Rosetta Resources Inc.
Form 424B3
November 30, 2006

Filed pursuant to Rule 424(b)(3)
Registration Number 333-128888

PROSPECTUS SUPPLEMENT NO. 3
(To the Prospectus dated June 14, 2006)

50,000,000 Shares of
Common Stock

This Prospectus Supplement No. 3 supplements the prospectus dated June 14, 2006 and the Prospectus Supplements No. 1 and No. 2 dated August 15, 2006 and November 14, 2006, respectively, (together, the "Prospectus"), relating to the sale by the holders of Common Stock of Rosetta Resources Inc. This prospectus supplement should be read in conjunction with the Prospectus which is to be delivered with this prospectus supplement. If there is any inconsistency between the information in the Prospectus and this prospectus supplement, you should rely on the information in this prospectus supplement.

INVESTING IN OUR COMMON STOCK INVOLVES RISK. SEE "RISK FACTORS" BEGINNING ON PAGE 17 OF OUR ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2005 AND ON PAGE 10 OF THE PROSPECTUS.

This prospectus supplement is filed for the purposes of including the information contained in our amendment to our quarterly report on Form 10-Q/A for the quarter ended September 30, 2006, which was filed with the Securities and Exchange Commission on November 30, 2006.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED UPON THE ADEQUACY OR ACCURACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The date of this Prospectus Supplement is November 30, 2006.

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

Amendment No. 1 to Form 10-Q on
FORM 10-Q/A

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

For The Quarterly Period Ended September 30, 2006

OR

o Transition Report Pursuant To Section 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**

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

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

Large accelerated filer o Accelerated filer o Non-Accelerated filer x

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

The number of shares of the registrant's Common Stock, $.001 par value per share, outstanding as of November 2, 2006 was 50,647,319.

Explanatory Note

Rosetta Resources, Inc. (the “Company”) is filing this Amendment No. 1 to its Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006 (the “Original Filing”), which was originally filed with the Securities and Exchange Commission (“SEC”) on November 14, 2006. The purpose of this filing is to clarify a typographical error of a certain number figure in the Company’s Original Filing. In Part I - Item 2 Management’s Discussion and Analysis of Financial Condition and Results of Operations, in the Critical Accounting Policies and Estimates, the ceiling test writedown which would have been charged to earnings had hedge adjusted market prices at September 30, 2006 been used was incorrectly reported as $182.1 million. The correct amount should have been $142.1 million consistent with the amount reported in Note 5 of the notes to the Consolidated/Combined Financial Statements included in the Original Filing.

Additionally, in connection with the filing of Amendment No. 1 and pursuant to SEC rules, the Company is including as Exhibits to this Amendment No. 1 certain certifications as of the date of this Amendment No. 1. Except as described herein, this Amendment No. 1 does not amend any other disclosure in the Original Filing as originally filed and does not reflect events occurring after the Original Filing. The Company hereby replaces all of Part I - Item 2 Management’s Discussion and Analysis of Financial Condition and Results of Operations in the Original Filing with Item 2 set forth in this Amendment No. 1.

Part I. Financial Information

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

Rosetta Resources Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties in the United States. We were formed as a Delaware corporation in June 2005. In July 2005, we acquired the domestic oil and natural gas business of Calpine Corporation and its affiliates. Our main operations are concentrated in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the Gulf of Mexico and the Rocky Mountains.

In this section, we sometimes refer to Rosetta as "Successor", and we sometimes refer to Calpine Corporation and its affiliates, from whom we acquired our initial domestic oil and natural gas business and associated oil and natural gas properties as "Predecessor". Additionally, we sometimes refer to our acquisition of Calpine's domestic oil and natural gas business as the "Acquisition".

In the first nine months of 2006, relatively high oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of those goods and services. Given the inherent volatility of oil and natural gas prices that are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions. We focus our efforts on increasing natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in fair market value of hedges we executed to mitigate the volatility in the changes of oil and natural gas prices in future periods when such positions are settled as these instruments meet the criteria to be accounted for as cash flow hedges. Until settlement, the changes in fair market value of our hedges will be included as a component of stockholder's equity to the extent effective. In periods of rising prices, these transactions will mitigate future earnings and in periods of declining prices will increase future earnings in the respective period the positions are settled.

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

Financial Highlights

For the nine month period ended September 30, 2006, we produced 24.4 Bcfe with average revenue of $8.16 per Mcfe. Our natural gas production for the nine months ended September 30, 2006 was 21.9 Bcf and our oil production for the same period was 414.3 MBbls. Our average natural gas prices were $7.84 per Mcf, including the effects of hedging, and average oil prices for the same period were $65.99 per Bbl. For the nine months ended September 30, 2006, we had revenues of $199.1 million including the effects of hedging with net income of $31.4 million and diluted earnings per share of $0.62.

Calpine Bankruptcy

On December 20, 2005, Calpine and certain of its subsidiaries, including Calpine Fuels, filed for protection under federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (“the Court”). The filing raises certain concerns regarding aspects of our relationship with Calpine which we will closely monitor as the Calpine bankruptcy proceeds. The following are our principal areas of concern:

- Calpine, its creditors or interest holders may challenge the fairness of some or all of the Acquisition. For a number of reasons, including our understanding of the process which Calpine followed in allowing market forces to set the purchase price for the Acquisition, we believe that it is unlikely that any challenge to the fairness of the Acquisition would be successful;

- The bankruptcy proceeding may prevent, frustrate or delay our ability to receive record legal title to certain properties originally listed as determined to be Non-Consent Properties which we are entitled to obtain under the Purchase Agreement;

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

- Calpine may stop purchasing gas from us under our gas purchase contracts with Calpine. Since the date of the bankruptcy filing, Calpine has continued buying natural gas from us and making timely payments. Calpine has sought and obtained bankruptcy court approval to continue payments to us for our delivery of natural gas under our gas purchase and sale contracts with Calpine. Under the terms of these contracts, in the event of Calpine's default in making timely payments, we are entitled to suspend deliveries to Calpine and instead sell this gas to third parties at comparable prices and terms until Calpine cures any such default (Calpine having 60 days after notice to do so). In terms of the likely impact of Calpine's default under these contracts, should this ever occur, we expect to be able to minimize our exposure for Calpine's non-payment to four days of sales under these contracts, or approximately $1.5 million in lost sales at production rates and prices as of September 30, 2006.

Transfers Pending at Calpine's Bankruptcy

At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to Non-Consent Properties identified by Calpine as requiring third party consents or waivers of preferential rights to purchase that were not received before closing. Those Non-Consent Properties were not included in conveyances delivered at the closing. Subsequent analysis determined that a portion of the Non-Consent Properties, with an approximate allocation value of $29 million under the Purchase Agreement did not require consents or waivers. For that portion of the Non-Consent Properties for which third party consents were in fact required (having an approximate value of $39 million under the Purchase Agreement) and for which we obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, we believe that 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 a third party's preferential right to purchase, and, in addition, a post-closing adjustment is required to credit Rosetta for approximately $0.3 million for a property which was transferred to us but 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 a third party's preferential right to purchase) were satisfied earlier, and certainly no later than December 15, 2005, when we tendered once again 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 to us 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 and further assurances required to eliminate any open issues on title to the remaining properties discussed below, we are prepared to pay Calpine approximately $68 million, subject to appropriate adjustment for the associated net revenues and expenses through December 15, 2005. Our statement of operations for the nine months ended September 30, 2006 does not include any net revenues or production from any of the Non-Consent Properties.

If Calpine does not provide us with record title, free of any mortgages for all of these properties and other liens, to any of the Non-Consent Properties (excluding that portion of these properties subject to a third party's preferential right to purchase), we will have a total of approximately $68 million available to us for general corporate purposes, including for the purpose of acquiring additional properties. We also have approximately $7.1 million, previously withheld for that portion of the Non-Consent Properties subject to a third party's preferential right to purchase, which will also be available to us for general corporate purposes, including for the purpose of acquiring additional properties.

In addition, as to certain of the other oil and natural gas properties we purchased from Calpine in the Acquisition and for which payment was made on July 7, 2005, we will seek additional documentation from Calpine to eliminate any open issues in our title or resolve any issues as to the clarity of our ownership. Requests for additional documentation are customary in connection with transactions similar to the Acquisition. In the Acquisition, certain of these properties require ministerial governmental action approving us as qualified assignee and operator, which is typically required even though in most cases Calpine has already conveyed the properties to us free and clear of mortgages and liens in favor of Calpine's creditors. As to certain other properties, the documentation delivered by Calpine at closing under the Purchase Agreement was incomplete. We remain hopeful that Calpine will continue to work cooperatively with us to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all properties acquired by us in the Acquisition, Calpine contractually agreed to provide us with such further assurances as we may reasonably request. Nevertheless, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these issues, we will pursue all available remedies, including but not limited to a declaratory judgment to enforce our rights and actions to quiet title. After pursuing these matters, if we experience a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to us, an outcome we consider to be remote, then we could experience losses which could have a material adverse effect on our financial condition, statement of operations and cash flows.

On June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding in the Court seeking the entry of an order authorizing Calpine to assume certain oil and natural gas leases Calpine has 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 the motion in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a statutory deadline. Calpine's motion did not request that the Court determine whether these properties belong to us or Calpine, but we understand it 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 our rights and interest in and to the leases. 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. The objection also requested that (a) the 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 Minerals Management Service has subsequently recognized us as owner and operator of these properties and (b) any order entered by the 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 Court to require the parties to promptly address and resolve any remaining issues under the pre-bankruptcy Purchase Agreement with Calpine and proposed to the Court that the parties seek arbitration (or at least mediation) to complete the following:

- Calpine's conveyance of 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, which we have concluded is approximately $79 million, consisting of roughly $68 million for the Non-Consent Properties and approximately $11 million in other true-up payment obligations.

At a hearing held on July 12, 2006, the Court in Calpine Corporation's bankruptcy took the following steps:

- In response to an objection filed by the Department of Justice and asserted by the California State Lands Commission 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 Minerals Management Service of the United States Department of Interior) (the "MMS Oil and Gas Leases") and the State of California (and managed by the California State Lands Commission) (the “CSLC Leases”). Calpine and both 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 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.

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 and unliquidated damages in amounts that can not presently be determined.

By a proposed stipulation dated October 18, 2006, Calpine and the Department of Justice agreed to further extend the deadline to assume or reject the MMS Oil and Gas Leases under Section 365 of the Bankruptcy Code from November 15, 2006 to January 31, 2007, to the extent the MMS Oil and Gas Leases are "unexpired leases" subject to Section 365. We have filed an objection to this proposed stipulation requesting the Court condition its approval of the proposed stipulation on inclusion of appropriate language adequately reserving our rights with respect to the MMS Oil and Gas Leases and clarifying that the United States Department of Interior will not take regulatory action with respect to such leases without first seeking relief from the Court. On November 1, 2006, Calpine and the State of California submitted a similar proposed stipulation extending the deadline to assume or reject the CSLC Leases until January 31, 2007. We will take all necessary action to ensure our rights under the CSLC Leases are fully protected.

We continue to undertake to work with Calpine on a cooperative and expedited basis toward resolution of unresolved conveyance of properties and post closing adjustments under the Purchase Agreement.

Critical Accounting Policies and Estimates

In our Annual Report on Form 10-K for the year ended December 31, 2005, we identified our most critical accounting policies upon which our financial condition depends as those relating to oil and natural gas reserves, full cost method of accounting, derivative transactions and hedging activities, asset retirement obligations, income taxes and stock-based compensation.

We assess the impairment for oil and natural gas properties for the full cost pool quarterly using a ceiling test to determine if impairment is necessary. If the net capitalized costs of oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, it would reduce earnings and impact shareholders' equity in the period of occurrence and result in a lower depreciation, depletion and amortization expense in the future.

Our ceiling test computation was calculated using hedge adjusted market prices at September 30, 2006 which were based on a Henry Hub gas price of $4.18 per MMBtu and a West Texas Intermediate oil price of $62.91 per barrel. The use of these prices resulted in a writedown of $142.1 million at September 30, 2006. Cash flow hedges of natural gas production in place at September 30, 2006 increased the calculated ceiling value by approximately $92.2 million (net of tax). However, subsequent to September 30, 2006 the market price for Henry Hub increased to $7.42 per MMBtu and the price for West Texas Intermediate decreased to $58.07 per barrel, and utilizing these prices, our net capitalized costs of oil and gas properties exceeded the ceiling amount. As a result no writedown was recorded for the quarter ended September 30, 2006. The ceiling value calculated using subsequent prices includes approximately $17.9 million related to the positive effects of future cash flow hedges of natural gas production. Due to the volatility of commodity prices, should natural gas and oil prices decline in the future, it is possible that a writedown could occur.

On January 1, 2006, we adopted the accounting policies described in Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004) "Share-Based Payments" ("SFAS No. 123R"). This statement applies to all awards granted, modified, repurchased or cancelled after January 1, 2006 and to the unvested portion of all awards granted prior to that date. We adopted this statement using the modified version of the prospective application (modified prospective application). Under this method, no prior year amounts have been restated. Prior to January 1, 2006, we accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by the Accounting Principles Board Opinion ("APB") No. 25, "Accounting for Stock Issued to Employees".

With the adoption of SFAS No.123R, one of the differences in our method of accounting is that unvested stock options are now expensed as a component of stock-based compensation recorded in General and Administrative Costs in the Consolidated/Combined Statement of Operations. This expense is based on the fair value of the award at the original grant date and is recognized over the remaining vesting period. Prior to the adoption of SFAS No. 123R, this amount was included as a pro forma disclosure in the Notes to the Consolidated Financial Statements. Compensation expense for the three and nine months ended September 30, 2006 (Successor) was $1.0 million and $4.3 million, respectively.

In addition, the application of the forfeiture rate in calculating the fair value has changed with the adoption of SFAS No.123R. We are now required to estimate forfeitures on all equity-based compensation and adjust period expenses instead of recording the actual forfeitures as they occur. Furthermore, we are required to immediately expense certain awards to retirement eligible employees depending on the structure of each individual plan. The retirement eligibility provision only applies to new grants that were awarded after January 1, 2006.

Results of Operations

For the three months ended September 30, 2006, the results of operations have been compared to the amounts reported for the three months ended September 30, 2005. However, as we acquired the domestic oil and natural gas business of Calpine Corporation

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and affiliates in July 2005, the year-to-date results for the period ended September 30, 2006 and 2005 are not comparable and are noted as Successor for the three months ended September 30, 2005 and Predecessor for the six months ended June 30, 2005. These two year-to-date periods have not been compared because of differences in accounting principles, 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, "Accounting for Stock-Based Compensation" to measure the cost of employee services received in exchange for an award of equity instruments, whereas we adopted the intrinsic value method of accounting for stock options and stock awards effective July 1, 2005, and as required, have adopted the guidance for stock-based compensation under SFAS No. 123R effective January 1, 2006. We believe comparative results for the nine months ended September 30, 2006 and 2005 would be misleading and, therefore, have chosen to present the periods separately.

Successor

Revenues. Our revenues are derived from the sale of our oil and natural gas production, which includes the effects of qualifying hedge contracts. Total revenue of $71.2 million for the third quarter consists primarily of natural gas sales comprising 86% of total revenue on total volumes of 8.7 Bcfe. For the nine months ended September 30, 2006, natural gas sales also comprised 86% of total revenue on total volumes of 24.4 Bcfe.

	Successor-Consolidated		Successor-Consolidated	Predecessor-Combined
	Three Months Ended September 30,		Nine Months Ended September 30,	Six Months Ended June 30,
	2006	2005	2006	2005
	(In thousands, except per unit amounts)			
Total revenues	$ 71,197	$ 57,865	$ 199,122	$ 103,831
Production:				
Gas (Bcf)	7.9	6.4	21.9	14.5
Oil (MBbls)	143.5	103.0	414.3	163.8
Total Equivalents (Bcfe)	8.7	7.1	24.4	15.5
$ per unit:				
Avg. Gas Price per Mcf	$ 7.77	$ 8.03	$ 7.84	$ 6.59
Avg. Gas Price per Mcf excluding Hedging	6.61	8.38	6.94	-
Avg. Oil Price per Bbl	68.51	60.03	65.99	49.86
Avg. Revenue per Mcfe	$ 8.18	$ 8.20	$ 8.16	$ 6.70

Natural Gas. Natural gas sales revenue increased by $9.7 million, including the realized impact of derivative instruments, for the three months ended September 30, 2006 as compared to the three months ended September 30, 2005. The increase is due to a gain on derivative instruments of $11.4 million offset by a decrease in natural gas sales of $1.7 million. The decrease in natural gas sales revenue is due to a 21% decrease in natural gas prices offset by an increase in gas production volumes. The largest increase in production volumes were in the Lobo, Other Onshore, and Perdido regions due to successful well completions. The average natural gas price decreased from $8.03 per Mcfe to $7.77 per Mcfe, including the effects of hedging, for the three months ended September 30, 2006 as compared to the three months ended September 30, 2005.

Natural gas sales revenue was $171.8 million for the nine months ended September 30, 2006, including the effects of hedging, based on total gas production volumes of 21.9 Bcf. Approximately 80% of the production volumes were from the following three areas: California, Lobo and Perdido. Average natural gas prices were $7.84 per Mcf for the respective period. The effect of hedging on natural gas sales revenue was an increase of $19.8 million for an increase in total price from $6.94 to $7.84 per Mcf.

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.

Crude Oil. Oil sales revenue increased by $3.6 million for the three months ended September 30, 2006 as compared to the three months ended September 30, 2005. The increase is due to a 39% increase in oil production volumes with a 14% increase in oil prices. Total oil production volumes increased from 103.0 MBbls for the three months ended 2005 to 143.5 MBbls for the three months ended September 30, 2006, primarily due to increases in the Offshore and Other Onshore regions. The average oil price increased to $68.51 for the three months ended September 30, 2006 from $60.03 for the comparable period in the prior year.

Oil sales revenue was $27.3 million for the nine months ended September 30, 2006 with oil production volumes of 414.3 MBbls. The oil production volumes were primarily in the Offshore and Other Onshore regions with approximately 77% of the total production volumes. The average oil price was $65.99 per Bbl for the nine months ended September 30, 2006.

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 for the three and nine months ended September 30, 2006.

	Successor-Consolidated		Successor-Consolidated	Predecessor-Combined
	Three Months Ended September 30,		Nine Months Ended September 30,	Six Months Ended June 30,
	2006	2005	2006	2005
	(In thousands, except per unit amounts)			
Lease operating expense	$ 9,449	$ 8,849	$ 27,330	$ 16,629
Depreciation, depletion and amortization	27,906	21,720	77,574	30,679
General and administrative costs	$ 8,316	$ 6,880	$ 24,645	$ 9,677
$ per unit:				
Avg. lease operating expense per Mcfe	$ 1.09	$ 1.25	$ 1.12	$ 1.08
Avg. DD&A per Mcfe	3.21	3.08	3.18	1.98
Avg. G&A per Mcfe	$ 0.96	$ 0.83	$ 1.01	$ 0.63

Our operating expenses for the three and nine months ended September 30, 2006 are primarily related to the following items:

- *Lease Operating Expense*. Lease operating expense increased $0.6 million from the three months ended September 30, 2005 to the three months ended September 30, 2006. The overall increase is due to an increase in lease expense and ad valorem tax of $2.3 million offset by a decrease in work over expense of $1.7 million primarily due to insurance reimbursement for claims submitted as a result of Hurricane Rita. The average lease operating expense decreased to $1.09 per Mcfe for the three months ended September 30, 2006 from $1.25 per Mcfe for the comparable period in the prior year.

Lease operating expense of $27.3 million related directly to oil and natural gas volumes which totaled 24.4 Bcfe for the nine months ended September 30, 2006 or costs of $1.12 per Mcfe. Lease operating costs were affected by wells that came on-line in South Texas.

For the six months ended June 30, 2005, lease operating expense was $16.6 million related to total oil and gas volumes of 15.5 Bcfe or $1.08 per Mcfe. The 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.

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Depreciation, Depletion, and Amortization. Depreciation, depletion, and amortization expense increased by $6.2 million from the three months ended September 30, 2005 as compared to the three months ended September 30, 2006 due to increased production volumes and a higher rate. The depletion rate increased from $2.97 per Mcfe to $3.13 per Mcfe.

Depreciation, depletion, and amortization expense was $77.6 million for the nine months ended September 30, 2006 under the full cost method of accounting for oil and natural gas properties.

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 depletion rate was $1.97 per Mcfe for the six months ended June 30, 2005.

· *General and Administrative Costs*. General and administrative costs for the three months ended September 30, 2006 were $8.3 million compared to $6.9 million for the same period in 2005, which represents a 21% increase over the prior year. The increase was due to an increase in outside legal and consulting fees relating to the Calpine bankruptcy and increased Sarbanes Oxley costs due to the hiring of a consulting firm to assist with the Sarbanes Oxley implementation.

For the nine months ended September 30, 2006, general and administrative costs were $24.6 million, net of capitalization of certain general and administrative costs of $2.6 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 nine months ended September 30, 2006 was $4.3 million and is included in 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.

Total Other expense. Other expense decreased from the third quarter in 2005 to the third quarter in 2006 by $0.1 million due to a litigation accrual that was settled in the third quarter of 2006.

For the nine months ended September 30, 2006, other expense was $9.7 million composed of interest expense of $13.1 million offset by interest income of $3.4 million. The interest expense is associated with the senior secured revolving line of credit and second lien term loan and interest income is related to the interest earned on the overnight investments of our cash balances.

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

Provision for Income Taxes. The effective tax rate for the three and nine months ended September 30, 2006 was 38.0%. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to state taxes, tax credits and other permanent differences. The effective tax rate for six months ended June 30, 2005 was 38.1%.

Liquidity and Capital Resources

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We 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 our derivative transactions are in place. In addition, the majority of our capital expenditures will be discretionary and could be curtailed if our cash flows decline from expected levels. In connection with entering into our credit facilities in July 2005, we entered into a series of natural gas fixed-price swaps for a significant portion of our expected production through 2009. In addition, in the third quarter of 2006, we entered into two additional fixed-price swaps for a total of 9,041 MMBtu per day for 2007 and 2008. Consistent with our hedge policy, in December 2005, we entered into two costless collar transactions, which are intended to establish a floor price and ceiling price for approximately 10,000 MMBtu per day which represents approximately 10% of our 2006 natural gas production based on a third party reserve report at December 31, 2005. In the third quarter of 2006, we also entered into two additional costless collar transactions for a total of 10,000 MMBtu per day for 2007. The effects of these derivative transactions on our financial statements are discussed above under "Results of Operations - Natural Gas". Additionally, we may enter into other agreements including fixed-price, forward price, physical purchase and sales contracts, futures, financial swaps, option contracts and put options.

Senior Secured Revolving Line of Credit. BNP Paribas, in July 2005 provided us with a senior secured revolving line of credit concurrent with the acquisition in the amount of up to $400.0 million. This revolving line of credit was syndicated to a group of lenders on September 27, 2005. Availability under the revolver is restricted to the borrowing base, which initially was $275.0 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 through which we received $70.0 million of funds (net of transaction fees). In July 2005, we repaid $60.0 million of the $225.0 million in original borrowings on the Revolver. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements. Amounts outstanding under the revolver bear interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00%. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the PV-10 reserve value, a guaranty by all of our domestic subsidiaries, a pledge of 100% of the stock of domestic subsidiaries and a lien on cash securing the Calpine gas purchase and sale 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 September 30, 2006, our current ratio was 3.7 and our leverage ratio was 1.3. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at September 30, 2006. All amounts drawn under the revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $159.0 million at September 30, 2006.

In July 2006, we entered into a Deposit Account Control Agreement in order to provide a security interest under the terms of our senior secured revolving line of credit. Under the terms of the Deposit Account Control Agreement, we were required to maintain $15.0 million on account to keep a borrowing base of $325.0 million. Based on the semi-annual review of our borrowing base, a consent agreement was signed in October 2006 in which the borrowing base remained at $325.0 million and we were no longer required to maintain the $15.0 million balance pursuant to the Deposit Account Control Agreement

Second Lien Term Loan. BNP Paribas, in July 2005, also provided us with a second lien term loan concurrent with the acquisition, in the amount of $100.0 million. 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 loan to a group of lenders including BNP Paribas. Borrowings under the term loan initially bore interest at LIBOR plus 5.00%. As a result of the hedges put in place in July 2005 and the favorable effects of our private equity placement, as described above, the interest rate for the second lien term loan has been reduced to LIBOR plus 4.00%. The loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at September 30, 2006. The revised principal balance is due and payable on July 7, 2010.

Cash Flows

	Successor Nine months ended September 30, 2006	Successor Three months ended September 30, 2005	Predecessor Six months ended June 30, 2005
	(In thousands)		
Cash flows provided by operating activities	$ 141,621	$ 63,250	$ 59,379
Cash flows used in investing activities	(162,161)	(937,592)	(30,645)
Cash flows provided by (used in) financing activities	(441)	981,315	(27,239)
Net (decrease) increase in cash and cash equivalents	$ (20,981)	$ 106,973	$ 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 expense and administrative expenses.

Net cash provided by operating activities for the nine months ended September 30, 2006 was $141.6 million generated from total production of 24.4 Bcfe with revenue of $199.1 million and net income before income tax of $50.7 million. Natural gas averaged $7.84 per Mcf, including the effects of hedging and oil averaged $65.99 per Bbl during this period. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures.

Net cash provided from operations for the three months ended September 30, 2005 was $63.3 million generated from total production of 7.1 Bcfe. Natural gas prices averaged $8.03 per Mcf, including the effects of hedging, and oil averaged $60.03 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 used in investing activities for the nine months ended September 30, 2006 was $162.2 million and primarily related to the purchases of property and equipment with additional capital expenditures accrued for at quarter end as well as the restrictions placed on the cash balance of $15 million associated with the Deposit Account Control Agreement

Cash used in investing activities for the three months ended September 30, 2005 was $937.6 million due to the acquisition of the domestic oil and natural gas business of Calpine in the amount of $910 million in total capital expenditures.

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, the acquisition of new debt facilities or increase in intercompany notes payable and corresponding repayments of debt.

Net cash used in financing activities for the nine months ended September 30, 2006 was $0.4 million and primarily related to the equity offering transaction fees, proceeds from issuances of common stock and stock-compensation excess tax benefit.

Net cash provided by financing activities for the three months ended September 30, 2005 was $981.3 million. This was due to $800 million in equity offering proceeds net of $54.0 million in transaction fees and $325 million in our senior credit facility for the acquisition of the domestic oil and natural gas business of Calpine and operating needs offset by 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.

Capital Expenditures

Our capital expenditures for the nine months ended September 30, 2006 were $151.0 million and we currently expect to expend approximately $40 million during the fourth quarter of 2006. These capital expenditures were primarily associated with increased drilling activity in California and South Texas. We believe we have adequate expected cash flows from operations and available borrowings under our revolving credit facility to cover our budgeted capital expenditures.

Part II. Other Information

Item 6. Exhibits

31.1 Certification of Periodic Financial Reports by B.A. Berilgen in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002

31.2 Certification of Periodic Financial Reports by Michael J. Rosinski in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		Rosetta Resources Inc.
Date: November 30, 2006	By:	/s/ Michael J. Rosinski
		Michael J. Rosinski Executive Vice President and Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)

ROSETTA RESOURCES INC.

EXHIBIT INDEX

Exhibit Number	Description
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