months Ended		Predecessor Year Ended		Year Ended	
	December 31, 2005 (In thousands)	December 31, 2005 (%)	June 30, 2005 (In thousands)	June 30, 2005 (%)	December 31, 2004 (In thousands)	December 31, 2004 (%)	December 31, 2003 (In thousands)	December 31, 2003 (%)
U.S. statutory rate	$ 10,175	35.0%	$ 10,562	35.0%	$ (44,576)	35.0%	$ 38,985	35%
State income/franchise tax, net of federal benefit	909	3.1%	924	3.1%	(3,896)	3.1%	3,384	3%
Transaction costs not deductible	466	1.6%						
Permanent differences and other	(13)		10	0.0%	(53)	0.0%	2,139	2%
Total tax expense (benefit)	$ 11,537	39.7%	$ 11,496	38.1%	$ (48,525)	38.1%	$ 44,508	40%

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

The components of deferred taxes are as follows (in thousands):

Year Ended December 31,	Successor 2005	Predecessor 2004
Deferred tax assets		
Accrued liabilities not currently deductible	$ 1,614	$ 561
AMT tax credit carryforward		146
Other reserves not currently deductible	276	
Hedge activity	31,093	
Net operating loss carryforward	608	6,426
Total gross deferred tax assets	33,591	7,133
Oil and Gas Basis Differences	(14,007)	(152,287)
Depreciation	(28)	(555)
Total gross deferred tax liabilities	(14,035)	(152,842)
Net deferred tax assets (liabilities)	$ 19,556	$ (145,709)

(11) Commitments & Contingencies

The Company is party to various litigation matters arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters

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will have a material adverse effect on the Company s financial position, results of operation or cash flows. As of December 31, 2005 and 2004, a reserve for legal fees was recorded in other current liabilities on the Consolidated/Combined Balance Sheets in the amount of $0.4 million and $0.1 million, respectively.

Calpine Bankruptcy

Calpine and certain of its subsidiaries (collectively, the Debtors) filed for protection under the federal bankruptcy laws in the Southern District of New York on December 20, 2005. The Company is not presently a party to any pending litigation in connection with this bankruptcy, although counsel has filed a notice of appearance on our behalf so we may effectively monitor the proceedings. Calpine Energy Services, L.P. has continued to make the required deposits into Rosetta s margin account and to timely pay for production it purchases from the Company s subsidiaries under various supply agreements. Calpine and certain of its subsidiaries have generally continued to provide services desired by the Company under the Transition Services Agreement and Calpine Producer Services, L.P. generally is performing its obligations under the Marketing and Services Agreement with us.

There remains the possibility, however, that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the Purchase and Sale Agreement, dated July 7, 2005 by and among Calpine, the Company and various other parties signatories thereto (the Purchase Agreement) including unasserted claims and assessments with respect to (i) the still pending final closing under the Purchase Agreement and the amounts that will be payable in connection therewith, (ii) whether or not Calpine and its affiliated debtors will, in fact, perform their remaining obligations in connection with the final closing, and (iii) the ultimate disposition of certain properties (and related royalty revenues) for which third party consents to transfer had not been obtained at the time of the original closing under the Purchase Agreement. While the Company remains hopeful that it will be able to work cooperatively with Calpine so as to accomplish the delivery by Calpine of record legal title including all ancillary ministerial and administrative corrections for all non-consent properties, as well as the curative corrections for all properties which the Company paid for, all of the same being covered by the further assurances provision of the parties definitive agreements, the timing and exact details of how, when and if this will be able to be accomplished continue to remain uncertain at this early stage of Calpine s bankruptcy. The Company s management continues to believe that it is unlikely that any challenges by the Calpine debtors or their creditors to the fairness of this acquisition would be successful. At the present time, there is no pending or overtly threatened litigation in this regard. However, in the future there may be possible unasserted claims and assessments, seeking to challenge some aspect of the acquisition.

Deanne Lounsberry Duhon, et al. v. Ensearch Exploration, Inc., et al.

This lawsuit is a retained liability by Calpine. On September 10, 2004, Apache Corporation (Apache) filed a cross-claim and third party demand in the above listed matter and has named Calpine Natural Gas and Agricultural Methane in this suit. A dispute has arisen as to the division of royalties between certain groups. The plaintiffs are seeking the forfeiture from Apache of the working interest income stream from the proceeds of the production of the well in various producing intervals. Apache is seeking claims for contribution and indemnifying in the event Apache is found liable. RROLP and Agricultural Methane are currently reviewing these allegations. It is the Company s understanding that this matter has been settled for an immaterial amount.

Arbitration between Calpine Corp./RROLP and Pogo Producing Company

This is a retained liability by the predecessor. On September 1, 2004, Calpine and RROLP (collectively Calpine), sold its New Mexico oil and natural gas assets to Pogo Producing Company (Pogo). During the course of the sale, Pogo made a title defect claim (valued at approximately $1.9 million) claiming that certain leases subject to the sale had expired because of lack of production. Although Calpine has undertaken to resolve this matter by obtaining ratifications of a majority of the questionable leases, Pogo has been unwilling to compromise its claim for the title defect value and has invoked the arbitration provisions of the underlying

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purchase and sale agreement. It is the Company s understanding that Calpine has cured 85-90% of alleged title defects. The arbitration is subject to Calpine s stay and, therefore is on hold. This is a retained liability by Calpine and it is management s belief that this will have no financial impact to the Company.

Claim for Indemnification by Bill Barrett Corporation

It is the Company s understanding that this matter has been settled by Bill Barrett. Calpine still has potential contractual indemnification subject to stay. This is a retained liability by Calpine and it is management s belief that this will have no financial impact to the Company.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. The Company performed an environmental remediation study for three sites in California and correspondingly, recorded a liability, which at December 31, 2005 and 2004 was $0.7 million and $0.7 million, respectively. We do not expect that the outcome of our environmental matters discussed above will have a material adverse effect on the Company s financial position, results of operations or cash flows.

Participation in a Regional Carbon Sequestration Partnership

In accordance with its obligations to Calpine under the parties transition services agreement, the Company has made preliminary preparations in connection with its cooperating with Calpine to participate in a joint study in connection with the U.S. Department of Energy s (DOE) Regional Carbon Sequestration Partnership program (WESTCARB) with the California Energy Commission and the University of California, Lawrence Berkeley Laboratory. The Company has been selected by the DOE for this project. Under WESTCARB, the Company would be required to drill a carbon injection well, recondition an idle well for use as an observation well and provide WESTCARB with certain proprietary well data and technical assistance related to the evaluation and injection of carbon dioxide into a suitable natural gas reservoir in the Sacramento Basin. The Company s maximum contribution to WESTCARB is $1.0 million and will be limited to 20% of the total contributions to the project. The Company will not have any obligation under the WESTCARB project until it has entered into an acceptable contract and the project has obtained proper and necessary local, state and federal regulatory approvals, land use authorizations, and third party property rights. No accrual was recorded at December 31, 2005 as the study is still in the preliminary stage.

Lease Obligations and Other Commitments

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $ 0.6 million for the six months ended December 31, 2005 (successor). For the six months ended June 30, 2005 (predecessor) and for the year ended December 31, 2004 the expense for office lease and building maintenance was allocated by Calpine Corporation on a square footage basis coinciding with the move to Calpine Center in 2004. The expense allocated was $1.1 million and $1.6 million, respectively, for the six months ended June 30, 2005 and the year ended December 31, 2004. The rent expense was $1.7 million for the year ended December 31, 2003.

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Future minimum annual rental commitments under non-cancelable leases at December 31, 2005 are as follows (In thousands):

2006	$ 1,924
2007	1,916
2008	1,975
2009	2,032
2010	1,866
Thereafter	5,892
	$ 15,605

The Company has drilling rig commitments of $17.1 million and $1.6 million for 2006 and 2007, respectively.

(12) Employee Benefit Plans

Successor

2005 Long-Term Incentive Plan

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

Stock Options

The following table summarizes information concerning outstanding and exercisable options held by the Company s employees at December 31, 2005:

	Shares	Price Per Share
Outstanding July 1, 2005		
Granted from July 7, 2005 to December 31, 2005	716,550	$ 16.28
Exercised		
Canceled	(10,000)	16.00
Outstanding December 31, 2005	706,550	$ 16.28
Options exercisable:		
December 31, 2005	199,137	$ 16.25

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Range of Exercise Prices	Number of Options Outstanding	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Exercise Price
\$16.00 \$ 16.00	603,550	9.52	\$ 16.00	173,387	\$ 16.00
\$16.75 \$ 16.75	24,500	9.61	\$ 16.75	6,125	\$ 16.75
\$18.00 \$ 18.00	28,500	9.74	\$ 18.00	7,125	\$ 18.00
\$18.10 \$ 18.10	6,000	9.87	\$ 18.10	1,500	\$ 18.10
\$18.25 \$ 18.25	7,500	9.71	\$ 18.25	1,875	\$ 18.25
\$18.50 \$ 18.50	26,000	9.69	\$ 18.50	6,500	\$ 18.50
\$18.75 \$ 18.75	2,000	9.81	\$ 18.75	500	\$ 18.75
\$19.00 \$19.00	8,500	9.74	\$ 19.00	2,125	\$ 19.00
\$16.00 \$19.00	706,550	9.55	\$ 16.28	199,137	\$ 16.25

Restricted Stock

The Company issued 585,400 net shares of restricted stock in 2005. The restrictions on approximately 53% of the restricted stock lapse over a three year period at a rate of 25% on the first anniversary, 25% on the second anniversary and 50% on the third anniversary. The restrictions on the remaining awards, with the exception of 3,500 shares which vested in August 2005, lapsed on the day after Rosetta s effective date of their recently completed initial public offering in February 2006. The weighted average grant-date fair value of restricted stock granted for the six months ended December 31, 2005 was approximately \$17.83 per share. Related compensation expense for restricted stock of approximately \$4.2 million was recognized for the six months ended December 31, 2005.

Predecessor

Retirement Savings Plan

Calpine, has a defined contribution savings plan, under Section 401(a) and 501(a) of the Internal Revenue Code, in which the Calpine s employees were eligible to participate. The plan provided for tax deferred salary deductions and after-tax employee contributions. Employees were immediately eligible upon hire. Contributions included employee salary deferral contributions and employer profit-sharing contributions made entirely in cash of 4% of employees salaries, with employer contributions capped at \$8,200 per year for 2004 and \$8,400 per year for 2005. Employer profit-sharing contributions in 2004 and 2003 totaled \$0.4 million and \$0.3 million, respectively. There were no employer profit-sharing contributions for the six months ended June 30, 2005.

2000 Employee Stock Purchase Plan

Calpine adopted the 2000 Employee Stock Purchase Plan (ESPP) in May 2000. Calpine s eligible employees could in the aggregate purchase up to 28,000,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases were limited to either a maximum value of \$25,000 per calendar year based on the IRS Code Section 423 limitation or limited to 2,400 shares per purchase interval. Shares were purchased on May 31 and November 30 of each year until termination of the plan on May 31, 2010. Under the ESPP, 91,809 and 63,585 shares were issued to Calpine s employees at a weighted average fair market value of \$3.26 and \$3.69 per share in 2004 and 2003, respectively. In the six months ended June 30, 2005 under the ESPP, 36,817 shares were issued to Calpine s employees at a weighted average fair market value of \$2.53 per share. The purchase price was 85% of the lower of (i) the fair market value of the common stock on the participant s entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date. The purchase price discount was significant enough to cause the ESPP to be considered compensatory under SFAS No. 123. As a result, the ESPP was accounted for as stock-based compensation in accordance with SFAS No. 123 for 2003 and 2004 during which \$0.1 million and \$0.1 million of compensation expense was recognized, respectively. For the six months ended June 30, 2005, there was \$0.2 million of compensation expense recorded under the ESPP

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plan. See Note 3 for information related to the Calpine s accounting for stock-based compensation expense. Prior to the adoption of SFAS No. 123 on January 1, 2003, Calpine accounted for the ESPP under APB Opinion No. 25, under which the ESPP was considered a non-compensatory plan.

1996 Stock Incentive Plan

Calpine adopted the 1996 Stock Incentive Plan (SIP) in September 1996 in which certain of the Company s employees were eligible to participate. The SIP succeeded Calpine s previously adopted stock option program. Prior to the adoption of SFAS No. 123 on January 1, 2003, (see Note 3), Calpine accounted for the SIP under APB Opinion No. 25, under which no compensation cost was recognized through December 31, 2002.

For the six months ended June 30, 2005 and the years ended December 31, 2004 and 2003, Calpine granted options to the Company s employees to purchase 37,500, 292,850 and 218,550 shares of common stock, respectively. Over the life of the SIP, options exercised equaled 48,552 leaving 754,284 granted and not yet exercised. Under the SIP, the option exercise price generally equaled the stock s fair market value on date of grant. The SIP options generally vested ratably over four years and expired after 10 years.

	Outstanding Number of Options	Weighted Average Exercise Price
Outstanding January 1, 2003	318,384	$ 18.016
Granted	218,500	$ 3.987
Exercised		
Canceled		
Outstanding December 31, 2003	536,884	$ 12.306
Granted	292,850	5.551
Exercised		
Canceled	(63,618)	14.537
Outstanding December 31, 2004	766,116	$ 9.539
Granted	37,500	3.320
Exercised		
Canceled	(49,332)	5.702
Outstanding June 30, 2005	754,284	$ 9.481
Options exercisable:		
December 31, 2003	174,521	$ 12.306
December 31, 2004	265,942	$ 15.678
June 30, 2005	403,885	$ 13.422

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The following table summarizes information concerning outstanding and exercisable Calpine options held by the Company s employees at June 30, 2005:

Range of Exercise Prices	Number of Options Outstanding	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Exercise Price
$2.650 $ 3.840	36,750	6.70	$ 3.318	250	$ 3.086
$3.980 $ 3.980	195,500	7.52	$ 3.980	101,500	$ 3.980
$4.060 $ 5.240	60,600	7.18	$ 5.234	31,850	$ 5.232
$5.560 $ 5.560	249,000	8.66	$ 5.560	68,251	$ 5.560
$6.510 $ 6.830	100	6.83	$ 6.670	100	$ 6.670
$7.640 $ 7.640	77,428	6.63	$ 7.640	67,028	$ 7.640
$7.750 $28.270	76,515	4.08	$ 15.620	76,515	$ 15.620
$30.850 $48.625	58,241	5.65	$ 47.293	58,241	$ 47.293
$51.400 $51.400	100	5.24	$ 48.625	100	$ 48.625
$54.030 $54.030	50	5.75	$ 54.030	50	$ 54.030
$ 2.650 $54.030	754,284	7.24	$ 9.481	403,885	$ 13.422

The range of fair market values of Calpine s stock options granted for the six months ended June 30, 2005 and the years ended 2004 and 2003 were as follows, based on varying historical stock option exercise patterns by different levels of the Company s employees: $1.27 for the six months ended June 30, 2005, $1.99 to $4.56 for 2004 and $1.52-$4.14 for 2003 on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: expected dividend yields of 0%, expected volatility of 58% for the six months ended June 30, 2005, 77%-98% for 2004 and 76%-113% for 2003, risk-free interest rates of 3.62% for the six months ended June 30, 2005, 2.57%-4.02% for 2004 and 1.76%-4.04% for 2003, and expected option terms of 2.5 years for the six months ended June 30, 2005, 3-9.5 years for 2004 and 1.5-9.5 years for 2003.

(13) Earnings Per Share

In July 2005, the Company was capitalized with fifty million shares of common stock, through a private placement of 45,312,500 shares of our common stock to qualified institutional buyers and non-U.S. persons in transactions exempt from registration under the Securities Act of 1933 and through an exempt transaction in connection with the acquisition. Additionally, we sold 4,687,500 shares of our common stock in an exempt transaction on July 14, 2005 for proceeds of $70 million (net of transaction costs) which we used to repay $60 million of debt under our new revolving credit facility with the remaining amount used to fund unspecified operating costs and general and administrative costs of oil and natural gas operations. In accordance with Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 98, this capitalization has been retroactively reflected for purposes of calculating earnings per share (EPS) for all periods presented in the accompanying statements of operations.

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

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The following is a calculation of basic and diluted weighted average shares outstanding (in thousands):

	Successor	Predecessor		
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
Shares basic	50,003	50,000	50,000	50,000
Dilution effect of stock option and awards at end of period	186	160		160
Shares diluted	50,189	50,160	50,000	50,160
Stock awards and shares excluded from diluted earnings per share due to anti-dilutive effect			160	

(14) Significant Customer

In 2004 and 2003, Calpine had two significant customers, both Calpine affiliates, which accounted for 76.7% and 79.8%, respectively of Calpine s annual combined revenues which is reflected as oil and natural gas to affiliates: Calpine Energy Services (CES) and Calpine Producer Services, L.P. (CPS). For the six months ended December 31, 2005 and June 30, 2005, CES and CPS also accounted for 80.2% and 83.2%, respectively of the Company s annual consolidated revenue and is reflected in oil and natural gas sales. See Note 17 for a discussion of the Company s activity with CES and CPS.

For the six months ended December 31, 2005 and June 30, 2005 and the years ended 2004 and 2003, revenues from sales to CES were $49.1 million and $82.0 million, $190.2 million and $223.5 million, respectively. Additionally, receivables from CES at December 31, 2004 were $21.1 million. There was no receivable from CES at December 31, 2005. Under the gas purchase and sale contract, CES is required to collateralize payments under the contract by daily margin payments into our collateral account, which are then settled at the end of the month. At December 31, 2005, the Company had $14.5 million in the margin account for December sales to CES which is included in other current liabilities on the Consolidated Balance Sheet.

We also entered into a marketing and services agreement with CPS in July 2005 for the period through June 30, 2007. The agreement covers all our current and future production during the term of the agreement. Additionally, CPS provides services related to the sale of our production including nominating, scheduling, balancing and other customary marketing services and assists us with volume reconciliation, well connections, credit review, training, severance and other similar taxes, royalty support documentation, contract administration, billing, collateral management and other administrative functions. All CPS activities are performed as agent and on our behalf, and under our control and direction. The fee payable by us under the agreement is based on net proceeds of all commodity sales multiplied by 0.75%. For the six months ended December 31, 2005, the fee was approximately $1.4 million. We can request a reduction in the fee if our volume increases to 130,000 MMBtu per day and 190,000 MMBtu per day to 0.625% and 0.50% respectively. The service agreement provides that all contracts, agreements, collateral and funds related to the marketing and sales activity be contracted directly with us or our designee, and paid directly to us.

(15) Operating Segments

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with SFAS No. 131, Disclosure About Segments of an Enterprise and Related Information. See below for information by geographic location.

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Geographic Area Information

During the six months ended December 31, 2005 (successor) and June 30, 2005 and the years ended December 31, 2004 and 2003 (predecessor), the Company owned oil and natural gas interests in eight main geographic areas in the United States. Geographic revenue, excluding the effects of hedging, and property, plant and equipment information is based on physical location of the assets at the end of each period.

	Successor Six Months Ended December 31, 2005		Predecessor Six Months Ended June 30, 2005		Year Ended December 31, 2004		Year Ended December 31, 2003	
	Total Oil & Gas Revenue	Total Assets (1)	Total Oil & Gas Revenue	Total Assets, Net	Total Oil & Gas Revenue	Total Assets, Net	Total Oil & Gas Revenue	Total Assets, Net
	(In thousands)				(In thousands)			
California	$ 48,138	$ 386,513	$ 43,385	$ 153,378	$ 108,320	$ 155,707	$ 148,692	$ 156,119
Lobo	39,062	368,276	26,474	347,319	62,417	354,450	76,926	572,268
Perdido	14,675	25,983	12,380	23,696	21,200	19,756	4,054	11,550
State Waters	6,761	12,067	2,345	4,854	88	676	114	4
Other Onshore	9,364	75,798	7,662	30,052	13,734	29,982	14,533	30,143
Gulf of Mexico	9,921	77,416	10,542	35,793	40,195	35,340	31,375	50,904
Rocky Mountains	338	21,224	161	7,273	284	5,792	194	449
Mid-Continent	1,309	5,969	842	3,149	1,549	3,135	3,806	6,109
Other	112	2,851	40	1,327		1,682		2,844
	$ 129,680	$ 976,097	$ 103,831	$ 606,841	$ 247,787	$ 606,520	$ 279,694	$ 830,390

(1) Total assets at December 31, 2005 are gross assets and not net of depreciation, depletion and amortization. Under the full cost method of accounting for oil and gas properties, depreciation, depletion and amortization is not allocated to properties.

(16) Discontinued Operations

On September 1, 2004, the Company completed the sale of its Rocky Mountain natural gas properties that were primarily concentrated in two geographic areas: the Colorado Piceance Basin and the New Mexico San Juan Basin. Together, these assets represented approximately 120 billion cubic feet equivalent (Bcfe) of proved natural gas reserves, producing approximately 16.3 million net cubic feet equivalent (MMcfe) per day of natural gas as of September 1, 2004. Under the terms of the agreement, Calpine received net cash proceeds of approximately $218.7 million, and recorded a pre-tax gain of approximately $103.7 million.

The tables below present significant components of the Company s income from discontinued operations for the years ended December 31, 2004 and 2003, respectively (in thousands):

	Predecessor Year Ended December 31, 2004	Year Ended December 31, 2003
Total revenue	$ 23,081	$ 26,193
Gain (loss) on disposal before taxes	103,707	(235)
Operating income from discontinued operations before taxes	7,823	7,408
Income from discontinued operations before taxes	111,530	7,173
Income tax provision	(43,090)	(2,768)

Income from discontinued operations, net of tax	$ 68,440	$ 4,405

At December 31, 2004, there were no assets of discontinued operations as the assets were sold in September 2004.

The Company allocates interest to discontinued operations in accordance with EITF Issue No. 87-24, Allocation of Interest to Discontinued Operations. The Company includes interest expense on debt that is required to be repaid as a result of a disposal transaction in discontinued operations. Additionally, other interest expense that cannot be attributed to other operations of the Company is allocated based on the ratio of net assets to be sold less debt that is required to be paid as a result of the disposal transaction to the sum of total net assets

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of the Company plus combined debt of the Company, excluding (a) debt of the discontinued operation that will be assumed by the buyer, (b) debt that is required to be paid as a result of the disposal transaction and (c) debt that can be directly attributed to other operations of the Company.

(17) Related Party Transactions

Successor

During the six months ended December 31, 2005, the Company purchased accounting contract services from a firm in which a principal partner is related to an officer of the Company. Total expenditures for these services in this period were $0.6 million.

Predecessor

The Company and certain of its affiliates have entered into various agreements with respect to the domestic oil and natural gas properties. These contracts were all cancelled at the date of acquisition of the oil and natural gas business by the Company. Following is a general description of each of the various agreements:

Agency Agreement. Calpine entered into a service agreement with CPS beginning April 1, 2003. The contract automatically renewed every year unless terminated by either party. CPS provided services related to Calpine s production, including marketing, contract administration, royalty and working interest owner issues, and receipt of payments. All activities performed by CPS were performed on behalf of the Calpine and under the Calpine s control and direction, in exchange for a fee for services rendered. Calpine dispensed all royalty payments when CPS provided accurate and timely details. Management fees of $0.9 million for the six months ended June 30, 2005 and $1.9 million and $2.9 million were recorded as Affiliated marketing fees in the combined statements of operations for the years ended 2004 and 2003, respectively

Natural Gas Sales. Calpine and CES executed index based natural gas sales under master agreements. Many of these transactions were executed by CPS on behalf of the Calpine; however, Calpine sold directly to CPS and CES prior to the agency agreement with CPS being executed. Oil and natural gas sales to affiliates were $81.9 million for the six months ended June 30, 2005 and $190.2 million and $223.5 million for the years ended December 31, 2004 and 2003, respectively.

Natural gas balancing activities between CES and Calpine, where Calpine bought back natural gas above the needs of CES and then re-sold that excess natural gas to third parties was recorded net to affiliated marketing fees in the combined statements of operations. The net effect of these balancing activities resulted in a gain or loss in the respective period. The net balancing cost (reduction of cost) for the years ended December 31, 2004 and 2003 are $(0.1) million and $0.3 million, respectively and for the six months ended June 30, 2005 there was no net balancing cost.

Notes Payable to Affiliates. Prior to the acquisition in July 2005, the Company and Calpine had an agreement whereby Calpine loaned the Company funds for capital expenditures, as well as operating costs. The Company repaid the balance of the note to Calpine as excess cash was available from continuing operations and asset sales. Interest on the note was compounded monthly at an annual rate of 8.75% during 2002 and 2003 and for the period through July of 2004, when the rate became variable, raising from 9.0% in August 2004 to 9.05% in December 2004. Additionally, the Company received equipment transferred from CPN Pipeline Company (Pipeline) during 2004 that was transferred at historical cost as the transaction was between entities under common control. The Company s payable to Pipeline was subsequently transferred to Calpine and increased the note discussed above. As part of certain credit facilities entered into by Calpine, the security included direct liens on the domestic oil and natural gas properties. The balance of Notes payable to Affiliates was $127.2 million for the year ended December 31, 2004. Notes payable of $92.9 million were retired at the time of acquisition of the oil and natural gas business of Calpine.

Other Services. Calpine provided general services to other subsidiaries of Calpine that were recorded in accounts receivables from affiliates on the combined balance sheets and other revenue on the combined statements of operations, which were insignificant.

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SUPPLEMENTAL OIL AND GAS DISCLOSURES

(Unaudited)

Oil and Natural gas Producing Activities

The following disclosures for the Company are made in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, Disclosures About Oil and Natural gas Producing Activities (an amendment of FASB Statements 19, 25, 33 and 39) (SFAS No. 69). Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of natural gas and crude oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

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

Estimates of proved developed and proved undeveloped reserves as of December 31, 2005, 2004 and 2003, were based on estimates made by Netherland Sewell independent petroleum engineers.

Our independent engineers, Netherland, Sewell & Associates, Inc., are engaged by and provide their reports to our senior management team. We make representations to the independent engineers that we have provided all relevant operating data and documents, and in turn, we review these reserve reports provided by the independent engineers to ensure completeness and accuracy. Our Chairman of the Board, President and Chief Executive Officer makes the final decision on booked proved reserves by incorporating the proved reserves from the independent engineers reports.

Our relevant management controls over proved reserve attribution, estimation and evaluation include:

- controls over and processes for the collection and processing of all pertinent operating data and documents needed by our independent reservoir engineers to estimate our proved reserves;

- engagement of well qualified and independent reservoir engineers for review of our operating data and documents and preparation of reserve reports annually in accordance with all SEC reserve estimation guidelines; and review by our senior reservoir engineer and his staff of the independent reservoir engineers reserves reports for completion and accuracy.

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

In accordance with SFAS No. 144 Accounting for Impairment or Disposal of Long-Lived Assets (SFAS No. 144), United States natural gas reserves and petroleum asset divestments were accounted for as discontinued operations in preparing SFAS No. 69 data.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company s natural gas and crude oil producing activities at December 31, 2005 and 2004 (in thousands):

	Successor	**Predecessor**
	2005	**2004**
Proved properties (1)	$ 951,968	$ 1,095,022
Unproved properties (1)	21,217	10,538
Total	973,185	1,105,560
Less: accumulated depreciation, depletion and amortization	40,029	500,722
Net capitalized costs	$ 933,156	$ 604,838
Company s share of equity method investees net capitalized costs	$ 181	$ 1,160

(1) Full cost method (successor) and successful efforts method (predecessor).

Pursuant to SFAS No. 143 Accounting for Asset Retirement Obligations , net capitalized cost includes asset retirement cost of $9,117 and $6,560 as of December 31, 2005, and December 31, 2004, respectively.

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

The following table sets forth costs incurred related to the Company s oil and natural gas activities for the six months ended December 31, 2005 (successor) and June 30, 2005 (predecessor) and the years ended December 31, 2004 and 2003 (predecessor) (in thousands):

	Continuing Operations	Discontinued Operations
Six Months Ended December 31, 2005 (successor):		
Acquisition costs of properties		
Proved(1)	$ 915,700	$
Unproved	21,930	
Subtotal	937,630	
Exploration costs	19,294	
Development costs	35,915	
Total	$ 992,839	$
Company s share of equity method investees costs of property acquisition, exploration and development	$ 181	$

(1) Includes acquisition of Calpine s oil and natural gas business of $910,064.

	Continuing Operations	Discontinued Operations
Six Months Ended June 30, 2005 (predecessor):		
Acquisition costs of properties		
Proved	$	$
Unproved	1,640	
Subtotal	1,640	
Exploration costs	13,110	
Development costs	20,233	
Total	$ 34,983	$
Calpine s share of equity method investees costs of property acquisition, exploration and development	$ 25	$
Year Ended December 31, 2004 (predecessor):		
Acquisition costs of properties		
Proved	$ 1,425	$ 558
Unproved	3,060	55
Subtotal	4,485	613
Exploration costs	22,471	214
Development costs	42,038	5,706
Total	$ 68,994	$ 6,533
Calpine s share of equity method investees costs of property acquisition, exploration and development	$ 56	$ 2,020

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	Continuing Operations	Discontinued Operations
Year Ended December 31, 2003 (predecessor):		
Acquisition costs of properties		
Proved	$ 8,178	$ 5,978
Unproved	13,597	20
Subtotal	21,775	5,998
Exploration costs	33,364	2,765
Development costs	41,911	16,219
Total	$ 97,050	$ 24,982
Calpine s share of equity method investees costs of property acquisition, exploration and development	$ 1,268	$ 53,039

Results of Operations for Oil and Natural Gas Producing Activities (In thousands)

	Successor		Predecessor	
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003
Oil and natural gas production revenues				
Third-party	$ 113,090	$ 21,803	$ 57,572	$ 56,230
Affiliate		81,952	190,215	223,464
Total revenues	113,090	103,755	247,787	279,694
Exploration expenses, including dry hole		4,317	7,440	16,729
Production costs	22,314	22,295	40,503	40,956
Depreciation, depletion and amortization	40,500	30,679	81,590	72,766
Oil and natural gas impairment			202,120	2,931
Income (loss) before income taxes	50,276	46,464	(83,866)	146,312
Income tax provision (benefit)	19,155	17,656	(31,869)	55,599
Results of continuing operations	$ 31,121	$ 28,808	$ (51,997)	$ 90,713
Results of discontinued operations	$	$	$ 7,162	$ 6,903
Company s share of equity method investees results of operations for producing activities	$ 241	$ 161	$ 324	$ 86

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

Net Proved and Proved Developed Reserve Summary

The following table sets forth the Company s net proved and proved developed reserves (all within the United States) at December 31, 2005, 2004 and 2003, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the independent petroleum consultants. During the six months ended December 31, 2005, other relates to reserves associated with non-consent properties. See Note 2.

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During 2004, Calpine revised downward its estimate of continuing proved reserves by a total of approximately 58 Bcfe or 12%. Approximately 69% of the total revision was attributable to the downward revision of Calpine s estimate of proved reserves in the South Texas fields due to information received from production results and drilling activity that occurred during 2004. The remaining 31% of the total revision was due to the downward revision of Calpine s estimate of proved reserves in California of 17%, Other Onshore of 10% and Gulf of Mexico of 4%. As a result of the decreases in proved undeveloped reserves, Calpine recorded a non-cash impairment charge of approximately $202.1 million was recorded for the year ended December 31, 2004. For the years ended December 31, 2003, the impairment charge recorded to the same line item was $2.9 million.

	Continuing Operations	Discontinued Operations
Natural gas (Bcf)(1):		
Net proved reserves at January 1, 2003 (predecessor)	479	96
Revisions of previous estimates	(21)	(4)
Purchases in place	1	6
Extensions, discoveries and other additions	51	7
Sales in place	(5)	
Production	(50)	(5)
Net proved reserves at December 31, 2003 (predecessor)	455	100
Revisions of previous estimates	(60)	14
Purchases in place	1	
Extensions, discoveries and other additions	17	5
Sales in place	(2)	(115)
Production	(37)	(4)
Net proved reserves at December 31, 2004 (predecessor)	374	
Revisions of previous estimates	(11)	
Purchases in place		
Extensions, discoveries and other additions	28	
Sales in place		
Production	(27)	
Other(5)	(19)	
Net proved reserves at December 31, 2005 (successor)(6)	345	
Company s proportional interest in reserves of investees accounted for by the equity method December 31, 2005 (successor)	5	
Natural gas liquids and crude oil (MBbl)(2)(3):		
Net proved reserves at January 1, 2003 (predecessor)	3,531	578
Revisions of previous estimates	(338)	(19)
Purchases in place	18	1
Extensions, discoveries and other additions	133	33
Sales in place	(8)	(105)
Production	(434)	(22)
Net proved reserves at December 31, 2003 (predecessor)	2,902	466
Revisions of previous estimates	260	(15)
Purchases in place	3	
Extensions, discoveries and other additions	48	16

Sales in place	(2)	(451)
Production	(600)	(16)

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	Continuing Operations	Discontinued Operations
Net proved reserves at December 31, 2004 (predecessor)	2,611	
Revisions of previous estimates	153	
Purchases in place		
Extensions, discoveries and other additions	108	
Sales in place	(9)	
Production	(360)	
Other(5)	(22)	
Net proved reserves at December 31, 2005 (successor)(6)	2,481	
Company s proportional interest in reserves of investees accounted for by the equity method December 31, 2005 (successor)		
(Bcfe)(1) equivalents(4):		
Net proved reserves at January 1, 2003 (predecessor)	499	101
Revisions of previous estimates	(23)	(4)
Purchases in place	1	6
Extensions, discoveries and other additions	52	7
Sales in place	(5)	(1)
Production	(52)	(6)
Net proved reserves at December 31, 2003 (predecessor)	472	103
Revisions of previous estimates	(58)	14
Purchases in place	1	
Extensions, discoveries and other additions	17	5
Sales in place	(2)	(118)
Production	(41)	(4)
Net proved reserves at December 31, 2004 (predecessor)	389	
Revisions of previous estimates	(10)	
Purchases in place		
Extensions, discoveries and other additions	29	
Sales in place		
Production	(30)	
Other(5)	(19)	
Net proved reserves at December 31, 2005 (successor)(6)	359	
Company s proportional interest in reserves of investees accounted for by the equity method December 31, 2005 (successor)	5	
Net proved developed reserves:		
Natural gas (Bcf)(1)		
December 31, 2003 (predecessor)	306	63
December 31, 2004 (predecessor)	256	
December 31, 2005 (successor)(6)	223	

Natural gas liquids and crude oil (MBbl)(2)(3)		
December 31, 2003 (predecessor)	1,508	362
December 31, 2004 (predecessor)	1,402	
December 31, 2005 (successor)(6)	1,320	

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	Continuing Operations	Discontinued Operations
Bcf(1) equivalents(4)		
December 31, 2003 (predecessor)	315	65
December 31, 2004 (predecessor)	264	
December 31, 2005 (successor)(6)	231	

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

(2) Thousand barrels.

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

(4) Natural gas liquids and crude oil volumes have been converted to equivalent natural gas volumes using a conversion factor of six cubic feet of natural gas to one barrel of natural gas liquids and crude oil.

(5) Reserves associated with non-consent properties.

(6) Excludes reserves associated with non-consent properties.

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

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company s oil and natural gas assets.

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

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

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The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company s natural gas and crude oil reserves for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Continuing Operations	Discontinued Operations
December 31, 2005 (successor):		
Future cash inflows	$ 3,232	$
Future production costs	(647)	
Future development costs	(244)	
Future net cash flows before income taxes	2,341	
Future income taxes	(487)	
Future net cash flows	1,854	
Discount to present value at 10% annual rate	(738)	
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 1,116	$
Company s share of equity method investees standardized measure of discounted future net cash flows	$ 2	$

	Continuing Operations	Discontinued Operations
December 31, 2004 (predecessor):		
Future cash inflows	$ 2,427	$
Future production costs	(568)	
Future development costs	(190)	
Future net cash flows before income taxes	1,669	
Future income taxes	(474)	
Future net cash flows	1,195	
Discount to present value at 10% annual rate	(542)	
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 653	$
Calpine s share of equity method investees standardized measure of discounted future net cash flows	$ 2	$

	Continuing Operations	Discontinued Operations
December 31, 2003 (predecessor):		
Future cash inflows	$ 2,752	$ 613
Future production costs	(563)	(180)
Future development costs	(200)	(39)

Future net cash flows before income taxes		1,989		394
Future income taxes		(553)		(113)
Future net cash flows		1,436		281
Discount to present value at 10% annual rate		(661)		(131)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$	775	$	150
Calpine s share of equity method investees standardized measure of discounted future net cash flows	$	2	$	18

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Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2005, 2004 and 2003 (in millions):

	Continuing Operations	Discontinued Operations
Balance, January 1, 2003 (predecessor)	$ 680	$ 96
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(239)	(19)
Net changes in prices and production costs	248	68
Extensions, discoveries, additions and improved recovery, net of related costs	117	16
Development costs incurred	48	16
Revisions of previous quantity estimates and development costs	(80)	(11)
Accretion of discount	68	10
Net change in income taxes	(28)	(24)
Purchases of reserves in place	2	8
Sales of reserves in place	(6)	
Changes in timing and other	(35)	(10)
Balance, December 31, 2003 (predecessor)	$ 775	$ 150
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(205)	(18)
Net changes in prices and production costs	39	2
Extensions, discoveries, additions and improved recovery, net of related costs	60	11
Development costs incurred	25	5
Revisions of previous quantity estimates and development costs	(193)	10
Accretion of discount	78	15
Net change in income taxes	39	59
Purchases of reserves in place	2	
Sales of reserves in place	(5)	(208)
Changes in timing and other	38	(26)
Balance, December 31, 2004 (predecessor)	$ 653	$
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(184)	
Net changes in prices and production costs	526	
Extensions, discoveries, additions and improved recovery, net of related costs	123	
Development costs incurred	89	
Revisions of previous quantity estimates and development costs	(84)	
Accretion of discount	74	
Net change in income taxes	(55)	
Purchases of reserves in place		
Sales of reserves in place		
Changes in timing and other	(26)	
Balance, December 31, 2005 (successor)(1)	$ 1,116	$

(1) Excludes non-consent properties

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Rosetta Resources Inc.

Selected Data (Unaudited)

Quarterly Information (Unaudited)

Summaries of the Company s results of operations by quarter for the years ended 2005 and 2004 are as follows:

	Predecessor(1)		Successor(1)		
			Quarter Ended		
			September 30		
	March 31	June 30	As Previously Reported	Restated(2)	December 31
			(In thousands)		
2005					
Revenues	$ 50,555	$ 53,276	$ 57,865	$ 57,865	$ 55,239
Operating income	$ 20,449	$ 16,414	$ 18,295	$ 17,240	$ 18,363
Net income	$ 10,662	$ 8,019	$ 9,262	$ 8,207	$ 9,328
Earnings per share:					
Basic	$ 0.21	$ 0.16	$ 0.19	$ 0.16	$ 0.19
Diluted	$ 0.21	$ 0.16	$ 0.18	$ 0.16	$ 0.19

	Predecessor Quarter Ended			
	March 31	June 30	September 30(3)	December 31(4)
	(In thousands)			
2004				
Revenues	$ 59,932	$ 67,115	$ 57,709	$ 63,250
Operating income (loss)	$ 24,046	$ 28,164	$ 20,549	($ 175,822)
Net income (loss)	$ 11,796	$ 16,236	$ 75,534	($ 113,962)
Earnings (loss) per share:				
Basic	$ 0.24	$ 0.32	$ 1.51	($ 2.28)
Diluted	$ 0.24	$ 0.32	$ 1.51	($ 2.28)

(1) Differences in accounting principles of the predecessor and successor exist and will affect the comparability of the data. Differences primarily relate to the full cost method of accounting adopted by the Company and the successful efforts method of accounting followed by the predecessor and differences in accounting for stock based compensation. See Note 3.

(2) See below for previously reported and restated Consolidated Balance Sheet at September 31, 2005 and previously reported and restated Consolidated Statement of Operations, Consolidated Statement of Cash Flows and Consolidated Statement of Changes in Stockholders Equity and Comprehensive Income for the three months ended September 30, 2005.

(3) Includes gain on property sales of $64.9 million, after tax, during the quarter related to the sale of Rocky Mountain natural gas properties concentrated in the Colorado Piceance Basin and the New Mexico San Juan Basin.

(4) Includes an impairment charge of $202.1 million for certain fields in South Texas and Gulf of Mexico which had net book values in excess of the undiscounted future net cash flows associated with their proved reserve estimates.

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Restatement of Previously Issued Financial Statements

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, from what we previously disclosed in our registration statement on Form S-1 (333-128888), particularly in our Selected Historical Consolidated/Combined 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 effect of this restatement for the three months ended September 30, 2005 is as follows:

Increase (Decrease) in Net Income (in thousands)

	Successor Three Months Ended September 30,
2005	
Net income, as previously reported	$ 9,262
Offering costs expensed	1,055
Net income, restated	$ 8,207
% change	11.4%

The following tables set forth the effects of the restatement adjustments on affected line items within our previously reported Consolidated Statement of Income for the three months ended September 30, 2005 and the Consolidated Balance Sheet as of September 30, 2005. The line items of net income and equity offering transaction fees in financing activities were affected by $1.1 million in the Statement of Cash Flows for the three months ended September 30, 2005.

Consolidated Statement of Income

Three Months Ended September 30, 2005

	Successor	
	As Previously Reported	**Restated**
General and administrative expenses	$ 5,825	$ 6,880
Total costs and expense	39,570	40,625
Operating income	18,295	17,240
Income before provision for taxes	14,939	13,884
Net income	$ 9,262	$ 8,207
Earnings per share:		
Basic	$ 0.19	$ 0.16
Diluted	$ 0.18	$ 0.16

Consolidated Balance Sheet

September 30, 2005

	Successor	
	As Previously Reported	Restated
Other current liabilities	$ 18,672	$ 18,568
Total current liabilities	124,437	124,333
Total liabilities	413,299	413,195
Additional paid-in capital	747,443	748,602
Retained earnings	9,262	8,207
Total stockholders equity	690,309	690,413

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The following are previously reported and restated financial statements as of and for the three months ended September 30, 2005.

Rosetta Resources Inc.

Consolidated Balance Sheet

(Unaudited)

	Successor	
	As Previously Reported	Restated
	(In thousands)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 106,973	$ 106,973
Accounts receivable	33,570	33,570
Prepaid expenses	3,305	3,305
Total current assets	143,848	143,848
Oil and natural gas properties, full cost	933,213	933,213
Other	1,837	1,837
Total property and equipment	935,050	935,050
Accumulated depreciation, depletion, and amortization	(21,476)	(21,476)
Total property and equipment, net	913,574	913,574
Long-term accounts receivable	2,107	2,107
Deferred tax asset	37,801	37,801
Deferred loan fees	5,145	5,145
Other assets	1,133	1,133
Total other assets	46,186	46,186
Total assets	$ 1,103,608	$ 1,103,608
Liabilities and Stockholders Equity		
Current Liabilities:		
Accounts payable	$ 4,352	$ 4,352
Royalties payable	32,913	32,913
Current income tax payable	2,271	2,271
Commodity hedging liability	66,107	66,107
Interest payable	122	122
Other current liabilities	18,672	18,568
Total current liabilities	124,437	124,333
Long-term liabilities		
Commodity hedging liability	41,064	41,064
Long-term debt	240,000	240,000
Asset retirement obligation	7,798	7,798

Total liabilities	413,299	413,195
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.001 par value, 50,000,000 shares authorized, issued and outstanding	50	50
Additional paid-in capital	747,443	748,602
Accumulated other comprehensive loss	(66,446)	(66,446)
Retained Earnings	9,262	8,207
Total stockholders equity	690,309	690,413
Total liabilities and stockholders equity	$ 1,103,608	$ 1,103,608

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Rosetta Resources Inc.

Consolidated Statement of Operations

(Unaudited)

	Successor	
	As Previously Reported Three Months Ended September 30, 2005	Restated Three Months Ended September 30, 2005
	(In thousands, except per share and share amounts)	
Revenues:		
Oil sales	$ 6,204	$ 6,204
Natural gas sales	51,655	51,655
Other revenue	6	6
Total revenues	57,865	57,865
Operating Costs and Expenses:		
Lease operating expense	8,849	8,849
Depreciation, depletion, and amortization	21,720	21,720
Treating and transportation	552	552
Marketing fees	678	678
Production taxes	1,946	1,946
General and administrative costs	5,825	6,880
Total operating costs and expenses	39,570	40,625
Operating income	18,295	17,240
Other (income) expense		
Interest expense, net of interest capitalized	4,077	4,077
Interest income	(874)	(874)
Other expense, net	153	153
Total other expense	3,356	3,356
Income Before Provision for Income Taxes	14,939	13,884
Provision for income taxes	5,677	5,677
Net income	$ 9,262	$ 8,207
Earnings per share:		
Basic	$ 0.19	$ 0.16
Diluted	$ 0.18	$ 0.16
Weighed average shares outstanding:		

Basic	50,000	50,000
Diluted	50,160	50,160

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(Unaudited)

	Successor	
	As Previously Reported Three Months Ended September 30, 2005	Restated Three Months Ended September 30, 2005
	(In thousands)	
Cash flows from operating activities		
Net income	$ 9,262	$ 8,207
Adjustments to reconcile net income from continuing operations to net cash from operating activities		
Depreciation, depletion and amortization	21,720	21,720
Deferred income taxes	3,406	3,406
Income from unconsolidated investments	(112)	(112)
Stock compensation expense	1,710	1,710
Change in operating assets and liabilities:		
Accounts receivable	(33,570)	(33,570)
Prepaid expenses	(3,305)	(3,305)
Long-term accounts receivable	(2,107)	(2,107)
Royalties payable	32,913	32,913
Accounts payable	24,098	24,098
Interest payable	122	122
Current income taxes payable	2,271	2,271
Other current liabilities	8,001	7,897
Cash provided by operating activities	64,409	63,250
Cash flows from investing activities		
Acquisition, net of cash acquired	(910,064)	(910,064)
Purchases of property and equipment	(26,507)	(26,507)
Deposits	(201)	(201)
Investment in non-affiliated subsidiary	(820)	(820)
Net cash used in investing activities	(937,592)	(937,592)
Cash flows from financing activities		
Equity offering proceeds	800,000	800,000
Equity offering transaction fees	(54,699)	(53,540)
Borrowings on term loan	100,000	100,000
Payments on term loan	(25,000)	(25,000)
Borrowings on revolving credit facility	225,000	225,000
Payments on revolving credit facility	(60,000)	(60,000)
Loan fees	(5,145)	(5,145)

Net cash provided by financing activities	980,156	981,315
Net increase in cash	106,973	106,973
Cash and cash equivalents, beginning of period		
Cash and cash equivalents, end of period	$ 106,973	$ 106,973
Supplemental disclosures:		
Cash paid for interest	$ 4,221	$ 4,221
Supplemental non-cash transaction:		
Net capital expenditures included in liabilities	$ (1,670)	$ (1,670)

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Rosetta Resources Inc.

Consolidated Statement of Changes in Stockholders Equity

and Comprehensive Income, As Previously Reported

(Unaudited)

	Common Stock		Additional Paid-In Capital	Accumulated Other Comprehensive (Loss)	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
			(In thousands, except share amounts)			
Successor						
Comprehensive income:						
Net income		$	$	$	$ 9,262	$ 9,262
Change in fair value of derivative hedging instruments				(109,392)		(109,392)
Hedge settlement reclassified to income				2,221		2,221
Tax (provision)/benefit related to cash flow hedges				40,725		40,725
Comprehensive income						(57,184)
Issuance of common stock, net of offering costs	50,000,000	50	745,733			745,783
Vesting of Restricted Stock			1,710			1,710
Balance at September 30, 2005 (Unaudited)	50,000,000	$ 50	$ 747,443	$ (66,446)	$ 9,262	$ 690,309

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Rosetta Resources Inc.

Consolidated Statement of Changes in Stockholders Equity

and Comprehensive Income, Restated

(Unaudited)

	Common Stock		Additional Paid-In Capital	Accumulated Other Comprehensive (Loss)	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
			(In thousands, except share amounts)			
Successor						
Comprehensive income:						
Net income		$	$	$	$ 8,207	$ 8,207
Change in fair value of derivative hedging instruments				(109,392)		(109,392)
Hedge settlement reclassified to income				2,221		2,221
Tax (provision)/benefit related to cash flow hedges				40,725		40,725
Comprehensive income						(58,239)
Issuance of common stock, net of offering costs	50,000,000	50	746,892			746,942
Vesting of Restricted Stock			1,710			1,710
Balance at September 30, 2005 (Unaudited)	50,000,000	$ 50	$ 748,602	$ (66,446)	$ 8,207	$ 690,413

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act), as of December 31, 2005. Disclosure controls and procedures are those controls and procedures designed to provide reasonable assurance that the information required to be disclosed in our Exchange Act filings is (1) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission s rules and forms, and (2) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2005, our disclosure controls and procedures were not effective, at the reasonable assurance level, due to the identification of the material weaknesses in internal control over financial reporting described below. Notwithstanding the material weaknesses described below, we believe our consolidated financial statements included in this Annual Report on Form 10-K fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in accordance with generally accepted accounting principles.

In preparing our Exchange Act filings, including this Annual Report on Form 10-K, we implemented processes and procedures to provide reasonable assurance that the identified material weaknesses in our internal control over financial reporting were mitigated with respect to the information that we are required to disclose. As a result, we believe, and our Chief Executive Officer and Chief Financial Officer have certified to their knowledge, that this Annual Report on Form 10-K does not contain any untrue statements of material fact or omit to state any material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered in this Annual Report.

Material Weaknesses in Internal Control Over Financial Reporting

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. We have identified various deficiencies in internal control over financial reporting. We believe that many of these are attributable to our transition from a subsidiary of a much larger company to a standalone entity. In connection with the preparation of our 2005 consolidated financial statements and our assessment of the effectiveness of our disclosure controls and procedures as of December 31, 2005 to be included in this, our first Annual Report on Form 10-K to be filed under the Exchange Act, we identified the following specific control deficiencies, which represent material weaknesses in our internal control over financial reporting as of December 31, 2005:

a) We did not have a sufficient complement of permanent personnel to have an appropriate accounting and financial reporting organizational structure to support the activities of the Company. Specifically, we did not have permanent personnel with an appropriate level of accounting knowledge, experience and training in the selection, application and implementation of generally accepted accounting principles and financial reporting commensurate with our financial reporting requirements.

b) We did not have effective controls as it relates to the identification and documentation of accounting policies, including selection and application of generally accepted accounting principles used for accounting

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for select transactions and other activities. This deficiency resulted in a reduced ability to ensure the timely and accurate recording of certain transactions and activities primarily relating to accounting for derivatives and debt modifications. As a result, we did not have sufficient procedures to ensure significant underlying select transactions were appropriately and timely accounted for in the general ledger.

In addition these material weaknesses could result in a misstatement of substantially all accounts and disclosures which would result in a material misstatement of annual or interim financial statements that would not be prevented or detected. Accordingly, management has concluded that these control deficiencies constitute material weaknesses.

Remediation Activities

As discussed above, management has identified certain material weaknesses that exist in our internal control over financial reporting and management is taking steps to strengthen our internal control over financial reporting. During the first quarter of 2006, we hired additional accounting personnel and began improving our documentation of our accounting policies and procedures. Specifically, during the first quarter of 2006 we have taken the following remedial actions:

1. We have hired a certified public accountant with specific expertise in accounting software systems to evaluate and implement further enhancements to our software and related procedures to improve our accounting controls;

2. We have replaced our manager of fixed assets and accounts payable with a more highly credentialed person having a masters degree in business administration who is also a certified public accountant;

3. We have hired a person to fill the position of manager of internal audit to review and audit our internal control environment and make recommendations for improvement; and

4. We have authorized the additional position of manager of financial reporting and have extended an offer to a qualified person for this position. We expect this position to be filled shortly.

While we have taken certain actions to address the material weaknesses identified, additional measures will be necessary and these measures, along with other measures we expect to take to improve our internal control over financial reporting, may not be sufficient to address the material weaknesses identified to provide reasonable assurance that our internal control over financial reporting is effective. In addition, we may in the future identify additional material weaknesses in our internal control over financial reporting.

Beginning with the year ending December 31, 2007, pursuant to Section 404 of the Sarbanes-Oxley Act, we will be required to deliver a report that assesses the effectiveness of our internal control over financial reporting, and our auditors will be required to audit and report on our assessment of and the effectiveness of our internal control over financial reporting. We have a substantial effort ahead of us to complete the documentation and testing of our internal control over financial reporting and remediate any additional material weaknesses identified during that activity. Accordingly, we may not be able to complete the required management assessment by our reporting deadline. An inability to complete this assessment would result in receiving something other than an unqualified report from our auditors with respect to our assessment of our internal control over financial reporting. In addition, if material weaknesses are not remediated, we would not be able to conclude that our internal control over financial reporting was effective, which would result in the inability of our external auditors to deliver an unqualified report on the effectiveness of our internal control over financial reporting.

Item 9B. Other Information.

None.

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PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required to be contained in this Item is incorporated by reference from Part I of this report and by reference to our definitive proxy statement to be filed with respect to our 2006 annual meeting.

Item 11. Executive Compensation.

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2006 annual meeting under the heading Executive Compensation .

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

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2006 annual meeting under the heading Principal Stockholders and Security Ownership of Management .

Item 13. Certain Relationships and Related Transactions.

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2006 annual meeting under the heading Certain Transactions .

Item 14. Principal Accountant Fees and Services.

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2006 annual meeting.

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PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) (1) Financial Statements:

The following financial statements and the Report of Independent Registered Public Accounting Firm are filed as a part of this report on the pages indicated:

(2) Financial Statements Schedules:

None.

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(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.1	Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on April 19, 2006.

ROSETTA RESOURCES INC.

By: /s/ B.A. BERILGEN
B.A. Berilgen, Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1933, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ B.A. BERILGEN **B.A. Berilgen**	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	April 19, 2006
/s/ MICHAEL J. ROSINSKI **Michael J. Rosinski**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	April 19, 2006
/s/ DENISE D. BEDNORZ **Denise D. Bednorz**	Vice President, Controller (Principal Accounting Officer)	April 19, 2006
/s/ RICHARD W. BECKLER **Richard W. Beckler**	Director	April 19, 2006
/s/ DONALD D. PATTESON, JR. **Donald D. Patteson, Jr.**	Director	April 19, 2006
/s/ D. HENRY HOUSTON **D. Henry Houston**	Director	April 19, 2006

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

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

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

Appraisal well. A well drilled several spacing locations away from a producing well to determine the boundaries or extent of a productive formation and to establish the existence of additional reserves.

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

Bcf. Billion cubic feet of natural gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mcf. Thousand cubic feet of natural gas.

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

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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

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

Net revenue interest. An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, net profits interests, carried interests, reversionary interests and any other burdens to which the person s interest is subject.

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

NYMEX. New York Mercantile Exchange.

OCS block. Outer continental shelf block located outside the state territorial limit.

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

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

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

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

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

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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Progradation. The accumulation of sequences by deposition in which beds are deposited successively basinward because sediment supply exceeds accommodation.

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

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. See Rule 4-10(a), paragraph (3) for a more complete definition.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. See Rule 4-10(a), paragraph (4) for a more complete definition.

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

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

Resistivity. The ability of a material to resist electrical conduction. Resistivity is used to indicate the presence of water and /or hydrocarbons.

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

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

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

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

Tcf. Trillion cubic feet of natural gas.

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

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

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

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

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

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

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

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

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