Rosetta Resources Inc.
Form 10-K
February 29, 2008

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

FORM 10-K

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

For The Fiscal Year Ended December 31, 2007

OR

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

Commission File Number: 000-51801

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

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

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

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

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

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

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

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

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 S No £

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

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

Large accelerated filer S	Accelerated filer £
Non-Accelerated filer £	Smaller Reporting Company £
(Do not check if smaller reporting company)	

Indicate by check mark whether the Registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act). Yes £ No S

The aggregate market value of the voting and non-voting common equity held by Non-affiliates of the registrant as of June 29, 2007 was approximately $1.1 billion based on the closing price of $21.54 per share on the Nasdaq Global Select Market.

The number of shares of the registrant's Common Stock, $.001 par value per share outstanding as of February 18, 2008 was 51,146,322.

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 natural gas terms, see page 95.

Part I

Item 1. Business

General

We are an independent oil and gas company engaged in the acquisition, exploration, development and production of oil and gas properties in North America. Our operations are concentrated in the Sacramento Basin of California, the Rocky Mountains, the Lobo and Perdido trends in South Texas, the State Waters of Texas and the Gulf of Mexico. We are a Delaware corporation based in Houston, Texas.

Rosetta Resources Inc. (together with our consolidated subsidiaries, the "Company") was formed in June 2005 to acquire Calpine Natural Gas L.P., its partners and the domestic oil and natural gas business formerly owned by Calpine Corporation and its affiliates ("Calpine"). We ("Successor") acquired Calpine Natural Gas L.P. and its partners ("Predecessor") and Rosetta Resources California, LLC, Rosetta Resources Rockies, LLC, Rosetta Resources Offshore, LLC and Rosetta Resources Texas LP and its partners, in July 2005 (hereinafter, the "Acquisition"). We have subsequently acquired numerous other oil and natural gas properties, and we are engaged in oil and natural gas exploration, development, production and acquisition activities in the United States. We operate in one business segment. See Note 15 to our consolidated/combined financial statements. We have grown our existing property base by developing and exploring our acreage; purchasing new undeveloped leases; acquiring oil and gas producing properties and drilling prospects from third parties.

Pursuant to the Acquisition, we entered into several operative contracts with Calpine, including a purchase and sale agreement and all interrelated agreements, concurrently executed on or about July 7, 2005 (collectively, the "Purchase Agreement") under which we have indemnification rights and obligations with respect to Calpine. Currently, Calpine markets our oil and gas under a marketing services agreement, whose original term ran through June 30, 2007. In connection with the partial transfer and release agreement executed by Calpine and the Company on August 3, 2007 (the "PTRA"), a new marketing agreement was entered into whose term is from July 1, 2007 through June 30, 2009, subject to earlier termination on certain events. We also sell a significant portion of our gas to Calpine pursuant to certain gas purchase and sales contracts, all of which were part of the Purchase Agreement. The PTRA and gas purchase and sales contracts with Calpine are discussed further under Part I. Item 3. Legal Proceedings.

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, the Rocky Mountains, South Texas, the State Waters of Texas and the Gulf of Mexico. 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. We also believe our current asset base provides a strong platform for additional acquisitions.

Development and Exploration Drilling Inventory. We have identified an inventory of low to moderate risk opportunities providing us with multiple years of drilling, and we expect to drill approximately 190 of these locations during 2008. Approximately 20% of these locations are classified as proved undeveloped. We also believe we have access to a large and diversified portfolio of non-proved resource inventory that will drive future growth. Our capital expenditure budget is $290.1 million for 2008. 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.

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Operational Control. We operate approximately 88% 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, New Leadership. Our executive management team has an average of 29 years of experience in the energy industry with specific experience in the areas where our primary properties are located. In November 2007, Randy L. Limbacher became our President and Chief Executive Officer ("CEO") replacing B. A. Berilgen who resigned in 2007. Mr. Limbacher personally has 27 years of experience in the energy industry, most recently serving as President, Exploration and Production - Americas for ConocoPhillips.

Proven Technical and Land Personnel with Access to Technological Resources. Our technical staff includes 36 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, operating in complex basins and managing coalbed methane operations. These core competencies helped us to achieve a drilling success rate of 82% for the year ended December 31, 2007 and has helped maximize recovery from our reservoirs. Our definition of drilling success is a well that is producing or capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Previously, our definition of a successful well was a well that produced hydrocarbons at sufficient rates to allow us to recover, at a minimum, our capital investment and operating costs. Under the previous definition, our success rate would have been 72%.

Our Strategy

Our strategy is to increase stockholder value by managing our reserves, production, cash flow and profitability using a balanced program of (1) developing and extending inventory in existing core properties, (2) establishing new resource based core areas, (3) exploitation and exploration activities, (4) completing acquisitions and selective divestitures, (5) maintaining technical expertise, (6) focusing on cost control and (7) maintaining financial flexibility. We will seek to accomplish these goals while working to protect stockholders interests by focusing on sustainability, spending our various resources wisely, monitoring emerging trends, minimizing liabilities through governmental compliance, respecting the dignity of human life, and protecting the environment. The following are key elements of our strategy:

Developing and Extending Existing Core Properties. We have designated the Sacramento Basin, the DJ Basin and South Texas as core areas and intend to build our asset base in these areas through additional leasing and acquisitions where applicable. We intend to further develop the upside potential of these core properties by working over existing wells, drilling in-fill locations, drilling step-out wells to expand known field outlines, recompleting to logged behind pipe pays and lowering field line pressures through compression for additional reserve recovery.

Establishing New Resource Based Core Areas. We intend to extend our presence into new core areas within North America that are characterized by significant presence of resource potential that can be exploited utilizing our technological expertise.

Exploitation and Exploration Activities. We intend to generate growth in existing and new core areas in which we have technological and operational advantages by identifying exploitation and exploration opportunities that contain the potential to establish repeatable drilling programs.

Completing Acquisitions and Selective Divestitures. We continually review opportunities to optimize our portfolio to create stockholder value. We actively evaluate possible acquisitions of producing properties, undeveloped acreage and drilling prospects in our existing core areas, as well as areas where we believe we can establish new core areas by implementing an “acquire and exploit” strategy. We will focus on opportunities where we believe our reservoir management and operational expertise will enhance the value and performance of the acquired properties through development and exploration based on repeatable drilling programs. Periodically, we also evaluate possible divestitures of properties that we believe have limited future potential or that do not fit our risk profile.

Maintaining Technological Expertise. We intend to maintain and further develop the technological expertise that helped us achieve a drilling success rate of 82% for the year ended December 31, 2007 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.

Focusing on Cost Control. We will manage all elements of our cost structure including drilling and operating costs as well as overhead costs. We will strive to minimize our drilling and operating costs by concentrating our assets within existing and new sustainable resource based core areas.

Maintaining Financial Flexibility. We may optimize unused borrowing capacity under our revolving line of credit by refinancing our bank debt in the capital markets if conditions are favorable. As of December 31, 2007, we had $179.0 million available for borrowing under our revolving line of credit, with $170.0 million drawn 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 continue to actively manage our exposure to commodity price risk in the marketing of our oil and natural gas production. As part of this strategy 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. We also entered into a series of interest rate swap agreements to hedge the change in variable interest rates associated with our debt under our credit facility through June 2009. We may enter into other agreements, including fixed price, forward price, physical purchase and sales, futures, financial swaps, option and put option contracts.

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Calpine Bankruptcy

On December 20, 2005, Calpine and certain of its subsidiaries filed for protection under federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (the “Bankruptcy Court”).

On June 29, 2006, Calpine filed a motion pursuant to Bankruptcy Code Section 365 in connection with its bankruptcy proceedings and received an order from the Bankruptcy Court approving Calpine’s precautionary assumption of certain oil and gas leases which Calpine had previously sold or agreed to sell to us in the Acquisition, to the extent that the leases both constituted “unexpired leases of non-residential real property” and were not fully transferred to us at the time of Calpine’s filing for bankruptcy, in order to prevent Section 365’s “deemed rejection” of such leases. Calpine’s motion did not request that the Bankruptcy Court determine whether these properties belong to us or to Calpine. Generally, oil and gas leases are regarded as real property and not leases of real property despite their being called leases. If the Bankruptcy Court were to later conclude that the oil and natural gas leases are “unexpired leases of non-residential real property,” and that we had no interest in them, we may be asked to take further action or pay further consideration to complete the assignments of these interests or alternatively, Calpine might seek to retain the leases. In light of Calpine’s obligations under the Purchase Agreement and rights afforded purchasers of real property, we would oppose any such request or effort.

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 our 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 we remain hopeful that Calpine will continue to work cooperatively with us to secure these ministerial governmental approvals and accomplish the curative corrections for all of these properties for which we paid Calpine all of which are covered, we believe, by the further assurances provision of the Purchase Agreement; however, the exact details of each property involved and how, when and if this will be able to be secured or accomplished continue to remain uncertain pending conclusion of the adversary proceeding Calpine filed against us on June 29, 2007.

Any failure by Calpine to complete the corrective action necessary to remove title deficiencies with respect to these various properties, including a decision of the Bankruptcy Court not to require Calpine to deliver corrective documentation or to require us to pay additional consideration, could result in a material adverse effect on our business, results of operations, financial condition or cash flows if we are not able to receive any offsetting refund of the portion of the purchase price attributable to those properties or if the amount of additional consideration we are required to pay is material.

On August 1, 2006, we filed proofs of claim in the Calpine bankruptcy asserting claims against a variety of Calpine debtors seeking recovery of $27.9 million in liquidated amounts, as well as unliquidated damages in amounts that have not presently been determined.

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the “Lawsuit”) alleging that the Acquisition was a fraudulent conveyance and seeking to recover either the difference between the amounts it received in the transaction and the reasonably equivalent value of the business conveyed to us or the return of the business we acquired. We have answered and filed affirmative counterclaims against Calpine related to the Acquisition for (i) breach of covenant of solvency, (ii) fraud and fraud in a real estate transaction, (iii) breach of contract, (iv) conversion, (v) civil theft and (vi) setoff. The parties have engaged in an active motion practice in relation to these claims and counterclaims pertaining to the alleged fraudulent conveyance and discovery continues.

On September 11, 2007, the Bankruptcy Court approved the Partial Transfer and Release Agreement ("PTRA") that was executed by Calpine and the Company on August 3, 2007. Under the PTRA, Calpine resolved any title issues in order to allow us to have clear legal title in all offshore properties, certain properties for which the State of California was the lessor, and certain other properties involved in the Acquisition, without prejudice to Calpine’s claims and our counterclaims in the pending adversary proceeding. The PTRA did not include all properties that may have legal title issues, such as those properties that required non-governmental, third-party consents or waivers of preferential rights in order to place legal title of the assets in Rosetta’s name.

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On December 19, 2007, the Bankruptcy Court approved Calpine's plan of reorganization ("Plan of Reorganization"). Calpine declared January 31, 2008 as the "effective date" for consummation of its Plan of Reorganization and it is the date on which Calpine and certain of its subsidiaries emerged from bankruptcy.

We are continuing to vigorously defend and affirmatively assert our claims in connection with the meritless Lawsuit filed by Calpine.

See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy, PTRA, and the Lawsuit.

Our Operating Areas

We own producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Rocky Mountains, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico, and other properties 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 in order to provide the highest potential economic returns. For the year ended December 31, 2007, we have drilled 195 gross and 169 net wells, with a success rate of 82%. 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 for which legal title was not given to us on the original date of Acquisition because consents to transfer, which the parties believed at that time were required, had not been obtained as of July 7, 2005 and to certain properties for which we believe Calpine is obligated to provide further assurances. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

California-Sacramento Basin

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

As of December 31, 2007, we owned approximately 76,000 net acres in the Rio Vista Field and Sacramento Basin areas. Our acreage in the basin holds significant low-risk, low-cost upside potential, and numerous workover and recompletion opportunities. Additional reserve potential exists in gathering system optimization projects, fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

For the year ended December 31, 2007, our average net daily production from the Rio Vista Field and surrounding fields in the Sacramento Basin was 44.0 MMcfe/d. In 2007, we drilled 27 gross wells of which 23 were successful. We plan to participate in the drilling of 29 wells in 2008.

Rio Vista Field. The Rio Vista Gas Unit and a significant portion of the deep rights below the Rio Vista Gas Unit, which together constitute the greater Rio Vista Field, is the largest onshore natural gas field in California and one of the 15 largest natural gas fields in the United States. The field has produced a cumulative 3.6 Tcfe of natural gas reserves to date since its discovery in 1936. We currently produce from or have behind-pipe reserves in over 14 different zones at depths ranging from 2,000 feet to 11,000 feet in the field. The Rio Vista 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. For the year ended December 31, 2007, the average net daily production in the Rio Vista Field was approximately 40.5 MMcfe/d. We drilled 23 wells in the Rio Vista field in 2007; 20 of these were successful. Six wells drilled in the southern portion of the field were successful in extending areas in two reservoirs, the Lower Capay and the Martinez. This drilling effort was supported by a 12 square mile 3-D seismic program that was shot over the Bradford Island area of the field at the end of 2006. This area of the field had never been covered by 3-D seismic data.

At December 31, 2007, we had one deep rig actively drilling in the field. We secured a second rig at the end of January 2008. We will be procuring a deep rig during the year to drill a deep test under the City of Rio Vista. We plan to participate in the drilling of 20 additional wells in the Rio Vista field in 2008. There are two completion rigs currently working on Rosetta wells in the Rio Vista area. We plan to utilize two to three completion rigs throughout the year. In addition, we plan to conduct between 30 and 40 workover, recompletion or reactivation operations on field wells with these rigs during 2008.

Sacramento Valley Extension. We believe our existing land position and financial strength will give us the ability to continue expanding 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 Forbes stratigraphic traps on the North 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. We have approximately 550 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.

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We drilled four wells in the Sacramento Valley Extension area in 2007, three of these were successful and one was pending completion at year end. Average daily net production for the year ended December 31, 2007 was 3.5 MMcfe/d. We plan to participate in the drilling of 9 additional wells in the Sacramento Valley Extension area in 2008.

Other Activities. We are actively pursuing additional lease and producing property acquisitions throughout the Sacramento Basin. In April 2007, we acquired properties located in the Sacramento Basin from Output Exploration, LLC and OPEX Energy, LLC at a total purchase price of $38.7 million ("OPEX Properties"). The acquisition consisted of 18 producing wells, with net daily production of 3.1 MMcfe/d, and 9.8 BCF of net reserves. We also acquired 4,470 net acres, 112 square miles of 3D seismic and several exploratory prospects in the transaction. The 2008 drilling activity planned for the Sacramento Valley Extension includes five wells that are related to the OPEX Properties, either through our added OPEX acreage or our adjoining acreage, where the improved seismic gained in the OPEX acquisition has helped us identify additional prospects.

Rocky Mountains

At December 31, 2007, we owned approximately 172,000 net acres in the Rocky Mountains. Our production is concentrated in two basins, the DJ and the San Juan Basins. Our average net daily production for the year ended December 31, 2007 was 6.0 MMcfe/d. In 2007, we drilled 89 gross wells of which 75 were successful.

DJ Basin, Colorado. As of December 31, 2007, we had a majority working interest in approximately 109,451 net acres with 125 square miles of 3D seismic data. In 2007, we drilled 70 locations, of which 55 were successful, and identified 49 additional drillable, 3-D seismic supported locations on these lands. To date as of December 31, 2007, we have drilled 134 wells in the developed area of which 114 were successful. For the year ended December 31, 2007, our average net daily production from the DJ Basin was 5.2 MMcfe/d. We have identified over 100 potential drilling locations on our acreage and plan to participate in the drilling of 60 additional wells in 2008 and acquire approximately 29 square miles of additional 3-D seismic data. Pipeline and gathering system construction is expanding in the Republican River, Vernon, SW Wray and Sandy Bluff areas.

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 through the end of October 2004, 11.4 Tcf of which comes from the Fruitland Coal Bed Methane ("CBM"). There is CBM production from depths of 1,600 feet surrounding our leasehold. As of December 31, 2007, we had a 100% working interest position in approximately 12,000 net acres. In 2007, we drilled 19 CBM wells and one saltwater disposal well with all being successful. For the year ended December 31, 2007, our average net daily production from the San Juan Basin was 0.6 MMcfe/d. We have identified 22 drillable locations on our acreage and plan to participate in the drilling of 14 wells in 2008.

Lobo

Lobo Trend. We are a significant producer in the South Texas, Lobo Trend, with approximately 78,000 net acres, 320 square miles of 3-D seismic and approximately 298 operated producing wells. In 2007 and 2006, we added over 10,000 acres adjacent to our acreage and acquired over 80 square miles of 3-D seismic data adding additional drilling inventory. For the year ended December 31, 2007, our average net daily production from the Lobo Trend was 40.8 MMcfe/d. Our working interests range from 50% - 100% but most of our acreage is 100% owned and operated. We have two drilling rigs under contract which should drill 48 wells in 2008. In 2007, we drilled 42 gross wells of which 33 were successful. We have identified over 100 potential drilling locations on our acreage and plan to participate in the drilling of 48 wells in 2008.

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 trend produces from tight sands with low permeabilities and high pressures at depths from 7,500 to 10,000 feet.

Perdido

Perdido Sand Trend. We own a 50% non-operating working interest in approximately 9,000 net acres in the South Texas, Perdido Sand Trend. The Perdido Sands are comprised of tight natural gas sands and are in isolated fault blocks that are stratigraphically trapped below the Upper Wilcox structures at approximately 8,000 to 9,500 feet. The program of horizontal drilling with fracture stimulations has been very successful in maximizing natural gas recovery. We plan to increase our current acreage position of 9,000 net acres and seismic position of 100 square miles and to continue to coordinate with the operator to improve horizontal drilling techniques to lower cost and increase performance. For the year ended December 31, 2007, our average net daily production was 9.5 MMcfe/d from 42 producing wells (19 horizontal and 23 vertical). We participated in the drilling of ten gross wells in 2007 of which all were successful. We have identified over 50 potential drilling locations on our acreage and plan to participate in the drilling of ten wells in 2008.

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State Waters of Texas

Sabine Lake. We own a 50% operated working interest through a joint venture in Sabine Lake, within Texas State Waters of Jefferson County and Louisiana State Waters of Cameron Parish. During 2007, we drilled four gross wells of which three were successful. Facilities and pipelines were constructed and the wells began producing in November and December of 2007 with a net production rate of 13 MMcfe/d at year-end 2007. We currently hold interest in approximately 6,000 net acres with 70 square miles of 3-D seismic data. We are evaluating additional drilling potential in the region for 2008.

Other Onshore

Live Oak County Prospect. Through the interpretation of 3-D seismic data, we identified and participated in the drilling of a 16,500 foot test in Live Oak County, Texas in the fourth quarter of 2007 and tested the well in December 2007. The well is currently being completed with first production expected in the second quarter of 2008. We have identified further opportunities within an Area of Mutual Interest (“AMI”) agreement covering approximately 22,000 gross acres.

In the Other Onshore region, we currently have approximately 26,000 net acres under lease with an average of a 40% non-operated working interest. In 2007, we drilled 18 gross wells of which 16 were successful and are evaluating additional drilling potential in the region for 2008.

Gulf of Mexico

Federal Waters. We own working interests in 12 offshore blocks ranging from 20% to 100% working interest with approximately 36,000 net acres. For the year ended December 31, 2007, our average net daily production from these blocks was 13 MMcfe/d. Under the PTRA with Calpine, we have its full support and the Bankruptcy Court’s order to secure the outstanding MMS ministerial approval for South Pelto 17 and South Timbalier 252. Due to the absence of production, the MMS leases for East Cameron 76 and South Timbalier 235 have expired.

During 2007, three wells previously drilled and completed in 2006 were placed on production in the first half of 2007, of which we own a 25% - 50% working interest. In 2007, as part of our participation in a joint venture, two wells with a 50% non-operated working interest were drilled, resulting in one dry hole and one well pending completion.

We have entered into an AMI agreement in which we have the right to participate in up to a 50% working interest in wells within 150 Outer Continental Shelf (“OCS”) blocks on the Louisiana offshore shelf.

Crude Oil and Natural Gas Operations

Production by Operating Area

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

	For the Year Ended December 31, 2007 (1)		
	Natural Gas (Bcf)	Oil (MBbls)	Equivalents (Bcfe)
California	15.9	24.2	16.1
Rocky Mountains	2.2	5.0	2.2
Mid-Continent	0.2	15.4	0.3

Lobo	14.2	113.3	14.9
Perdido	3.4	18.9	3.5
Texas State Waters	0.8	31.7	1.0
Other Onshore	2.3	131.9	2.9
Gulf of Mexico	3.5	220.8	4.9
	42.5	561.2	45.8

(1) Excludes certain interests in leases and wells not conveyed as part of the Acquisition of the domestic oil and natural gas properties of Calpine, as described in the footnotes for proved reserves below.

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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, 2007, we had 418.4 Bcfe of proved oil and natural gas reserves, including 400.2 Bcf of natural gas and 3,021 MBbls of oil and condensate. Using prices as of December 31, 2007, the estimated standardized measure of discounted future net cash flows was $954.2 million. The following table sets forth by operating area a summary of our estimated net proved reserve information as of December 31, 2007:

	Estimated Proved Reserves at December 31, 2007 (1)(2)(3)			
	Developed (Bcfe)	Undeveloped (Bcfe)	Total (Bcfe)	Percent of Total Reserves
California	107.5	39.4	146.9	35%
Rocky Mountains	35.6	7.0	42.6	10%
Mid-Continent	1.5	0.5	2.0	0%
Lobo	97.9	57.2	155.1	37%
Perdido	10.6	8.4	19.0	5%
Texas State Waters	10.3	-	10.3	2%
Other Onshore	20.4	2.6	23.0	6%
Gulf of Mexico	17.8	1.7	19.5	5%
Total	301.6	116.8	418.4	100%

(1) These estimates are based upon a reserve report prepared by Netherland Sewell & Associates, Inc. (hereafter "Netherland Sewell") using criteria in compliance with the Securities and Exchange Commission ("SEC") guidelines and excludes an estimate of 20 Bcfe of proved oil and natural gas reserves for interests in certain leases and wells being a portion of the properties described in footnote 2 below.

(2) At the July 2005 closing of the Acquisition, we withheld some $75 million for interests in leases and wells (including that portion of the properties subject to the preferential right) which Calpine agreed to transfer legal title to us but for which Calpine had not then secured consents to assign, which consents the parties believed at that time were required.

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

2007 Capital Expenditures

The following table summarizes information regarding development and exploration capital expenditures for the years ended December 31, 2007 and 2006 (Successor), six months ended December 31, 2005 (Successor) and the six months ended June 30, 2005 (Predecessor).

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	Successor			Predecessor
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
			(In thousands)	
Capital Expenditures by Operating Area:				
California	$ 58,493	$ 39,691	$ 3,933	$ 4,572
Rocky Mountains	23,904	15,299	3,035	1,102
Mid-Continent	4,974	3,371	317	220
Lobo	82,665	51,911	6,775	2,020
Perdido	22,636	25,971	9,268	12,441
Texas State Waters	27,000	13,028	3,023	3,417
Other Onshore	24,822	10,207	10,831	2,300
Gulf of Mexico	28,523	17,958	9,369	4,556
Leasehold	8,838	16,383	9,224	2,617
New acquisitions	38,656	35,105	5,524	-
Delay rentals	1,409	728	143	443
Geological and geophysical/seismic	4,422	3,748	5,659	513
Total capital expenditures (1)	$ 326,342	$ 233,400	$ 67,101	$ 34,201

(1) Capital expenditures for the year ended December 31, 2007 (Successor) excludes capitalized internal costs directly identified with acquisition, exploration and development activities of $5.5 million, capitalized interest of $2.4 million and corporate other capital costs of $1.8 million. Capital expenditures for the year ended December 31, 2006 (Successor) excludes capitalized internal costs of $3.4 million, capitalized interest of $2.1 million and corporate other capital costs of $1.7 million. The six months ended December 31, 2005 (Successor) excludes capitalized interest of $0.6 million, corporate other capital costs of $1.6 million and capitalized internal costs of $1.7 million. Corporate other capital costs consist of costs related to IT software/hardware, office furniture and fixtures and license transfer fees. The six-month period ended June 30, 2005 (Predecessor) excludes $(0.7) million of capitalized interest and $1.7 million of overhead.

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, 2007. "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	39,888	32,213	52,547	44,208	179	152
Rocky Mountains	178,393	158,203	18,549	13,525	161	156
Mid-Continent	120	47	9,938	2,575	28	5
Lobo	28,755	31,203	61,949	46,659	248	215
Perdido	14,916	7,385	4,594	2,094	41	20
Texas State Waters	5,706	2,801	10,038	3,193	7	3

Other Onshore	19,689	8,709	44,508	16,905	285	46
Gulf of Mexico (2)	17,495	9,497	46,994	26,886	12	9
	304,962	250,058	249,117	156,045	961	606

(1) This table includes acreage relating to properties for which we believe Calpine is contractually obligated to assist us in resolving, either on the basis of further assurances under the Purchase Agreement and PTRA, or on other legal basis.

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

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The following table shows our interest in undeveloped acreage as of December 31, 2007 which is subject to expiration in 2008, 2009, 2010, and thereafter.

2008		2009		2010		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
36,115	27,229	42,806	35,287	53,309	45,956	172,732	141,586

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.

	Gross Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2007	11.0	7.0	18.0	149.0	28.0	177.0
2006	68.0	15.0	83.0	51.0	8.0	59.0
2005	7.0	5.0	12.0	41.0	3.0	44.0

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

	Net Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2007	7.5	5.1	12.6	130.2	26.5	156.7
2006	58.5	10.0	68.5	45.0	6.2	51.2
2005	3.4	3.4	6.8	23.5	3.0	26.5

Marketing and Customers

Pursuant to our natural gas purchase and sales contract with CES whose term runs through December 2009, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 based on market prices. Calpine maintains a right of first refusal in relation to this dedicated California production for a term of 10 years after December 31, 2009. For the month of December 2007, this dedicated California production comprised approximately 30% 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, provided Calpine has fully cured such payment default, we are obligated under the contract to resume natural gas sales to Calpine. We believe that Calpine’s bankruptcy and their emergence from Bankruptcy has not had a 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 purchase and sales contract, to parties other than Calpine, an affiliate of Calpine is under contract through June 30, 2009 to provide us administrative services in connection with such marketing efforts in accordance with the contract terms.

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

Major Customers

For the year ended December 31, 2007, we had one major customer, Calpine Energy Services (“CES”), which accounted on an aggregated basis for approximately 55% of our consolidated annual revenue.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. 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 federal, state and local government; 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. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Government Regulation

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

Exploration and Production Regulation

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

Environmental and Occupation Regulations

We are subject to extensive federal, state and local statutes, rules and regulations concerning protection of the environment and protection of wildlife; restrictions on the emission or discharge of materials into the environment; and occupational safety and health. We have made and will continue to make expenditures in our efforts to comply with these requirements. In this regard, we believe that we currently hold all up-to-date permits, registrations and other authorizations to the extent they are required by our operations under the current regulatory scheme. We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law.

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.

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Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil and gas reserves with the United States Department of Energy ("DOE") for those properties which we operate. During 2007, we filed estimates of our oil and gas reserves as of December 31, 2006 with the DOE, which differ by five percent or less from the reserve data presented in the Annual Report on Form 10-K for the year ended December 31, 2006. For information concerning proved natural gas and crude oil reserves, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Employees

As of February 18, 2008, we have approximately 152 full time employees. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial, legal and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

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 website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website 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 bankruptcy and certain matters that have survived Calpine's bankruptcy may adversely affect us in several respects.

Calpine, its creditors or interest holders have challenged the fairness of some or all of the Acquisition.

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the "Lawsuit"). The complaint alleges that the purchase by us of the domestic oil and natural gas business formally owned by Calpine (the "Assets") in July 2005 for $1.05 billion, prior to Calpine's declaring bankruptcy, was completed when Calpine was insolvent and was for less than a reasonably equivalent value. Through the Lawsuit, Calpine is seeking (i) monetary damages for the alleged shortfall in value it received for the Assets, which it estimates to be at least approximately $400 million plus interest, or (ii) in the alternative, return of the Assets. We deny and intend to vigorously defend against all claims made by Calpine. The Official Committee of Equity Security Holders and the Official Committee of the Unsecured Creditors both intervened in the Lawsuit for the stated purpose of monitoring the proceedings because these committees claim to have an interest in the Lawsuit, which we dispute because creditors may be paid in full under Calpine's Plan of Reorganization without regard to the Lawsuit and equity holders cannot benefit from fraudulent conveyance actions. On September 10, 2007, we filed a motion to dismiss the complaint, which the Bankruptcy Court heard on October 24, 2007. Following the hearing, the Bankruptcy Court denied our motion on the basis that certain issues we raised in our motion were premature as the bankruptcy process had not yet established how much Calpine's creditors would receive. We filed our answer and counterclaims against Calpine on November 5, 2007. Under Calpine's Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007, the Official Committee of Equity Security Holders was dissolved as of the January 31, 2008 effective date and no longer has any interest in the Lawsuit. While the Unsecured Creditors Committee also officially dissolved as of the same effective date, there are provisions that will allow it to remain involved in lawsuits to which it is a party, which may include this Lawsuit.

The Bankruptcy Court has not set a trial date for the Lawsuit, but the parties are in current agreement that discovery may continue up through April 2008. If after a trial on the merits, the Bankruptcy Court determines that Calpine has met its burden of proof, the Bankruptcy Court could void the transfer or take other actions against us, including (i) setting aside the Acquisition and returning some or all of our purchase price and/or giving us a first lien on all the properties and assets we purchased in the Acquisition or (ii) entering a judgment requiring us to pay Calpine the amount, if any, by which the fair value of the business transferred, as determined by the Bankruptcy Court as of the date of the transaction, exceeded the purchase price determined and paid in July 2005. If the Bankruptcy Court should set aside the Acquisition, it would have a material adverse effect upon our business, results of operations, financial condition or cash flows in that substantially all of the properties received by us at the time of the Acquisition 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 have a material adverse effect upon our results of operation and financial condition depending on the amount we might be required to pay. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

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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 receive under the Purchase Agreement.

On June 20, 2007, Calpine filed with the Bankruptcy Court its proposed Plan of Reorganization and disclosure statement. In the disclosure statement, Calpine revealed that it had not yet made a decision on whether to assume or reject its remaining obligations and duties under the Purchase Agreement, including the interrelated agreements, which set forth the terms and agreements related to Calpine's sale of its oil and gas assets to us. In its proposed supplement to the plan filed on the same date, however, Calpine indicated its desire to assume the NAESB agreements under which Rosetta sells gas to Calpine Energy Services ("CES") and the Calpine Producer Services, L.P. ("CPS") marketing agreement under which CPS provides certain marketing services on our behalf. We contend that all of the transaction documents constitute one agreement in regard to the Acquisition and must, therefore, be assumed or rejected in their entirety as one agreement and will vigorously oppose any effort by Calpine to treat any aspect of the transaction documents as a stand-alone agreement. Following negotiations with Calpine with respect to its Plan of Reorganization and its efforts to assume portions of the Purchase Agreement, we agreed to extend the deadline for Calpine to assume or reject the Purchase Agreement with Rosetta related to the transaction until fifteen days following the conclusion of the Lawsuit. In return, Calpine has agreed not to assume or reject the CPS Marketing Agreement or the NAESB agreements until the conclusion of the litigation with Rosetta; however, if Rosetta prevails in the litigation, Calpine has agreed it will assume the Purchase Agreement and all other agreements from the transaction.

Although Calpine had not made its election to assume or reject the Purchase Agreement, on August 3, 2007, we executed a Partial Transfer and Release Agreement ("PTRA") with Calpine, which was approved by the Bankruptcy Court on September 11, 2007, without prejudice to the other pending claims, disputes, and defenses between Calpine and us. As part of the PTRA, we agreed to enter into a new CPS marketing agreement for a period of two years, effective as of July 1, 2007, and concluding on June 30, 2009; however, the marketing agreement is subject to earlier termination by us upon the occurrence of certain events. In return, Calpine has provided documents to resolve legal title issues as to certain previously purchased oil and gas properties located in the Gulf of Mexico, California and Wyoming ("Properties"). Under the PTRA, we have also agreed to assume all liabilities with respect to those Properties, such as plugging and abandonment, as well as all liabilities and rights associated with any under- or over-payment to the State of California as it relates to certain state land.

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 was to be delivered by Calpine to quiet title related to our ownership of these properties following closing. Those properties that may still be subject to ministerial governmental action approving us as qualified assignee and operator were included as part of the Properties being addressed under the PTRA. For certain other properties, the documentation delivered by Calpine at closing was incomplete. Calpine has not made a decision on whether to perform its remaining obligations under the Purchase Agreement with us and thus perform these required further assurances as to title. On October 30, 2007, the California State Lands Commission approved Calpine's assignment of its interests in a certain State of California lease and certain rights-of-way, completing the transfer of those properties to us and resolving open issues on an audit the State had performed on the properties. We are awaiting the final, ministerial approvals from the Mineral Management Service ("MMS") for the assignment of Calpine's interests in those PTRA Properties for which the federal government is the lessor. The PTRA does not otherwise address the Non-Consent Properties which Calpine withheld from the July 2005 closing due to lack of receipt of the lessors' consents determined at that time (in many instances mistakenly) as needed for transfer and for which we withheld from the closing of the transaction with Calpine approximately $75 million of the purchase price. Until the Purchase Agreement is assumed by Calpine, we will not have record title to the interests in the leases and wells specified in the Purchase Agreement as Non-Consent Properties for which Calpine retained an ownership interest.

The bankruptcy proceeding may continue to prevent, frustrate or delay our ability to receive corrective documentation from Calpine for certain properties that we paid for and bought from Calpine, in cases where Calpine delivered incomplete documentation, including documentation related to certain ministerial governmental approvals.

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 our ownership of these properties. Certain of these properties are subject to ministerial governmental approvals that state we are qualified assignees and operators, 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 we remain hopeful that Calpine will continue to work cooperatively with us to secure these ministerial governmental approvals and accomplish the curative corrections for all of these properties for which we paid Calpine, all of the same being covered, we believe, by the further assurances provision of the Purchase Agreement, that uncertainty remains pending conclusion of the Lawsuit as to the exact details for each property involved and how, when and if this will be able to be secured or accomplished. As noted above, a number of these open issues were addressed under the PTRA between us and Calpine, and we have obtained or are in the process of obtaining proper legal title as to the PTRA Properties.

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Additionally, on June 29, 2006, Calpine filed a Section 365 motion in connection with its pending bankruptcy proceeding seeking entry of an order (which was granted as to the substantial portion of these leases) authorizing Calpine to assume certain oil and natural gas leases which Calpine previously sold or agreed to sell to us in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to us at the time of Calpine's filing for bankruptcy. According to this motion, Calpine filed it to avoid the automatic forfeiture of any interest it might have in these leases by operation of a statutory deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to us or to Calpine. Generally, oil and gas leases are regarded as real property and not leases of real property despite their being called leases. If the Bankruptcy Court were to later conclude that the oil and natural gas leases are "unexpired leases of non-residential real property," and that we had no interest in them, we may be required to take further action or pay further consideration to complete the assignments of these interests or Calpine could retain the leases. In light of Calpine's obligations under the Purchase Agreement and rights afforded purchasers of real property, we would oppose any such request or effort. Any failure by Calpine to complete the corrective action necessary to remove title deficiencies with respect to certain of these properties, including decision of the Bankruptcy Court not to require Calpine to deliver corrective documentation or to require us to pay additional consideration, could result in a material adverse effect on our business, results of operations, financial position or cash flows if we are not able to receive any offsetting refund of the portion of the purchase price attributable to those properties or if the amount of additional consideration we are required to pay is material.

We have expended and may continue to expend significant resources in connection with Calpine's bankruptcy.

We have expended and may continue to expend significant resources in connection with Calpine's bankruptcy. These resources include our increased costs for lawyers, consultant experts and related expenses, as well as lost opportunity costs associated with our dedicating internal resources to these matters. If we continue to expend significant resources and our management is distracted by the Calpine bankruptcy from our business and operational matters, our business, results of operations, financial position or cash flows could be materially adversely affected.

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 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;
- Consumer demand;
- Conservation of resources;
- Regional price differentials and quality differentials of oil and natural gas;

- Domestic and foreign governmental regulations, actions and taxes;
- Political conditions in or affecting other oil producing and natural gas producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- Weather conditions and natural disasters;

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- Technological advances affecting oil and natural gas consumption;
- Overall U.S. and global economic conditions; and
- Price and availability of alternative fuels.

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

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

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

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

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 such as a counterparty experiencing credit default. A default could occur as a result of circumstances relating directly to the counterparty, or due to 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 financial position, results of operations and cash flows. Calpine's recent emergence from bankruptcy reduces the likelihood of failure, but because we have taken the legal position that any rejection by Calpine of the Purchase Agreement, is also a rejection of the parties' natural gas and sales agreements, this could result in the failure of Calpine to continue purchasing natural gas from us.

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 CES whose term runs through December 2009, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 based on market prices. Calpine maintains a right of first refusal for a term of 10 years after December 31, 2009. For the month of December 2007, this dedicated California production comprised approximately 30% of our current overall production based on an equivalent basis. Additionally, under separate monthly spot agreements, we may sell some of our natural gas production to Calpine, which could increase our credit exposure to Calpine. Under the terms of our 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 margin payments one business day in arrears to our collateral account equal to the previous day's natural gas sales. In the event of a default by 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, 2007 would be approximately $3.1 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.

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

Future projects and acquisitions will depend on our ability to obtain financing beyond our cash flow from operations. We may finance our business plan and operations primarily with internally generated cash flow, bank borrowings, entering into exploratory arrangements with other parties and publicly or 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. Additionally, we have secured a written waiver from our lenders in connection with the Lawsuit based on existing events and our belief concerning those events, and have an ongoing obligation to notify our lenders of all significant developments in the Lawsuit. A more detailed description of our credit facilities is included in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” and the footnotes to the Consolidated/Combined Financial Statements.

A breach of any of the covenants imposed on us by the terms of our indebtedness, including the financial covenants and obligations associated with the Lawsuit 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 cancelled as a result of a variety of factors, including:

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

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- Limitations in the market for oil and natural gas.

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

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

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. As noted above, the estimated reserve quantities and present value calculations exclude the estimates attributable to interests in certain leases and wells being a portion of the Non-Consent Properties specified in the Purchase Agreement. The estimated reserve quantities and present value calculations include properties subject to additional documentation, or completion of documentation, including ministerial actions by federal or state agencies for which we believe Calpine is contractually obligated to assist in resolving, along with certain other leases, concerning which Calpine has asserted an ownership interest under its Section 365 motion and order in the Bankruptcy Court. The estimated reserve quantities and present value calculations may be impacted depending on the outcome of the Lawsuit and whether Calpine assumes or rejects the Purchase Agreement. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our engineers control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices, expenditures for future development and exploration activities, engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and natural gas. As an example, Netherland Sewell’s reserve report for year end 2007 includes the downward revision for certain proved undeveloped reserves located in South Texas due to the actual production performance history for wells we have drilled in this area since the Acquisition. 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 MMS, royalty owners and other state and federal regulatory agencies with respect to our affected properties, and will be paid or suspended during the life of the properties based upon oil and natural gas prices as of the date of the estimate. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

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

We are subject to the full cost ceiling limitation which may result in a write-down of our estimated net reserves.

Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated hedge adjusted market prices of oil and gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a write-down if prices increase subsequent to the end of a quarter in which a write-down might otherwise be required. 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. 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.

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For the year ended December 31, 2007, there was no write-down recorded. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a write-down could occur. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates for further information.

Government laws and regulations can change.

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

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

Our success is largely dependent our ability to attract and retain personnel with the skills and experience required for our business. An inability to sufficiently staff our operations or the loss of the services of one or more members of our senior management or of numerous employees with critical skills could have a negative effect on our business, financial position, results of operations, cash flows 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 position, results of operations and 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 the Acquisition, including defense of future litigation and claims involving Calpine's domestic oil and natural gas reserve properties conveyed in the Acquisition, other than certain litigation that Calpine and its subsidiaries retained liability or agreed to indemnify the Company by agreement. Calpine's bankruptcy may affect its obligations for the retained liabilities and 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 at this time 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 position, results of operations and 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 the Gulf of Mexico operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. Under interruptible or short term transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system or for other reasons specified by the particular agreements. We may be required to shut in natural gas wells or delay initial production for lack of a market or because of inadequacy or unavailability of natural gas pipelines or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

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

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

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

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

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

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

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

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

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

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Environmental matters and costs can be significant.

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

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:

- Division 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 unique 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;
- 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.

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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 have 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.

We have also entered into a series of interest rate swap agreements to hedge the change in the variable interest rates associated with our debt under our credit facility. If interest rates should fall below the rate established in the hedge, we could be exposed to losses associated with these hedges.

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.

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 and indemnify us for certain liabilities. Third parties may seek to hold us responsible for some or all of those 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 Agreement to obtain payment from them. We are exposed to the risk that, in these circumstances and in light of the Lawsuit, 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 and the PTRA, 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. Some of the required permits, licenses and approvals have been obtained or received, but certain others remain outstanding. In connection with the PTRA, we have submitted the required documents and are waiting for ministerial approvals from the MMS. If we are unable to obtain a reissuance or issuance of any contract, license or permit being transferred or the required approvals as operator and/or lessee, as to certain oil and gas properties, our business and results of operations, financial position and cash flows could be adversely affected.

The 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 not advised us of any change in the inactive status of the SEC's informal inquiry in this regard. Our understanding is that Calpine 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.

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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.

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, 2007, 50,998,073 shares of common stock were issued, including 899,150 shares of restricted stock issued to certain employees and directors. The majority of these shares vest over a three year period. Of the restricted stock that has been granted, 443,725 shares had vested as of December 31, 2007 and the remaining shares will vest no later than 2012. 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. In addition, we have issued 1,062,600 options to purchase common stock issued to certain employees and directors, of which 90,000 have been exercised as of December 31, 2007. The potential issuance of 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 located 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 were assigned a lease by Calpine and consequently deal directly with the landlord. We also have field offices in Laredo, Texas, Rio Vista, California and Magnolia, Arkansas. All leases were negotiated at market prices applicable to their respective location.

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Title to Properties

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

Except as noted below in the “Open Issues Regarding Legal Title to Certain Properties” section in Item 3. Legal Proceedings, 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 Lawsuit and its possible rejection of the Purchase Agreement may delay or frustrate our ability to complete additional transfers of properties for which legal title was not obtained or secure curative documentation to correct possible clouds on title as of July 7, 2005. See item 3. Legal Proceedings for further information concerning the Lawsuit and Calpine’s possible rejection of the Purchase Agreement, and the effect of possible losses in connection with open issues regarding legal title to certain properties.

Item 3. Legal Proceedings

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

Calpine Bankruptcy

On December 20, 2005, Calpine and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (the “Bankruptcy Court”). On December 19, 2007, the Bankruptcy Court approved Calpine’s Plan of Reorganization. On January 31, 2008, Calpine and certain of its subsidiaries emerged from Bankruptcy.

Calpine’s Lawsuit Against Rosetta

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the “Lawsuit”). The complaint alleges that the purchase by Rosetta of the domestic oil and natural gas business owned by Calpine (the “Assets”) in July 2005 for $1.05 billion, prior to Calpine filing for bankruptcy, was completed when Calpine was insolvent and was for less than a reasonably equivalent value. Through the Lawsuit, Calpine is seeking (i) monetary damages for the alleged shortfall in value it received for these Assets which it estimates to be at least approximately $400 million plus interest, or (ii) in the alternative, return of the Assets from us. We believe that the allegations in the Lawsuit are without merit, and we continue to believe that it is unlikely that this challenge by Calpine to the fairness of the Acquisition will be successful upon the ultimate disposition of this litigation in the Bankruptcy Court, or if necessary, in the appellate courts. The Official Committee of Equity Security Holders and the Official Committee of the Unsecured Creditors both intervened in the Lawsuit for the stated purpose of monitoring the proceedings because the committees claimed to have an interest in the Lawsuit, which we dispute because we believe creditors may be paid in full under Calpine’s Plan of Reorganization without regard to the Lawsuit and equity holders have no interest in fraudulent conveyance actions. Under Calpine's Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007, the Official Committee of Equity Security Holders was dissolved as of the January 31, 2008 effective date and no longer has any interest in the Lawsuit. While the Unsecured Creditors Committee also was officially dissolved as of the same effective date, there are provisions under the approved Plan of Reorganization that will allow it to remain involved in lawsuits to which it is a party, which may include this Lawsuit.

On September 10, 2007, we filed a motion to dismiss the Lawsuit or in the alternative, to stay the Lawsuit. The Bankruptcy Court conducted a hearing upon our motion on October 24, 2007. Following the hearing, the Bankruptcy Court denied our motion on the basis that certain issues we raised in our motion were premature as the bankruptcy process had not yet established how much Calpine's creditors would receive. On November 5, 2007, we filed our answer, affirmative defenses and counterclaims with respect to the Lawsuit, denying the allegations set forth in both counts of the Lawsuit, and asserting affirmative defenses to Calpine's claims as well as affirmative counterclaims against Calpine related to the Acquisition for (i) breach of covenant of solvency, (ii) fraud and fraud in a real estate transaction, (iii) breach of contract, (iv) conversion, (v) civil theft and (vi) setoff. The parties are currently in agreement that discovery may continue in the Lawsuit until April 2008. The Bankruptcy Court has not set a trial date for the lawsuit.

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Remaining Issues with Respect to the Acquisition

Separate from the Calpine lawsuit, Calpine has taken the position that the Purchase and Sale Agreement and interrelated agreements concurrently executed therewith, dated July 7, 2005, by and among Calpine, us, and various other signatories thereto (collectively, the "Purchase Agreement") are "executory contracts", which Calpine may assume or reject. Following the July 7, 2005 closing of the Acquisition and as of the date of Calpine's bankruptcy filing, there were open issues regarding legal title to certain properties included in the Purchase Agreement. On September 25, 2007, the Bankruptcy Court approved Calpine's Disclosure Statement accompanying its proposed Plan of Reorganization under Chapter 11 of the Bankruptcy Code, in which Calpine revealed it had not yet made a decision as to whether to assume or reject its remaining duties and obligations under the Purchase Agreement. We may contend that the Purchase Agreement is not an executory contract which Calpine may choose to reject. If the Court were to determine that the Purchase Agreement is an executory contract, we may contend the various agreements entered into as part of the transaction constitute a single contract for purposes of assumption or rejection under the Bankruptcy Code, and we may argue that Calpine cannot choose to assume certain of the agreements and to reject others. This issue may be contested by Calpine. If the Purchase Agreement is held to be executory, the deadline by when Calpine must exercise its decision to assume or reject the Purchase Agreement and the further duties and obligations required therein would normally have been the date on which Calpine's Plan of Reorganization was confirmed; however, in order to address certain issues, we and Calpine have agreed to extend this deadline until fifteen days following the entry of a final, unappealable order in the Lawsuit, and the parties set forth this agreement in the proposed Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007.

Open Issues Regarding Legal Title to Certain Properties

Under the Purchase Agreement, Calpine is required to resolve the open issues regarding legal title to interests in certain properties. At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to leases and wells identified by Calpine as requiring third-party consents or waivers of preferential rights to purchase that were not received by the parties before closing ("Non-Consent Properties"). The interests in the Non-Consent Properties were not included in the conveyances delivered at the closing. Subsequent analysis determined that a significant portion of the Non-Consent Properties did not require consents or waivers. For that portion of the Non-Consent Properties for which third-party consents were in fact required and for which either us or Calpine obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, we contend Calpine was and is obligated to have transferred to us the record title, free of any mortgages and other liens.

The approximate allocated value under the Purchase Agreement for the portion of the Non-Consent Properties subject to a third-party's preferential right to purchase is $7.4 million. We have retained $7.1 million of the purchase price under the Purchase Agreement for the Non-Consent Properties subject to the third-party preferential right, and, in addition, a post-closing adjustment is required to credit us for approximately $0.3 million for a property which was transferred to us but, if necessary, will be transferred to the appropriate third party under its exercised preferential purchase right upon Calpine's performance of its obligations under the Purchase Agreement.

We believe all conditions precedent for our receipt of record title, free of any mortgages or other liens, for substantially all of the Non-Consent Properties (excluding that portion of these properties subject to the third-party preferential right) were satisfied earlier, and certainly no later, than December 15, 2005, when we tendered the amounts necessary to conclude the settlement of the Non-Consent Properties.

We believe we are the equitable owner of each of the Non-Consent Properties for which Calpine was and is obligated to have transferred the record title and that such properties are not part of Calpine's bankruptcy estate. Upon our receipt from Calpine of record title, free of any mortgages or other liens, to these Non-Consent Properties (excluding that portion of these properties subject to a validly exercised third party’s preferential right to purchase) and further assurances required to eliminate any open issues on title to the remaining properties discussed below, we have been prepared to conclude the remaining aspects of the Acquisition. We have not included in our statement of operations for the years ended December 31, 2007 and 2006 and six months ended December 31, 2005, estimated net revenues and related estimated production from interests in certain leases and wells being a portion of the Non-Consent Properties, including those properties subject to preferential rights.

On September 11, 2007, the Bankruptcy Court entered an order approving that certain Partial Transfer and Release Agreement (“PTRA”) negotiated by and between us and Calpine which, among other things, resolves issues in regard to title of certain of the other oil and natural gas properties we purchased from Calpine in the Acquisition and for which payment was made to Calpine on July 7, 2005, and we entered into a new Marketing and Services Agreement (“MSA”) with Calpine Producer Services, L.P. (“CPS”) for a two-year period commencing on July 1, 2007 but which is subject to earlier termination by us on the occurrence of certain events. The additional documentation received from Calpine under the PTRA eliminates any open issues in our title and resolves any issues as to the clarity of our ownership in certain properties located in the Gulf of Mexico, California, and Wyoming (the “PTRA Properties”), including all oil and gas properties requiring ministerial approvals, such as leases with the U.S. Minerals Management Service (“MMS”), California State Lands Commission (“CSLC”) and U.S. Bureau of Land Management (“BLM”). However, the PTRA was executed without prejudice to Calpine’s fraudulent conveyance action or its right, if any, to reject the Purchase Agreement, and without prejudice to our rights and legal arguments in relation thereto, including our various counterclaims. The PTRA did not otherwise address or resolve issues with respect to the Non-Consent Properties and certain other properties.

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We recorded the conveyances of those PTRA Properties in California not requiring governmental agency approval. On October 30, 2007, the CSLC approved the assignment of the State of California leases and rights of way to us from Calpine and resolved open issues under an audit the State of California had conducted as to these properties. While the documentation has been filed with the MMS, we are still awaiting its ministerial approval for the assignment of Calpine's interests in MMS Federal Offshore leases for South Pelto 17 and South Timalier 252 to us.

Notwithstanding the PTRA, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively as to the remaining outstanding issues under the Purchase Agreement. If Calpine does not fulfill its contractual obligations (as a result of rejection of the Purchase Agreement or otherwise) and does not complete the documentation necessary to resolve these remaining issues whether under the Purchase Agreement or the PTRA, 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 unlikely upon ultimate disposition, including appeals, if any, then we could experience losses which could have a material adverse effect on our business, financial condition, statement of operations or cash flows.

Sale of Natural Gas to Calpine

In addition to the issues involving legal title to certain properties, we executed, as part of the interrelated agreements that constitute the Purchase Agreement, certain natural gas sales agreements with Calpine Energy Services, L.P. ("CES"), which also filed for bankruptcy on December 20, 2005. During the period following Calpine's filing for bankruptcy, CES has continued to make the required deposits into our margin account and to timely pay for natural gas production it purchases from our subsidiaries under these various natural gas sales agreements. Although Calpine has indicated in a supplement to its recently proposed Plan of Reorganization that it intends to assume the CES natural gas sales agreements with us, we disagree that Calpine may assume anything less than the entire Purchase Agreement and intend to oppose any effort by Calpine to do less.

Calpine's Marketing of the Company's Production

As part of the PTRA, we entered into the MSA with CPS, effective July 1, 2007, which was approved by the Bankruptcy Court on September 11, 2007. Under the MSA, CPS provides marketing and related services in relation to the sales of our natural gas production and charges us a fee. This MSA extends CPS' obligations to provide such services until June 30, 2009. The MSA is subject to early termination by us upon the occurrence of certain events.

Events within Calpine's Bankruptcy Case

On June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding in the Bankruptcy Court seeking the entry of an order authorizing Calpine to assume certain oil and natural gas leases that Calpine had previously sold or agreed to sell to us in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to us at the time of Calpine's filing for bankruptcy. The oil and gas leases identified in Calpine's motion are, in large part, those properties with open issues in regards to their legal title in certain oil and natural gas leases which Calpine contends it may possess some legal interest. According to this motion, Calpine filed its pending bankruptcy proceeding in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a bankruptcy code deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to us or Calpine, but we understand Calpine's motion was meant to allow Calpine to preserve and avoid forfeiture under the Bankruptcy Code of whatever interest Calpine may possess, if any, in these oil and natural gas leases. We dispute Calpine's contention that it may have an interest in any significant portion of these oil and natural gas leases and intend to take the necessary steps to protect all of the our rights and interest in and to the leases. Certain of these properties have been subsequently addressed under the PTRA discussed above.

On July 7, 2006, we filed an objection in response to Calpine's motion, wherein we asserted that oil and natural gas leases constitute interests in real property that are not subject to "assumption" under the Bankruptcy Code. In the objection, we also requested that (a) the Bankruptcy Court eliminate from the order certain Federal offshore leases from the Calpine motion because these properties were fully conveyed to us in July 2005, and the MMS has subsequently recognized us as owner and operator of all but two of these properties, two other leases of offshore properties having expired, and (b) any order entered by the Bankruptcy Court be without prejudice to, and fully preserve our rights, claims and legal arguments regarding the characterization and ultimate disposition of the remaining described oil and natural gas properties. In our objection, we also urged the Bankruptcy Court to require the parties to promptly address and resolve any remaining issues under the pre-bankruptcy definitive agreements with Calpine and proposed to the Bankruptcy Court that the parties could seek mediation to complete the following:

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- Calpine's conveyance of its retained interest in the Non-Consent Properties to us;
- Calpine's execution of all documents and performance of all tasks required under "further assurances" provisions of the Purchase Agreement with respect to certain of the oil and natural gas properties for which we have already paid Calpine; and
- Resolution of the final amounts we are to pay Calpine.

At a hearing held on July 12, 2006, the Bankruptcy Court took the following steps:

- In response to an objection filed by the Department of Justice and asserted by the CSLC that the Debtors' Motion to Assume Non-Residential Leases and Set Cure Amounts (the "Motion"), did not allow adequate time for an appropriate response, Calpine withdrew from the list of oil and gas leases that were the subject of the Motion those leases issued by the United States (and managed by the MMS) (the "MMS Oil and Gas Leases") and the State of California (and managed by the CSLC) (the "CSLC Leases"). Calpine, the Department of Justice and the State of California agreed to an extension of the existing deadline to November 15, 2006 to assume or reject the MMS Oil and Gas Leases and CSLC Leases under Section 365 of the Bankruptcy Code, to the extent the MMS Oil and Gas Leases and CSLC Leases are leases subject to Section 365. The effect of these actions was to render our objection inapplicable at that time; and
- The Bankruptcy Court also encouraged Calpine and us to arrive at a business solution to all remaining issues including approximately $68 million payable to Calpine for conveyance of the Non-Consent Properties (excluding the properties subject to third party's preferential right).

On August 1, 2006, we filed a number of proofs of claim in the Calpine bankruptcy asserting claims against a variety of Calpine debtors seeking recovery of $27.9 million in liquidated amounts, as well as unliquidated damages in amounts that have not presently been determined. In the event that Calpine elects to reject the Purchase Agreement or otherwise refuses to perform its remaining obligations therein, we anticipate we will be allowed to amend our proofs of claim to assert any additional damages we suffer as a result of the ultimate impact of Calpine's refusal or failure to perform under the Purchase Agreement. In the bankruptcy, Calpine may elect to contest or dispute the amount of damages we seek in our proofs of claim. We will assert all right to offset any of our damages against any funds we possess that may be owed to Calpine. Until the allowed amount of our claims are finally established and the Bankruptcy Court issues its rulings with respect to Calpine's approved Plan of Reorganization, we can not predict what amounts we may recover from the Calpine bankruptcy should Calpine reject or refuse to perform under the Purchase Agreement.

With respect to the stipulations between Calpine and MMS and Calpine and CSLC extending the deadline to assume or reject the MMS Oil and Gas Leases and the CSLC Leases respectively, these parties further extended this deadline by stipulation. The deadline was first extended to January 31, 2007, was further extended to April 15, 2007 with respect to the MMS Oil and Gas Leases and April 30, 2007 with respect to the CSLC Leases, was further extended again to September 15, 2007 with respect to the MMS Oil and Gas Leases and July 15, 2007 and more recently, October 31, 2007 with respect to the CSLC Leases. The Bankruptcy Court entered Orders related to the MMS Oil and Gas Leases and CSLC Leases which included appropriate language that we negotiated with Calpine for our protection in this regard. The MMS Oil and Gas Leases and CSLC Leases were included in the PTRA that was approved by the Bankruptcy Court on September 11, 2007, with the result that there is no further need for the parties to contest whether the MMS Oil and Gas Leases and the CLSC Leases are appropriate for inclusion in Calpine's 365 motion. The PTRA approved by the Bankruptcy Court, among other things, resolves open issues in regard to our title to ownership of all of the unexpired MMS Oil and Gas Leases and the CLSC Leases. However, the PTRA was executed without prejudice to Calpine's fraudulent conveyance action or its rights, if any, to reject the Purchase Agreement and our rights and legal arguments in relation thereto.

On June 20, 2007, Calpine filed its proposed Plan of Reorganization and Disclosure Statement with the Bankruptcy Court. Calpine had indicated in its filings with the Court that it believed substantial payments in the form of cash or newly issued stock, or some combination thereof, would be made to unsecured creditors under its proposed Plan of Reorganization that could conceivably result in payment of 100% of allowed claims and possibly provide some payment to its equity holders. The amounts any plan ultimately distributes to its various claimants of the Calpine estate, including unsecured creditors, will depend on the amount of allowed claims that remain following the objection process. The Bankruptcy Court approved Calpine's Plan of Reorganization on December 19, 2007, overruling our objection to the releases granted by this Plan to prior and current directors and officers of Calpine and certain of its law firms and other professional advisors.

On August 3, 2007, we executed the PTRA, resolving certain open issues without prejudice to Calpine's avoidance action and, if the Court concludes the Purchase Agreement is executory, Calpine's ability to assume or reject the Purchase Agreement. The principal terms are as follows:

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- We entered into a new MSA with CPS through and until June 30, 2009, effective July 1, 2007. This agreement is subject to earlier termination right by us upon the occurrence of certain events;

- Calpine delivers to us documents that resolve title issues pertaining to the Properties defined as certain previously purchased oil and gas properties located in the Gulf of Mexico, California and Wyoming;

- We assume all Calpine's rights and obligations for an audit by the California State Lands Commission on part of the Properties; and

- We assume all rights and obligations for the Properties, including all plugging and abandonment liabilities.

On September 11, 2007, the Bankruptcy Court approved the PTRA. The PTRA did not resolve the open issues on the Non-Consent Properties and certain other properties.

Notwithstanding the PTRA, as a result of Calpine’s bankruptcy, there remains the possibility that there will be issues between us and Calpine that could amount to material contingencies in relation to the litigation filed by Calpine against us or the Purchase Agreement, including unasserted claims and assessments with respect to (i) the still pending 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 Purchase Agreement and PTRA; and (iii) the issues pertaining to the Non-Consent Properties.

Arbitration between Calpine/Rosetta and Pogo Producing Company

On September 1, 2004, Calpine and Calpine Natural Gas L.P. sold their New Mexico oil and natural gas assets to Pogo Producing Company (“Pogo”). During the course of that sale, Pogo made three title defect claims on properties sold by Calpine (valued at approximately $2.7 million in the aggregate, subject to a $0.5 million deductible assuming no reconveyance) claiming that certain leases subject to the sale had expired because of lack of production. With Rosetta’s assistance, Calpine had undertaken without success to resolve this matter by obtaining ratifications of a majority of the questionable leases. Calpine filed for bankruptcy protection before Pogo filed arbitration against it. Even though this is a retained liability of Calpine, Calpine had earlier declined to accept the Company’s tender of defense and indemnity when Pogo filed for arbitration against us. We filed a motion to stay this arbitration under the automatic stay provision of the Bankruptcy Code which motion was granted by the Bankruptcy Court on April 24, 2007. We intend to cooperate with Calpine in defending against Pogo’s claim should it resume; however, it is too early for management to determine whether this matter will affect us, and if so, in what amount. This is due, but not limited to uncertainity concerning (1) whether or not Pogo’s proofs of claim will be fully satisfied by Calpine under its approved Plan of Reorganization; and (2) whether and if so, the extent to which, Calpine may reimburse us for our claim for our defense costs and any arbitration award regarding the Pogo claim.

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 2007.

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Part II

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

Trading Market

Our common stock is listed on The NASDAQ Global Select Market® under the symbol "ROSE". Our common stock began publicly trading on February 13, 2006. 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.

The following table sets forth for the 2007 and 2006 periods indicated the high and low sale prices of our common stock:

2007	High	Low	2006	High	Low
January 1 - March 31	$ 21.07	$ 17.66	February 13 - March 31	$ 18.75	$ 17.67
April 1 - June 30	25.00	20.74	April 1 - June 30	21.48	15.81
July 1 - September 30	21.97	15.67	July 1 - September 30	19.05	15.82
October 1 - December 31	20.84	17.69	October 1 - December 31	19.89	16.71

The number of shareholders of record on February 18, 2008 was 10,912. 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.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2007:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs
October 1 - October 31	1,404	$ 18.60	-	-
November 1 - November 30	2,381	18.49	-	-
December 1 - December 31	82	17.93	-	-

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

Stock Performance Graph

The following stock performance graph compares our common stock performance ("ROSE") with the performance of the Standard & Poors' 500 Stock Index ("S&P 500 Index") and the performance of our peers within the oil and gas industry. The seven companies that comprise our peer group are Petrohawk Energy Corporation ("HK"), St. Mary Land & Exploration Co. ("SM"), Bill Barrrett Corp. ("BBG"), Brigham Exploration Co. ("BEXP"), Berry Petroleum Co. ("BRY"), Comstock Resources Inc. ("CRK") and Range Resources Corp. ("RRC"), all known as our peer group ("Peer Group"). The graph assumes the value of the investment in our common stock , the S&P 500 Index, and our Peer Group was $100 on February 13, 2006 and that all dividends are reinvested.

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Total Return Among Rosetta Resources Inc., the S&P 500 Index and our Peer Group

	2/13/2006 (1)	12/31/2006	12/31/2007
ROSE	$ 100.00	$ 98.26	$ 104.37
S&P 500 Index	$ 100.00	$ 111.94	$ 115.89
Peer Group	$ 100.00	$ 94.82	$ 128.62

(1) February 13, 2006 was the first full trading day following the effective date of the Company's registration statement filed in connection with the public offering of its common stock.

Item 6. Selected Financial Data

The following table sets forth our selected financial data. For the years ended December 31, 2007 and 2006 and the six months ended December 31, 2005 (Successor), the financial data has been derived from the consolidated financial statements of Rosetta Resources Inc. For the six months ended June 30, 2005 and for the years ended December 31, 2004 and 2003 (Predecessor), the financial data was derived from the combined financial statements of the domestic oil and natural gas properties of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and natural gas business. You should read the following selected historical consolidated/combined financial data in connection with "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.

Additionally, the historical financial data reflects successful efforts accounting for oil and natural gas properties for the Predecessor periods described above and the full cost method of accounting for oil and natural gas properties effective July 1, 2005 for the Successor periods. In addition, Calpine adopted on January 1, 2003, Statement of Financial Accounting Standards ("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") to measure the cost of employee services received in exchange for an award of equity instruments, whereas we adopted the intrinsic value method of accounting for stock options and stock awards pursuant to Accounting Principles Board Opinion No. 25, "Stock Issued to Employees" ("APB No. 25") effective July 2005, and as required have adopted the guidance for stock-based compensation under SFAS No. 123 (revised 2004) "Share-Based Payments" ("SFAS No. 123R") effective January 1, 2006.

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	Successor-Consolidated			Predecessor - Combined		
	Year Ended December 31,		Six Months Ended December 31,	Six Months Ended June 30,	Year Ended December 31,	
	2007	2006	2005	2005	2004 (1)	2003 (1)
	(In thousands, except per share data)					
Operating Data:						
Total revenue	$ 363,489	$ 271,763	$ 113,104	$ 103,831	$ 248,006	$ 279,916
Income (loss) from continuing operations (2)	57,205	44,608	17,535	18,681	(78,836)	66,879
Net income (loss) (2)	57,205	44,608	17,535	18,681	(10,396)	71,440
Income per share (2):						
Income (loss) from continuing operations						
Basic	1.14	0.89	0.35	0.37	(1.58)	1.34
Diluted	1.13	0.88	0.35	0.37	(1.58)	1.33
Net income (loss)						
Basic	1.14	0.89	0.35	0.37	(0.21)	1.43
Diluted	1.13	0.88	0.35	0.37	(0.21)	1.42
Cash dividends declared per common share	-	-	-	-	-	-
Balance Sheet Data (At the end of the Period)						
Total assets	1,357,214	1,219,405	1,119,269	-	656,528	990,893
Long-term debt	245,000	240,000	240,000	-	-	507
Stockholders' equity/owner's net investment	872,955	822,289	715,423	-	223,451	233,847

(1) In September 2004, Calpine and Calpine Natural Gas L.P. sold their natural gas reserves in the New Mexico San Juan Basin and Colorado Piceance Basin and such properties have been reflected as discontinued operations for the respective periods presented herein.

(2) Includes a $202.1 million pre-tax impairment charge for the year ended December 31, 2004.

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

Overview

We are 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. We own producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Rocky Mountains, the Lobo and Perdido Trends in South Texas, the State Waters of Texas and the Gulf of Mexico and other properties located in various geographical areas in the United States. 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 adopted the full cost method of accounting for our oil and natural gas properties, (see "Critical Accounting Policies and Estimates—Oil and Gas Activities" below for further discussion of the differences on the Consolidated/Combined Financial Statements of the two accounting methods).

We plan our activities and budget based on conservative sales price assumptions given the inherent volatility of oil and natural gas prices that are influenced by many factors beyond our control. We focus our efforts on increasing oil and 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 the fair market value of hedges we executed to mitigate the volatility in the changes of oil and natural gas prices in future periods. These instruments meet the criteria to be accounted for as cash flow hedges, and 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. In addition, we have also entered into a series of interest rate swap agreements to hedge the change in variable interest rates associated with our debt under our credit facility. In periods where interest rates rise, these hedges will mitigate losses to future earnings. In periods of falling interest rates, these hedges will expose us to losses in future earnings.

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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 adding reserves through drilling and acquisitions, while placing a clear priority on lowering the Company's cost of replacing reserves. Consistent with our stated strategies, we will emphasize building a high-quality inventory of future drilling projects while also focusing on improving our capital and cost efficiency. We have several efforts underway to address this challenge.

We have set a goal to fully assess our existing asset portfolio during 2008. We will implement a formal capital performance lookback process to monitor where value is being created. In addition, we will form technical teams to study the resource potential of our current assets, many of which we believe may yield significant future drilling inventory through down-spacing programs, deeper or shallower programs or close extensions. The combination of more inventory and calibration on our programs from the lookback exercise should allow us to deliver better performance on our future capital spending.

We also expect to launch several of significant resource assessments in basins, trends, or plays where significant inventory can be identified. We are considering several areas where we have technical expertise that could be applied to new or extension opportunities. This effort will service existing asset optimization as well as our merger and acquisition efforts.

Finally, we will undertake to improve our capital and cost efficiency on an ongoing business. We will look for opportunities to attract additional experienced personnel with successful track records, streamline or improve processes and organize for profitable growth. In addition to the capital lookback process, we expect to bolster several other core analytic functions, including reserve engineering, business analysis and planning.

Financial Highlights

Our consolidated financial statements reflect total revenue of $363.5 million on total volumes of 45.8 Bcfe for the year ended December 31, 2007 (Successor). Operating income was $106.6 million, or 29% of total revenue, and included lease operating expense of $47.0 million and $6.8 million of compensation expense for stock-based compensation granted to employees. Total net other income was comprised of interest expense (net of capitalized interest) on our long-term debt offset by interest income on short term cash investments. Overall, our net income for the year ended December 31, 2007 (Successor) was $57.2 million, or 16% of total revenue.

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, related disclosure of contingent assets and liabilities and proved oil and gas reserves. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements and those of our Predecessor. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8. Consolidated Financial Statements and Supplementary Data Note 3, Summary of Significant Accounting Policies, for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Activities

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

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Full Cost Method

We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into a cost center (the amortization base), whether or not the activities to which they apply are successful. As all of our operations are located in the U.S., all of our costs are included in one cost pool. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that directly relate to our oil and gas activities. Interest costs related to unproved properties are also capitalized. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment rather than amortization. Upon evaluation, these costs are transferred to the full cost pool and amortized. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities, as used by our Predecessor, and as presented herein for the six months ended June 30, 2005, since we 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.

Proved Oil and Gas Reserves

Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently, provided to Netherland Sewell who then generates an annual year-end reserve report. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impact property, plant and equipment amounts in the balance sheets and the depreciation, depletion and amortization amounts in the consolidated/combined statement of operations. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Full Cost Ceiling Limitation

Our ceiling test computation was calculated using hedge adjusted market prices at December 31, 2007, which were based on a Henry Hub price of $6.80 per MMBtu and a West Texas Intermediate oil price of $92.50 per Bbl (adjusted for basis and quality differentials). The use of these prices would have resulted a pre-tax writedown of $21.5 million at December 31, 2007. However, we reevaluated our ceiling test exposure on February 22, 2008 using the market price for Henry Hub of $8.91 per MMBtu and the price for West Texas Intermediate $98.88 per Bbl. Utilizing these prices, the calculated ceiling amount exceeded our net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the year ended December 31, 2007. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a write-down could occur.

There was no ceiling test write-down for the year ended December 31, 2006 or for the six months ended December 31, 2005.

Depreciation, Depletion and Amortization

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future depletion expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test write-down. A five percent positive or negative revision to proved reserves throughout the Company would decrease or increase the depreciation, depletion and amortization ("DD&A") rate by approximately $0.18 to $0.19 per MMcfe. This estimated impact is based on current data at December 31, 2007 and actual events could require different adjustments to DD&A.

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Derivative Transactions and Hedging Activities

We enter into derivative transactions to hedge against changes in oil and natural gas prices and changes in interest rates related to outstanding debt under our credit agreements primarily through the use of fixed price swap agreements, basis swap agreements, costless collars and put options. Consistent with our hedge policy, we entered into a series of derivative transactions to hedge a significant portion of our expected natural gas production through 2009. We also entered into a series of interest rate swap agreements to hedge the change in interest rates associated with our variable rate debt through June of 2009. These transactions are recorded in our financial statements in accordance with 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 changes in interest rates and thereby achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with SFAS No. 133, as amended, all derivative instruments, unless designated as normal purchase normal sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash 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 quarterly, consistent with our documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges are included in other income (expense).

Future Development and Abandonment Costs

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

We provide for future abandonment costs in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations". This standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

Stock -Based Compensation

We account for stock-based compensation in accordance with SFAS 123R. Under the provisions of SFAS 123R, stock-based compensation cost is estimated at the grant date based on the award's fair value as calculated by the

Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

Revenue Recognition

The Company uses the sales method of accounting for the sale of its natural gas. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At December 31, 2007 and 2006, imbalances were insignificant.

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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. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Royalties Payable on the Company’s Consolidated Balance Sheet.

Income Taxes

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with SFAS No. 109, “Accounting for Income Taxes”. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income and change in stockholder ownership that would trigger limits on use of net operating losses under the Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years. Our NOLs are more fully described in Item 8. Consolidated Financial Statements and Supplementary Data, Note 13 Income Taxes.

Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense by approximately $1.0 million for the year ended December 31, 2007.

FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109” (“FIN 48”) requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent Accounting Developments

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the Financial Accounting Standards Board (“FASB”) issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160), which improves the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of SFAS No. 160 to have a material impact on our consolidated financial position, results of operations or cash flows.

Business Combinations. In December 2007, FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141R"), which creates greater consistency in the accounting and financial reporting of business combinations. This statement is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of SFAS No. 141R to have a material impact on the our consolidated financial position, results of operations or cash flows.

The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, FASB issued SFAS No. 159, "The Fair Value Option For Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115" ("SFAS No. 159"), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of SFAS No. 159 to have a material impact on our consolidated financial position, results of operations or cash flows as we did not choose to measure at fair value.

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Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157,"Fair Value Measurements" ("SFAS No. 157"), which addresses how companies should measure fair value when companies are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles ("GAAP"). As a result of SFAS No. 157, there is now a common definition of fair value to be used throughout GAAP. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The FASB has also issued Staff Position FAS 157-2 ("FSP No. 157-2"), which delays the effective date of SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We do not expect the adoption of SFAS No. 157 or FSP No. 157-2 to have a material impact on our consolidated financial position, results of operations or cash flows.

Results of Operations

The following table summarizes our results of operations and compares the year ended December 31, 2007 to the year ended December 31, 2006. However, due to the acquisition of Calpine Natural Gas L.P. in July 2005, the year ended December 31, 2006 financial data is not comparative with 2005. As such, 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.

Differences in accounting principles also exist between Calpine and us, primarily the full cost method of accounting for oil and natural gas properties adopted by us and the successful efforts method of accounting for oil and natural gas properties followed by Calpine. In addition, Calpine adopted on January 1, 2003, SFAS No. 123 to measure the cost of employee services received in exchange for an award of equity instruments at fair value, whereas we adopted the intrinsic value method of accounting for stock options and stock awards effective July 1, 2005, and as required, have adopted the guidance for stock-based compensation under SFAS No. 123R effective January 1, 2006. See Note 3 to the Consolidated/Combined Financial Statements for further discussion regarding the adoption of SFAS 123R.

We believe comparative results would be misleading for the year ended December 31, 2006 and 2005; therefore, we have presented the information below separately as Successor and Predecessor. In addition, at the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to interest in leases and wells associated with the Non-Consent Properties. Our operating income does not include our estimated revenues and expenses related to certain interests in leases and wells being a portion of the Non-Consent Properties, which were a part of the Predecessor's operating income.

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
Total revenues (In thousands)	$ 363,489	$ 271,763	$ 113,104	$ 103,831
Production:				
Gas (Bcf)	42.5	30.3	12.4	14.5
Oil (MBbls)	561.2	551.3	185.6	163.8
Total Equivalents (Bcfe)	45.8	33.4	13.5	15.5
$ per unit:				
Avg. Gas Price per Mcf	$ 7.61	$ 7.81	$ 8.23	$ 6.59

Avg. Gas Price per Mcf excluding Hedging		7.07		6.83		9.57		-
Avg. Oil Price per Bbl		71.54		64.01		59.52		49.86
Avg. Revenue per Mcfe	$	7.94	$	8.14	$	8.38	$	6.70

Revenues

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

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Year Ended December 31, 2007 (Successor) Compared to the Year Ended December 31, 2006 (Successor)

Total revenue for the year ended December 31, 2007 was $363.5 million which is an increase of $91.7 million, or 34%, from the year ended December 31, 2006. Approximately 89% of revenue was attributable to natural gas sales on total volumes of 45.8 Bcfe.

Natural Gas. For the year ended December 31, 2007, natural gas revenue increased by $86.8 million, including the realized impact of derivative instruments, from the comparable period in 2006, to $323.3 million. The increase is primarily attributable to California and Lobo production of 15.9 Bcfe and 14.2 Bcfe, respectively, or 78% of the increased production. This increase is primarily due to an increase in the number of wells producing in 2007 as compared to 2006, which includes the acquisition of the OPEX properties in the second quarter of 2007. The effect of gas hedging activities on natural gas revenue for the year ended December 31, 2007 was a gain of $22.9 million as compared to a gain of $29.6 million for the year ended December 31, 2006. The average realized natural gas price including the effects of hedging decreased from $7.61 per Mcf for the year ended December 31, 2007 as compared to the same period in 2006 of $7.81 per Mcf.

Crude Oil. For the year ended December 31, 2007, oil revenue increased by $4.9 million primarily due to the increase in the average oil price of $7.53 per Bbl from $64.01 per Bbl for the year ended December 31, 2006 as compared to $71.54 for the year ended December 31, 2007. The slight increase in oil production volumes were associated with increased production in California, Lobo and Texas State Water regions due to the new wells in 2007.

Year Ended December 31, 2006 (Successor)

Total revenue of $271.8 million for the year ended December 31, 2006 consists primarily of natural gas sales comprising 87% of total revenue on total volumes of 33.4 Bcfe.

Natural Gas. Natural gas sales revenue was $236.5 million, including the effects of hedging, based on total gas production volumes of 30.3 Bcf. Approximately 75% of the production volumes were from the following three areas: California, Lobo, and Perdido. Average natural gas prices were $7.81 for the respective period including the effects of hedging. The effect of hedging on natural gas sales revenue was an increase of $29.6 million for an increase in total price from $6.83 to $7.81 per Mcf.

Crude Oil. Oil sales revenue was $35.3 million for the year ended December 31, 2006 with oil production volumes of 551.3 MBbls. The oil production volumes were primarily in the Offshore and Other Onshore regions with approximately 75% of the total production volumes. The average oil price was $64.01 per Bbl for the year ended December 31, 2006.

Six Months Ended December 31, 2005 (Successor)

Total revenue of $113.1 million for the six months ended December 31, 2005 consists primarily of natural gas sales comprising 90% of total revenue on total volumes of 13.5 Bcfe.

Natural Gas. 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 an average price of $9.08 per Mcfe, excluding the effects of hedging. California production was affected by the delay in our drilling program 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.

Crude Oil. Oil revenue was $11.0 million based on oil production volumes of 185.6 MBbls. The 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 in the Gulf of Mexico were affected by Hurricanes Katrina and Rita. In addition, production volumes were also affected by a workover program at High Island and East Cameron which was delayed in prior years due to capital constraints imposed by Calpine. Fluctuations in product prices significantly impacted our revenue from existing properties.

Six Months Ended June 30, 2005 (Predecessor)

Total revenue of $103.8 million for the six months ended June 30, 2005 consists primarily of natural gas sales comprising 92% of total revenue on total volumes of 15.5 Bcfe.

Natural Gas. Natural gas sales revenue was $95.6 million with natural gas production volumes of 14.5 Bcf for the six months ended June 30, 2005. The production volumes were primarily from the Sacramento Basin with 6.5 Bcf or 44.8% and Lobo and Perdido with a combined production of 5.5 Bcf or 37.9%. Production volumes were lower than expected due to capital expenditure constraints resulting in reduced drilling activity. The average price for natural gas was $6.59 per Mcf. There was no hedging activity for the six months ended June 30, 2005.

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Crude Oil. For the six months ended June 30, 2005, crude oil sales revenue was $8.2 million based on production volumes of 163.8 MBbls. Production volumes were primarily from the Gulf of Mexico region which produced 72.7 MBbls or 44% of the total oil production. The average price of oil was $49.86 per Bbl for the six months ended June 30, 2005

Operating Expenses

The following table presents information about our operating expenses:

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
	(In thousands, except per unit amounts)			
Lease operating expense	$ 47,044	$ 36,273	$ 15,674	$ 16,629
Depreciation, depletion and amortization	152,882	105,886	40,500	30,679
Production taxes	6,417	6,433	3,975	2,755
General and administrative costs	$ 43,867	$ 33,233	$ 14,687	$ 9,677
$ per unit:				
Avg. lease operating expense per Mcfe	$ 1.03	$ 1.09	$ 1.16	$ 1.08
Avg. DD&A per Mcfe	3.34	3.17	3.00	1.98
Avg. production taxes per Mcfe	0.14	0.19	0.29	0.18
Avg. G&A per Mcfe	$ 0.96	$ 1.00	$ 1.09	$ 0.63

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006 (Successor)

Lease Operating Expense. Lease operating expense increased $10.8 million for the year ended December 31, 2007 as compared to the same period for 2006. This overall increase is primarily due the increase in production of 37% for 2007 which led to higher costs for equipment rentals, maintenance and repairs, and costs associated with non-operated properties. In addition, there was an increase of $5.2 million in ad valorem taxes primarily related to property appraisals in California. The overall increase was offset by a $1.6 million decrease in workover expense primarily due to the insurance reimbursement in 2007 of $2.4 million for claims submitted as a result of Hurricane Rita. Lease operating expense includes workover costs of $0.11 per Mcfe, ad valorem taxes of $0.26 per Mcfe and insurance of $0.05 per Mcfe for the year ended December 31, 2007 as compared to workover costs of $0.19 per Mcfe, ad valorem taxes of $0.20 and insurance of $0.04 per Mcfe for the same period in 2006.

Depreciation, Depletion, and Amortization. Depreciation, depletion and amortization expense increased $47.0 million for the year ended December 31, 2007 as compared to the same period for 2006. The increase is due to a 37% increase in total production and a higher DD&A rate for 2007 as compared to 2006. The DD&A rate for the respective period in 2007 was $3.34 per Mcfe while the rate for the same period in 2006 was $3.17 per Mcfe due to the increase in finding costs.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 1.8% for the year ended December 31, 2007 as compared to 2.4% for the year ended December 31, 2006. This decrease is the result of increased tax credits received for the year ended December 31, 2007 as compared to the same period for 2006. The tax credits were received for natural gas wells drilled in qualifying formations primarily in the Lobo and Perdido regions.

General and Administrative Costs. General and administrative costs, net of capitalized general and administrative costs of $5.5 million for the year ended December 31, 2007, increased by $10.6 million for the year ended December 31, 2007 as compared to the same period for 2006, with capitalized general and administrative costs of $3.5 million. This increase is net of decreases in audit and consulting fees related to higher costs in the first six months of 2006 associated with becoming a public company, which was not incurred in 2007. The increase in costs incurred in the current period are primarily related to increases in the CEO transition costs of approximately $5.0 million, increases in legal fees related to the Calpine litigation of $2.6 million and increases in payroll expenses associated with the payout of bonuses of $2.9 million. The increase is also associated with stock-based compensation, which increased $1.1 million from $5.7 million for the year ended December 31, 2006 to $6.8 million for the year ended December 31, 2007.

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Year Ended December 31, 2006 (Successor)

Lease Operating Expense. Lease operating expense of $36.3 million related directly to oil and gas volumes which totaled 33.4 Bcfe for the year ended December 31, 2006 or costs of $1.09 per Mcfe. Lease operating costs were affected by the wells that came on-line in South Texas. Lease operating expense includes workover costs of $0.19 per Mcfe, ad valorem taxes of $0.20 per Mcfe and insurance of $0.04 per Mcfe.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization was $105.9 million for the year ended December 31, 2006 under the full cost method of accounting. The DD&A rate was $3.17 per Mcfe. There were no ceiling test write-downs for the year ended December 31, 2006.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 2.4% for the year ended December 31, 2006. Production taxes were primarily based on the wellhead values of production and vary across the different regions.

General and Administrative costs. For the year ended December 31, 2006, general and administrative costs were $33.2 million, net of capitalization of certain general and administrative costs of $3.4 million under the full cost method of accounting for oil and natural gas properties. General and administrative costs include salary and employee benefits as well as legal, consulting and auditing fees. In addition, stock compensation expense for the year ended December 31, 2006 was $5.7 million and is included in general and administrative costs.

Six Months Ended December 31, 2005 (Successor)

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 $1.16 per Mcfe. The costs include 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. Lease operating 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 DD&A rate for this period was an average of $3.00 per Mcfe. There were no ceiling test write-downs for the six months ended December 31, 2005.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 3.6% for the six months ended December 31, 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 $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.

Six Months Ended June 30, 2005 (Predecessor)

Lease Operating Expense. Lease Operating Expense was $16.6 million and related to total oil and gas volumes of 15.5 Bcfe or $1.08 per Mcfe for the six months ended June 30, 2005. Lease operating costs include work over cost of $0.22 per Mcfe, ad valorem taxes of $0.22 per Mcfe and insurance of $0.06 per Mcfe. These costs are due to higher taxes in South Texas and a special reclamation tax in California.

Depreciation, Depletion and Amortization. For the six months ended June 30, 2005, depreciation, depletion, and amortization expense was $30.7 million. The predecessor used the successful efforts method of accounting for oil and natural gas properties. The DD&A rate was $1.98 per Mcfe for the six months ended June 30, 2005.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 2.7% for the six months ended December 31, 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 for the six months ended June 30, 2005 were $9.7 million, which is net of capitalized general and administrative costs of $3.6 million. General and administrative costs are comprised of items such as salaries and employee benefits, legal fees, and contract fees. For the six months ended June 30, 2005, of the $9.7 million in total general and administrative costs, $5.9 million relates to salary and employee benefits. In addition, $1.3 million are legal costs and $1.7 million are merger and acquisition costs, which relate to the sale of the oil and natural gas business to the Company.

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Total Other Expense

Other expense includes interest expense, interest income and other income/expense, net which increased $2.5 million for the year ended December 31, 2007 (Successor) as compared to the respective period in 2006. The increase in other expense is the result of reduced interest income in 2007 to offset interest expense as compared to 2006. The interest income is earned on the cash balances, which were greater during 2006 than in 2007. Approximately $35.3 million was expended during the fourth quarter of 2006 to fund various asset acquisitions and approximately $38.7 million was expended during the second quarter of 2007 for the acquisition of the OPEX Properties.

Other expense for the year ended December 31, 2006 (Successor) was $12.9 million and is primarily comprised of interest expense of $17.4 million (net of $2.1 million of capitalized interest) offset by interest income of $4.5 million. The interest expense is associated with the senior secured revolving line of credit and second lien term loan and the interest income is related to the interest earned on the overnight investments of our cash balances.

Other expense for the six months ended December 31, 2005 (Successor) is primarily associated with interest expense of $8.2 million, including amortization of deferred loan fees of $0.6 million related to interest on our Revolver and Term Loan. Interest income of $1.8 million was earned on available cash invested in short term money market investments.

For the six months ended June 30, 2005 (Predecessor), other expense of $7.0 million was associated with the intercompany debt with Calpine Corporation.

Provision for Income Taxes

For the year ended December 31, 2007(Successor), the effective tax rate was 37.3% as compared to the effective tax rate of 38.3% for the year ended December 31, 2006 (Successor). For the six months ended December 31, 2005 (Successor), the effective tax rate was 39.7% and for the six months ended June 30, 2005 (Predecessor), the effective tax rate was 38.1%. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate primarily due to the effect of state taxes.

Liquidity and Capital Resources

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

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of our production, thereby mitigating our exposure to price declines, but these transactions 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 in which our derivative transactions are in place. The effects of these derivative transactions on our natural gas sales are discussed above under “Results of Operations – Natural Gas”. In addition, the majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels.

Senior Secured Revolving Line of Credit. In July 2005, BNP Paribas provided us with a senior secured revolving line of credit concurrent with the Acquisition in the amount of up to $400.0 million (“Revolver”). This Revolver was syndicated to a group of lenders on September 27, 2005. Availability under the Revolver is restricted to the borrowing base, which initially was $275.0 million and was reset to $325.0 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 in our private equity offering in July 2005. In July 2005, we repaid $60.0 million of the $225.0 million in original borrowings on the Revolver. In addition, in 2007, we increased our net borrowings against the Revolver by $5.0 million, bringing the balance to $170.0 million at December 31, 2007. 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. In May 2007, the borrowing base was adjusted to $350.0 million. Initial amounts outstanding under the Revolver bore interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00% (5.82% at December 31, 2007). These rates over LIBOR were adjusted in May 2007 to be 1.00% to 1.75%. Such margins will fluctuate based on the 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 pretax SEC 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 contract. 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, 2007, our current ratio was 1.8 to 1.0, as adjusted per current agreements, and our leverage ratio was 0.9 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 obtained a waiver of any breach of a loan covenant arising out of Calpine's institution of Calpine's fraudulent conveyance action against us and were in compliance with all covenants at December 31, 2007. All amounts drawn under the Revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $179.0 million at December 31, 2007.

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Second Lien Term Loan. In July 2005, BNP Paribas provided us with a second lien term loan in the amount of $100.0 million ("Term Loan"). On September 27, 2005, we repaid $25.0 million of borrowings on the Term Loan, reducing the balance to $75.0 million and syndicated the Term 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 Term Loan has been reduced to LIBOR plus 4.00% (8.82% at December 31, 2007). The Term 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. 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 obtained a waiver of any breach of a loan covenant arising out of Calpine's institution of Calpine's fraudulent conveyance action against us and were in compliance with all covenants at December 31, 2007. The revised principal balance of the Term Loan is due and payable on July 7, 2010.

Our ability to raise capital depends on the current state of the financial markets, which are subject to general and economic and industry conditions. Therefore, the availability of and price of capital in the financial markets could negatively affect our liquidity position. Our current liquidity is supported by our revolving credit facility maturing on July 7, 2009.

Working Capital

At December 31, 2007, we had a working capital deficit of $62.9 million as compared to a working capital surplus of $30.7 million at December 31, 2006. Our working capital is affected primarily by fluctuations in the fair value of our commodity derivative instruments, deferred taxes associated with hedging activities, cash and cash equivalents balance and our capital spending program. This deficit was largely caused by the decrease in our cash balance to fund capital expenditures, including property acquisitions as well as an increase in our accrued capital costs. As of December 31, 2007, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $3.2 million and $4.0 million, respectively, and there was no balance for current deferred tax assets. In addition, the associated working capital liability balances for accrued liabilities were approximately $64.2 million as of December 31, 2007.

We believe we have adequate expected cash flows from operations and available borrowings under our Revolver to fund our budgeted capital expenditures.

Cash Flows

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
			(In thousands)	
Cash flows provided by operating activities	$ 257,307	$ 199,610	$ 63,744	$ 59,379
Cash flows used in investing activities	(322,041)	(236,064)	(943,246)	(30,645)
Cash flows provided by (used in) financing activities	5,170	(490)	979,226	(27,239)

Net (decrease) increase in cash and cash equivalents	$	(59,564)	$	(36,944)	$	99,724	$	1,495

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation and general and administrative expenses. Net cash provided by operating activities ("Operating Cash Flow") continued to be a primary source of liquidity and capital used to finance our capital expenditures for the year ended December 31, 2007.

Cash flows provided by operating activities increased by $57.7 million for the year ended December 31, 2007 as compared to the same period for 2006. This increase is largely affected by our net income, excluding non-cash expenses such as depreciation, depletion and amortization and deferred income taxes. For the year ended December 31, 2007, we had net income of $57.2 million with an increase of production of 37% as compared to the year ended December 31, 2006 with net income of $44.6 million. As noted above, we also had a working capital deficit of $62.9 million, which was largely caused by the decrease in our cash balance to fund capital expenditures, including property acquisitions. For the year ended December 31, 2007, we incurred approximately $336.1 million in capital expenditures as compared to $242.2 million for the year ended December 31, 2006.

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Net cash provided by operating activities for the year ended December 31, 2006 was $199.6 million with net income of $44.6 million and total production of 33.4 Bcfe. Natural gas prices averaged $7.81 per Mcf, including the effects of hedging, and oil averaged $64.01 per Bbl.

Net cash provided by operating activities 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.

Net cash provided from operations for the six months ended June 30, 2005 was $59.4 million generated from total production of 15.5 Bcfe with revenue of $103.8 million and net income of $30.2 million before tax. Natural gas prices averaged $6.59 per Mcf and oil averaged $49.86 per Bbl during the quarter.

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

Cash flows used in investing activities increased by $86.0 million for the year ended December 31, 2007 as compared to the same period for 2006 and related to our expenditures for the acquisition of the OPEX properties and drilling and development of oil and gas properties. During the year ended December 31, 2007, we participated in the drilling of 195 gross wells as compared to the drilling of 142 gross wells for the year ended December 31, 2006.

Cash used in investing activities for the year ended December 31, 2006 was $236.1 million. These expenditures were primarily from the California, South Texas and Gulf of Mexico regions and included acquisitions of $35.3 million.

Cash used in investing activities for the six months ended December 31, 2005 was $943.2 million primarily relating to the Acquisition 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.

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

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

Cash flows provided by financing activities increased by $5.7 million for the year ended December 31, 2007 as compared to the same period for 2006. The net increase is primarily related to net borrowings of $5.0 million made in 2007 against the Revolver. In addition, there were fewer purchases of treasury stock for the year ended December 31, 2007 than for the comparable period in 2006. The purchases of stock were surrendered by certain employees to pay tax withholding upon vesting of restricted stock awards. These purchases are not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to purchase shares of common stock.

Net cash used in financing activities for the year ended December 31, 2006 was primarily associated with the purchases of treasury stock surrendered by the employees to pay tax withholding upon the vesting of restricted stock awards offset by proceeds from issuances of common stock.

Net cash provided by 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 borrowings 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.

Commodity Price Risks and Related Hedging Activities

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

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We also entered into a series of basis swaps transactions covering a portion of our 2008 production. The basis swap requires us to pay Natural Gas Intelligence ("NGI") PG&E Citygate Index for notional volumes for calendar year 2008. The counterparty will pay the float price based on the last trade day settlement of the corresponding forward month contract settlement of the NYMEX Henry Hub index. When combined with existing NYMEX Henry Hub fixed price swaps, this effectively creates a fixed price swap that settles at PG&E Citygate Index. Consistent with our hedge policy the basis swap transactions will be combined with the NYMEX fixed price swaps noted above and treated as PG&E fixed price swaps in subsequent disclosures. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk".

The following table sets forth the results of commodity hedging transaction settlements for the year ended December 31, 2007:

		For the Year Ended December 31, 2007		For the Year Ended December 31, 2006
Natural Gas				
Quantity settled (MMBtu)		23,464,500		20,075,000
Increase in natural gas sales revenue (In thousands)	$	22,926	$	29,578

Interest Rate Risks and Related Hedging Activities

Borrowings under our Revolver and Term Loan mature on July 7, 2009 and July 7, 2010, respectively, and bear interest at a LIBOR-based rate. This exposes us to risk of earnings loss due to changes in market interest rates. To mitigate this exposure, we have entered into a series of interest rate swap agreements through June 2009 to mitigate such risk. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into additional interest rate swap agreements in the future.

The following table sets forth the results of third party interest rate hedging transactions settled for the year ended December 31, 2007:

		For the Year Ended December 31, 2007		For the Year Ended December 31, 2006
Interest Rate Swaps				
Decrease in interest expense (In thousands)	$	20	$	-

In accordance with SFAS No. 133, as amended, all derivative instruments, not designated as a normal purchase sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instrum