Rosetta Resources Inc.
Form 10-Q
August 14, 2006

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

FORM 10-Q

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

For The Quarterly Period Ended June 30, 2006

[ ] 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 [ ]

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 [ ] Accelerated filer [ ] 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 [ ] No [X]

The number of shares of the registrant's Common Stock, $.001 par value per share, outstanding as of August 3, 2006 was 50,696,200.

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Part I. Financial Information
Item 1. Financial Statements

Rosetta Resources Inc.
Consolidated Balance Sheet
(In thousands, except per share amounts)

	June 30, 2006 (Unaudited)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 93,206	$ 99,724
Accounts receivable	24,930	40,051
Derivative instruments	9,792	1,110
Deferred income taxes	-	10,962
Income tax receivable	-	6,000
Other current assets	12,232	9,411
Total current assets	140,160	167,258
Oil and natural gas properties, full cost method, of which $43.6 million at June 30, 2006 and $30.6 million at December 31, 2005 were excluded from amortization	1,074,642	973,185
Other	3,393	2,912
	1,078,035	976,097
Accumulated depreciation, depletion, and amortization	(89,480)	(40,161)
Total property and equipment, net	988,555	935,936
Long-term accounts receivable	792	1,726
Deferred loan fees	3,965	4,555
Deferred income taxes	-	8,594
Other assets	1,090	1,200
	5,847	16,075
Total assets	$ 1,134,562	$ 1,119,269
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 17,513	$ 13,442
Royalties payable	11,444	15,511
Derivative instruments	-	29,957
Interest payable	-	133
Prepayment on gas sales	9,888	14,528
Deferred income taxes	3,721	-
Other current liabilities	24,633	28,264
Total current liabilities	67,199	101,835
Long-term liabilities:		
Derivative instruments	28,907	52,977
Long-term debt	240,000	240,000
Asset retirement obligation	9,499	9,034
Deferred income taxes	12,276	-
Total liabilities	357,881	403,846
Commitments and contingencies (Note 9)		

Stockholders' Equity:				
Common stock, $0.001 par value, 150,000,000 shares authorized, 50,302,000 issued		50		50
Additional paid-in capital		752,704		748,569
Treasury stock, at cost; 66,831 and no shares at June 30, 2006 and December 31, 2005, respectively.		(1,246)		-
Accumulated other comprehensive loss		(11,852)		(50,731)
Retained Earnings		37,025		17,535
Total stockholders' equity		776,681		715,423
Total liabilities and stockholders' equity	$	1,134,562	$	1,119,269

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

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Rosetta Resources Inc.
Consolidated/Combined Statements of Operations
(In thousands, except per share amounts)
(Unaudited)

	Successor-Consolidated	Predecessor-Combined	Successor-Consolidated	Predecessor-Combined
	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues:				
Natural gas sales	$ 53,677	$ 6,895	$ 110,407	$ 13,637
Oil sales	9,699	4,168	17,508	8,166
Oil and natural gas sales to affiliates	-	42,176	-	81,952
Other revenue	5	37	10	76
Total revenues	63,381	53,276	127,925	103,831
Operating Costs and Expenses:				
Lease operating expense	8,323	9,092	17,881	16,629
Depreciation, depletion, and amortization	25,601	15,555	49,668	30,679
Exploration expense	-	926	-	2,355
Dry hole costs	-	1,886	-	1,962
Treating and transportation	831	1,030	1,726	1,998
Affiliated marketing fees	-	474	-	913
Marketing fees	484	-	1,108	-
Production taxes	1,626	1,567	3,323	2,755
General and administrative costs	7,078	6,332	16,329	9,677
Total operating costs and expenses	43,943	36,862	90,035	66,968
Operating income	19,438	16,414	37,890	36,863
Other (income) expense				
Interest expense with affiliates, net of interest capitalized	-	3,378	-	6,995
Interest expense, net of interest capitalized	4,371	-	8,503	-
Interest income	(1,115)	(263)	(2,252)	(516)
Other expense, net	152	303	177	207
Total other expense	3,408	3,418	6,428	6,686
Income before provision for income taxes	16,030	12,996	31,462	30,177
Provision for income taxes	6,066	4,977	11,972	11,496
Net income	$ 9,964	$ 8,019	$ 19,490	$ 18,681
Earnings per share:				
Basic	$ 0.20	$ 0.16	$ 0.39	$ 0.37
Diluted	$ 0.20	$ 0.16	$ 0.39	$ 0.37

Weighted average shares outstanding:				
Basic	50,229	50,000	50,175	50,000
Diluted	50,370	50,160	50,361	50,160

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

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Rosetta Resources Inc.
Consolidated/Combined Statements of Cash Flows
(In thousands)
(Unaudited)

	Successor-Consolidated	Predecessor-Combined
	Six Months Ended June 30,	
	2006	2005
Cash flows from operating activities		
Net income	$ 19,490	$ 18,681
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	49,668	30,679
Affiliate interest expense	-	(6,995)
Deferred income taxes	11,723	2,874
Amortization of deferred loan fees recorded as interest expense	590	-
Income from unconsolidated investments	(112)	(161)
Stock compensation expense	3,322	-
Other non-cash charges	-	99
Change in operating assets and liabilities:		
Accounts receivable	15,121	2,378
Accounts receivable from affiliates	-	6,298
Income taxes receivable	6,000	-
Other Assets	(2,624)	2,563
Long-term accounts receivable	934	-
Royalties payable	(8,707)	(1,406)
Accounts payable	3,411	(4,494)
Interest payable	(133)	-
Income taxes payable	-	8,622
Other current liabilities	(5,252)	241
Net cash provided by operating activities	93,431	59,379
Cash flows from investing activities		
Purchases of property and equipment	(99,563)	(32,202)
Disposals of property and equipment	36	1,447
Deposits	25	-
Other	(14)	110
Net cash used in investing activities	(99,516)	(30,645)
Cash flows from financing activities		
Equity offering transaction fees	268	-
Notes payable to affiliates	-	(27,239)
Proceeds from issuances of common stock	296	-
Stock-based compensation excess tax benefit	249	-
Purchases of treasury stock	(1,246)	-
Net cash used in financing activities	(433)	(27,239)
Net (decrease) increase in cash	(6,518)	1,495
Cash and cash equivalents, beginning of period	99,724	-
Cash and cash equivalents, end of period	$ 93,206	$ 1,495

Supplemental non-cash disclosures:			
Capital expenditures included in accrued liabilities	$	2,281	-

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

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Rosetta Resources Inc.

Notes to Consolidated/Combined Financial Statements (unaudited)

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, "the Company") was formed in June 2005. The Company ("Successor") is engaged in oil and natural gas exploration, development, production, and acquisition activities in the United States. The Company's main operations are concentrated in the Sacramento Basin of California, Lobo and Perdido Trends in South Texas, the Gulf of Mexico and the Rocky Mountains.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of only normal recurring adjustments, necessary for a fair presentation of the financial statements have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America.

These financial statements and notes should be read in conjunction with the Company's audited consolidated/combined financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2005.

Certain reclassifications of prior year balances have been made to conform such amounts to corresponding 2006 classifications. These reclassifications have no impact on net income.

(2) Acquisition of Calpine Oil and Natural Gas Business

On July 7, 2005, the Company acquired substantially all of the oil and natural gas business of Calpine Corporation and certain of its subsidiaries (collectively, "Calpine" or "Predecessor"), excluding certain non-consent properties described below, for approximately $910 million. This acquisition (the "Acquisition") was funded with the issuance of common stock totaling $725 million and $325 million of debt from our credit facilities. The transaction was accounted for under the purchase method in accordance with SFAS 141. The results of operations were included in the Company's financial statements effective July 1, 2005 as the operating results in the intervening period were not significant. The purchase price in the Acquisition was calculated as follows:

Cash from equity offering	$	725,000
Proceeds from revolver		225,000
Proceeds from term loan		100,000
Other purchase price costs		(53,389)
Transaction adjustments (purchase price adjustments)		(11,556)
Transaction adjustments (non-consent properties)		(74,991)
Initial purchase price	$	910,064

Other purchase price costs relate primarily to professional fees of $3.9 million and other direct transaction costs of $49.5 million.

The transaction adjustments (purchase price adjustments) referred to above are an amount agreed upon by Calpine and the Company to cover potential costs and/or revenues that will be adjusted to actual upon the determination of the final settlement amount for the transaction.

Transaction adjustments (non-consent properties) referred to above relate to properties which Calpine determined required third party consents or waivers of preferential purchase rights in order to effect the transfer of title from Calpine to the Company or to Calpine entities acquired by the Company in the Acquisition (collectively, “Non-Consent Properties”). At July 7, 2005, the Company withheld approximately $75 million of the purchase price with respect to the Non-Consent Properties. A third party exercised a preferential right to purchase certain Non-Consent Properties. Such properties will not be conveyed to the Company, and the purchase price will be reduced by approximately $7.4 million. Despite Calpine’s bankruptcy filing, management believes that it remains likely that conveyance to the Company of substantially all of the remaining Non-Consent Properties will occur. Upon conveyance of the remaining Non-Consent Properties, approximately $68 million, being the balance of the additional purchase price, will be paid to Calpine and will be incremental to the purchase price of $910 million. The Company has excluded the effects of the operating results for the Non-Consent Properties from the Company's actual results for the six months ended June 30, 2006. If the assignment of the remaining Non-Consent Properties does not occur, the portion of the purchase price the Company withheld pending obtaining consent or waivers for these properties will be available to the Company for general corporate purposes or to acquire other properties.

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

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

The purchase price allocation is preliminary in nature and is subject to change based upon the manner in which the parties resolve the negotiation associated with the Company's revised Final Settlement Statement pertaining to the Acquisition that was delivered to Calpine on May 12, 2006. In addition to the $68 million payable to Calpine if and when title is obtained by the Company for the remaining Non-Consent Properties, the Company's revised Final Settlement Statement includes the proposed payment to Calpine of approximately $12 million as a true-up of purchase price adjustments arising from net revenues that were estimated and withheld at the closing of the Acquisition.

The unaudited pro forma information for the three and six months ended June 30, 2005 assumes the acquisition of Calpine's domestic oil and natural gas business and the related financings occurred on January 1, 2004. We believe the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions. The unaudited pro forma financial statements do not purport to represent what the Company's results of operations would have been if such transactions had occurred on such date.

	Three Months Ended June 30, 2005		Six Months Ended June 30, 2005	
	(In thousands, except per share amounts) (Unaudited)			
Revenues	$	53,276	$	103,831
Net income		4,157		12,115
Basic earnings per common share		0.08		0.24
Diluted earnings per common share	$	0.08	$	0.24

(3) Summary of Significant Accounting Policies

The Company has provided discussion of significant accounting policies, estimates and judgments in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

Principles of Consolidation/Combination and Basis of Presentation. The Predecessor combined financial statements for the three and six months ended June 30, 2005 have been prepared from the historical accounting records of the domestic oil and natural gas business of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and natural gas business. The domestic oil and natural gas business of Calpine was separately accounted for and managed through direct and indirect subsidiaries of Calpine. The combined financial information included herein includes certain allocations based on the historical activity levels to reflect the combined financial statements in accordance with accounting principles generally accepted in the United States of America and may not necessarily reflect the financial position, results of operations and cash flows of the Company in the future or as if the Company had existed as a separate, stand-alone business during the period presented. The allocations consist of general and administrative expenses such as employee payroll and related benefit costs and building lease expense, which were incurred on behalf of Calpine. The allocations have been made on a reasonable basis and have been consistently applied for the periods presented.

The accompanying consolidated financial statements as of June 30, 2006 and December 31, 2005 and for the three and six months ended June 30, 2006 contain the accounts of Rosetta Resources Inc. and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

Property, Plant, and Equipment, Net. In connection with the Company’s separation from Calpine, the Company adopted the full cost method of accounting for oil and natural gas properties beginning July 1, 2005. Under the full cost method, all costs incurred in acquiring, exploring and developing properties within a relatively large geopolitical cost center are capitalized when incurred and are amortized as mineral reserves in the cost center are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with offshore U.S. operations, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at

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which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of whatever reserves ultimately result from the efforts as a whole, and are thus associated with the Company's reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $0.9 million and $1.7 million of internal costs for the three and six months ended June 30, 2006, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment rather than amortized. Upon evaluation, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally included in the full cost pool unless a significant portion of the pool is sold.

Capitalized costs and estimated future development costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. The Company assesses the impairment for oil and natural gas properties for the full cost pool quarterly using a ceiling test to determine if impairment is necessary. Specifically, the net unamortized costs for each full cost pool less related deferred income taxes should not exceed the following: (a) the present value, discounted at 10%, of future net cash flows from estimated production of proved oil and gas reserves plus (b) all costs being excluded from the amortization base plus (c) the lower of cost or estimated fair value of unproved properties included in the amortization base less (d) the income tax effects related to differences between the book and tax basis of the properties involved. The present value of future cash flows is based on current prices, with consideration of price changes only to the extent provided by contractual arrangements, as of the latest balance sheet presented. The full cost ceiling test takes into account the prices of qualifying cash flow hedges in calculating the current price of the quantities of the future production of oil and gas reserves covered by the hedges as of the balance sheet date. In addition, the effects of using cash flow hedges in calculating the ceiling test for the portion of future oil and gas production being hedged has been consistently applied in all reporting periods. Asset cost in excess of the present value of reserves are charged to expense during the period that the excess occurs. Application of the ceiling test is required for quarterly reporting purposes, and any write-downs are not reinstated even if the cost ceiling subsequently increases by year-end. No ceiling test write-down was recorded for the three or six months ended June 30, 2006 (Successor).

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

Calpine assessed the impairment for oil and natural gas properties on a field by field basis periodically (at least annually) to determine if impairment of such properties was necessary. Management utilized its year-end reserve report prepared by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc., and related market factors to estimate the future cash flows for all proved developed (producing and non-producing) and proved undeveloped reserves. Property impairments occurred if a field discovered lower than anticipated reserves, reservoirs produced at a rate below original estimates or if commodity prices fell below a level that significantly affected anticipated future cash flows on the property. Proved oil and natural gas property values were reviewed when circumstances suggested the need for such a review and, if required, the proved properties were written down to their estimated fair market value based on proved reserves and other market factors. Unproved properties were reviewed quarterly to determine if there was impairment of the carrying value, with any such impairment charged to expense in the period. No impairment charge was recorded for the three or six months ended June 30, 2005 (Predecessor).

Stock-Based Compensation.

On January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) “Share-Based Payments” (“SFAS-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. The Company adopted this statement using the modified version of the prospective application (modified prospective application). Under the modified prospective application, compensation cost for the portion of awards for which the employee’s requisite service has not been rendered that are outstanding as of January 1, 2006 must be recognized as the requisite service is rendered on or after that date. The compensation cost for that portion of awards shall be based on the original fair market value of those awards on the date of grant as calculated for recognition under SFAS 123. The compensation cost for these earlier awards shall be attributed to periods beginning on or after January 1, 2006 using the attribution method that was used under SFAS 123.

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The adoption of the new standard did not have a significant impact on the Consolidated Balance Sheet with a decrease in retained earnings and an offsetting increase in additional paid-in capital. On the Consolidated/Combined Statement of Operations, the adoption of SFAS-123R resulted in decreases in both income before income taxes and net income of $1.5 million and $0.9 million, respectively, for the three months ended June 30, 2006 (Successor) and $3.3 million and $2.0 million, respectively, for the six months ended June 30, 2006 (Successor). The effect on net income per share for basic and diluted was a reduction $0.02 and $0.04 for the three and six months ended June 30, 2006 (Successor), respectively. See Note 10 of the notes to the Consolidated/Combined Financial Statements for additional disclosure.

Prior to the adoption of SFAS-123R, the Company presented all tax benefit deductions resulting from the exercise of stock options as operating cash flows in the accompanying Consolidated/Combined Statement of Cash Flows. SFAS-123R requires the cash flows that result from tax deductions in excess of the compensation expense recognized as an operating expense in 2006 and reported in pro forma disclosures prior to 2006 for those stock options (excess tax benefits) be classified as financing cash flows. The excess tax benefit for the three and six months ended June 30, 2006 (Successor) in the amount of $0.2 million that is now classified as financing cash flows would have been classified as an operating cash flows prior to the adoption of SFAS-123R.

Recent Accounting Developments

Accounting Changes and Error Corrections. In May 2005 the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3* (“SFAS 154”), which changes the requirements for the accounting for and the reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principles. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of this Statement did not impact the Company’s consolidated financial position, results of operations or cash flows.

Accounting for Certain Hybrid Financial Instruments. In February 2006 , the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Instruments-an amendment of FASB Statements 133 and 140,* which is effective for all financial instruments acquired or issued after the beginning of an entity’s first fiscal year that begins after September 15, 2006. The statement improves financial reporting by eliminating the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. The Statement also improves financial reporting by allowing a preparer to elect fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated, if the holder elects to account for the whole instrument on a fair value basis. The adoption of this Statement is not expected to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

Accounting for Uncertainty in Income Taxes. In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (“FIN 48”). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, “Accounting for Income Taxes.” FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this Interpretation is not expected to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

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(4) Property, Plant and Equipment

The Company’s total property and equipment consists of the following:

	June 30, 2006	December 31, 2005
	(In thousands)	
Proved properties	$ 1,045,263	$ 951,968
Unproved properties	29,379	21,217
Other	3,393	2,912
Total	1,078,035	976,097
Less: accumulated depreciation, depletion, and amortization	(89,480)	(40,161)
	$ 988,555	$ 935,936

Included in the Company’s oil and gas properties are asset retirement obligations of $9.2 million and $9.1 million as of June 30, 2006 and December 31, 2005, respectively.

At June 30, 2006 and December 31, 2005, the Company excluded the following capitalized costs from depletion, depreciation and amortization:

	June 30, 2006	December 31, 2005
Onshore:	(In thousands)	
Development cost	$ 1,475	$ 1,716
Exploration cost	5,651	5,212
Acquisition cost of undeveloped acreage	24,777	19,684
Capitalized interest	1,219	555
Total	33,122	27,167
Offshore:		
Exploration cost	7,077	2,407
Acquisition cost of undeveloped acreage	3,344	950
Capitalized interest	39	28
Total	10,460	3,385
Total costs excluded from depreciation, depletion, and amortization	$ 43,582	$ 30,552

In April 2006, the Company acquired certain oil and gas producing non-operated properties located in Duval, Zapata, and Jim Hogg Counties, Texas and Escambia County in Alabama from Contango Oil and Gas for $11.6 million in cash.

(5) Commodity Hedging Contracts and Other Derivatives

As of June 30, 2006, the Company had the following financial fixed price swaps outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

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Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Underlying Prices MMBtu	Total of Proved Natural Gas Production Hedged (1)	Fair Market Value Gain/(Loss) (In thousands)
2006	Swap	Cash flow	45,000	8,280,000	$ 7.92	46%	$ 11,870
2007	Swap	Cash flow	36,300	13,249,500	7.62	33%	(12,927)
2008	Swap	Cash flow	30,876	11,300,616	7.30	27%	(12,851)
2009	Swap	Cash flow	26,141	9,541,465	6.99	26%	(9,941)
				42,371,581			$ (23,849)

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

As of June 30, 2006, the Company had the following costless collar transactions outstanding with associated notional volumes and contracted ceiling and floor prices that represent hedge prices at various market locations:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor Price MMBtu	Average Ceiling Price MMBtu	Fair Market Value Gain/(Loss) (In thousands)
2006	Costless Collar	Cash flow	10,000	1,840,000	$ 8.825	$ 14.000	$ 4,733

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

The Company’s current cash flow hedge positions are with counterparties who are lenders in the Company's credit facilities. This allows the Company to securitize any margin obligation resulting from a negative change in fair market value of the derivative contracts in connection with the Company's credit obligations and eliminate the need for independent collateral postings. As of June 30, 2006, the Company had no deposits for collateral.

The following table sets forth the results of third party hedge transactions for the respective period for the Consolidated Statement of Operations:

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
Natural Gas		
Quantity settled (MMBtu)	5,005,000	9,955,000
Increase in natural gas sales revenue (In thousands)	$ 9,127	$ 10,690

The Company expects to reclassify gains of $6.1 million to earnings from the balance in Accumulated Other Comprehensive Loss during the next twelve months.

At June 30, 2006, the Company had a derivative instrument current asset of $9.8 million and no derivative instruments under current liabilities on the Consolidated Balance Sheet. The derivative instrument assets related to commodities represent the difference between hedged prices and market prices on hedged volumes of the commodities as of June 30, 2006. Hedging activities related to cash settlements on commodities increased revenues by $9.1 million and $10.7 million for the three and six months ended June 30, 2006 (Successor).

Gains and losses related to ineffectiveness and derivative instruments not designated as hedging instruments are included in other income (expense). There was no ineffectiveness related to cash-flow hedges recorded for the three and six months ended June 30, 2006 (Successor). There were no gains related to derivative instruments not designated as hedged instruments for the three and six months ended June 30, 2005 (Predecessor) as no derivative instruments existed.

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The Company did not enter into any new derivative instruments during the first or second quarters of 2006.

(6) Comprehensive Income

The Company's total comprehensive income (loss) is shown below. For 2005, the Predecessor did not have transactions affecting comprehensive income.

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
	(In thousands)	
Net income	$ 9,964	$ 19,490
Change in fair value of derivative hedging instruments	21,648	73,398
Hedge settlements reclassified to income	(9,127)	(10,690)
Tax provision related to hedges	(4,758)	(23,829)
Comprehensive Income	$ 17,727	$ 58,369

(7) Long-Term Debt

The Company's credit facilities consist of a four-year senior secured revolving line of credit of up to $400.0 million with a borrowing base of $325.0 million and a five-year $75.0 million senior second lien term loan. All amounts drawn under the revolver are due and payable on July 7, 2009. The principal balance associated with the senior secured lien term loan is due and payable on July 7, 2010.

On June 30, 2006, the Company had outstanding borrowings and letters of credit of $240.0 million and $1.0 million, respectively. Net borrowing availability was $159.0 million at June 30, 2006. The Company was in compliance with all covenants at June 30, 2006.

(8) Asset Retirement Obligation

Activity related to the Company's asset retirement obligation (ARO) is as follows:

	Six Months Ended June 30, 2006 (In thousands)
ARO as of January 1, 2006	$ 9,467
Liabilities incurred during period	98
Liabilities settled during period	(14)
Accretion expense	385
Other Adjustments	(4)
ARO as of June 30, 2006	$ 9,932

Of the total ARO, approximately $0.4 million is classified as a current liability at June 30, 2006.

(9) Commitment and Contingencies

The Company is party to various oil and natural gas litigation matters arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters. Management does not believe any such matters will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Calpine Bankruptcy

Calpine Corporation 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 "Court) on December 20, 2005. Calpine Energy Services, L.P., which filed for bankruptcy, has continued to make the required deposits into the Company's margin account and to timely pay for natural gas production it purchases from the Company's subsidiaries under various natural gas supply agreements. As part of the Acquisition, Calpine and the Company entered into a Transition Services Agreement, pursuant to which services were to be provided to the Company through July 6, 2006. Calpine and certain of its subsidiaries have generally continued to provide the services requested by the Company under the Transition Services Agreement. Additionally, Calpine Producer Services, L.P., which filed for bankruptcy, generally is performing its obligations under the Marketing and Services Agreement with the Company.

There remains the possibility, however, that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the Purchase and Sale Agreement and interrelated agreements concurrently executed therewith, dated July 7, 2005, by and among Calpine, the Company, and various other signatories thereto (collectively, 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 (iii) the ultimate disposition of the remaining Non-Consent Properties (and related royalty revenues). Calpine has specific obligations to the Company under the Purchase Agreement relating to these matters, and also has "further assurances" duties to the Company under the Purchase Agreement.

In addition, as to certain of the other oil and natural gas properties the Company purchased from Calpine in the Acquisition and for which payment was made on July 7, 2005, the Company will seek additional documentation from Calpine to eliminate any open issues in the Company's title or resolve any issues as to the clarity of the Company's 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 the Company as qualified assignee and operator, which is typically required even though in most cases Calpine has already conveyed the properties to the Company 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. The Company remains hopeful that the Company will continue to work cooperatively with Calpine to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all properties acquired by the Company in the Acquisition, Calpine contractually agreed to provide the Company with such further assurances as the Company 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, the Company will pursue all available remedies, including but not limited to a declaratory judgment to enforce the Company's rights and actions to quiet title. After pursuing these matters, if the Company experiences a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to the Company, an outcome the Company's management considers to be remote, then the Company could experience losses which could have a material adverse effect on the Company's consolidated 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 gas leases Calpine has previously sold or agreed to sell to the Company in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to the Company 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 the Company or Calpine, but the Company understands 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 gas leases. The Company disputes Calpine's contention that it may have an interest in any significant portion of these oil and gas leases and intends to take the necessary steps to protect all of the Company's rights and interest in and to the leases. On July 7, 2006, the Company filed an objection in response to Calpine's motion, wherein the Company asserted that oil and gas leases constitute interests in real property that are not subject to "assumption" under the Bankruptcy Code. In the objection the Company 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 the Company in July 2005, and the Minerals Management Service has subsequently recognized the Company 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 the Company's objection, the Company also urged the 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 Court that the parties seek arbitration (or at least mediation) to complete the following:

- Calpine's conveyance of the Non Consent Properties to the Company;

- 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 the Company has already paid Calpine; and

- Resolution of the final amounts the Company is to pay Calpine, which the Company has concluded are approximately $80 million, consisting of roughly $68 million for the Non Consent Properties and approximately $12 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:

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- 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 Department of Interior) and the State of California (and managed by the California State Lands Commission). Calpine and the Department of Justice agreed to an extension of the existing deadline to November 15, 2006 to assume such Oil and Gas Leases under Section 365 of the Bankruptcy Code, to the extent the Oil and Gas Leases are leases subject to Section 365. The effect of these actions is to render the objection of the Company inapplicable at this time; and

- The Court also encouraged Calpine and the Company 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, the Company 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 cannot presently be determined. The Company continues 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.

The Company continues to believe that it is unlikely that any challenges by the Calpine debtors or their creditors to the fairness of the Acquisition would be successful. However, there can be no assurance that Calpine, its creditors or interest holders may not challenge the fairness of some or all of the Acquisition. For a number of reasons, including the Company's understanding of the process that Calpine followed in allowing market forces to set the purchase price for the Acquisition, the Company believes that it is unlikely that any challenge to the fairness of the Acquisition would be successful.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. The Company performed an environmental remediation study for two sites in California and correspondingly, recorded a liability, which at June 30, 2006 and December 31, 2005 was $0.1 million and $0.7 million, respectively. The Company does not expect that the outcome of our environmental matters discussed above will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Participation in a Regional Carbon Sequestration Partnership

The Company has made preliminary preparations in connection with the Company participating in the United States Department of Energy's ("DOE") Regional Carbon Sequestration Partnership program ("WESTCARB") with the California Energy Commission and the University of California, Lawrence Berkeley Laboratory. The Company has been selected by the DOE for this project. Under WESTCARB, the Company would be required to drill a carbon injection well, recondition an idle well for use as an observation well and provide WESTCARB with certain proprietary well data and technical assistance related to the evaluation and injection of carbon dioxide into a suitable natural gas reservoir in the Sacramento Basin. The Company's maximum contribution to WESTCARB is $1.0 million and will be limited to 20% of the total contributions to the project. The Company will not have any obligation under the WESTCARB project until it has entered into an acceptable contract and the project has obtained proper and necessary local, state and federal regulatory approvals, land use authorizations and third party property rights. No accrual was recorded at June 30, 2006 as the study is still in the preliminary stage.

(10) Stock-Based Compensation

Adoption of SFAS-123R

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

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

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fair value method of accounting prescribed by SFAS No. 123 had been applied.

Effective January 1, 2006, the Company began accounting for stock-based compensation under SFAS-123R, whereby the Company records stock-based compensation expense based on the fair value of awards described below. Stock-based compensation expense recorded for all share-based payment arrangements for the three and six months ended June 30, 2006 (Successor) was $1.5 million and $3.3 million, with a tax benefit of $0.6 million and $1.2 million, respectively. For the three and six months ended June 30, 2005 (Predecessor), stock-based compensation expense recorded was $0.1 million and $0.2 million with a tax benefit of $0.01 million and $0.1 million, respectively. The remaining compensation expense associated with total unvested awards as of June 30, 2006 was $10.3 million and will be recognized over a weighted average period of 1.29 years.

Successor

2005 Long-Term Incentive Plan

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

Stock Options

The Company has granted stock options under its 2005 Long-Term Incentive Plan. Options generally expire ten years from the date of grant. The exercise price of the options can not be less than the fair market value per share of the Company's common stock on the grant date.

The weighted average fair value at date of grant for options granted during the six months ended June 30, 2006 (Successor) and 2005 (Predecessor) was $10.74 and $1.27 per share, respectively. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	Successor Six Months Ended June 30, 2006	**Predecessor Six Months Ended June 30, 2005**
Expected option term (years)	6.5	2.5
Expected volatility	56.65%	58.00%
Expected dividend rate	0.00%	0.00%
Risk free interest rate	4.33% - 5.15%	3.62%

The Company has assumed an annual forfeiture rate of 5 % for the awards granted in 2006 based on the Company’s history for this type of award to various employee groups. Compensation expense is recognized ratably over the requisite service period and immediately for retirement-eligible employees.

The following table summarizes information related to outstanding and exercisable options held by the Company’s employees at June 30, 2006:

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	Shares	Weighted Average Exercise Price Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at the December 31, 2005	706,550	$ 16.28		
Granted	213,950	17.94		
Exercised	(18,500)	16.02		
Forfeited	(33,625)	16.28		
Outstanding at June 30, 2006	868,375	$ 16.70	9.21	$ 201
Options Exercisable at June 30, 2006	210,512	$ 16.34	9.17	$ 56

Stock-based compensation expense recorded for stock option awards for the three and six months ended June 30, 2006 (Successor) is $1.0 million and $1.5 million, respectively. Stock-based compensation expense recorded for stock option awards for the three and six months ended June 30, 2005 (Predecessor) is $0.1 million and $0.2 million, respectively. Unrecognized expense as of June 30, 2006 for all outstanding stock options is $5.7 million.

The total intrinsic value of options exercised during the six months ended June 30, 2006 was $0.1 million. For the three and six months ended June 30, 2005, the Predecessor did not have any options exercised. The fair value of awards vested for the six months ended June 30, 2006 was $5.2 million.

Restricted Stock

The Company has granted stock under its 2005 Long-Term incentive Plan with a maximum contractual life of three years. The fair value of restricted stock grants is based on the value of the Company’s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company also assumes an annual forfeiture rate of 5 % for these awards based on the Company’s history for this type of award to various employee groups.

The following table summarizes information concerning restricted stock held by the Company’s employees at June 30, 2006:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2005	581,900	$ 16.27
Granted	107,800	17.79
Vested	(280,000)	16.07
Forfeited	(23,500)	16.28
Non-vested shares outstanding at June 30, 2006	386,200	$ 16.83

The non-vested restricted stock outstanding at June 30, 2006 vests at a rate of 25% on the first anniversary of the date of grant, 25% on the second anniversary and 50% on the third anniversary. The restrictions on 270,000 shares lapsed on the day after the Company’s effective date of its recently completed initial public offering in February 2006 and therefore vested in the first quarter of 2006.

Stock-based compensation expense recorded for restricted stock awards for the three and six months ended June 30, 2006 was $0.5 million and $1.8 million, respectively. Unrecognized expense as of June 30, 2006 for all outstanding restricted stock awards is $4.6 million.

Predecessor

Retirement Savings Plan

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

2000 Employee Stock Purchase Plan

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

1996 Stock Incentive Plan

The Predecessor adopted the 1996 Stock Incentive Plan ("SIP") in September 1996 in which certain of the Company's employees were eligible to participate. The SIP succeeded the Predecessor's previously adopted stock option program. Under the SIP, the option exercise price generally equaled the stock's fair market value on date of grant. The SIP options generally vested ratably over four years and expired after 10 years. As of June 30, 2005, the amount of shares outstanding under the 1996 incentive plan were 754,284.

(11) Earnings Per Share

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

The following is a calculation of basic and diluted weighted average shares outstanding:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands)			
Basic weighted average number of shares outstanding	50,229	50,000	50,175	50,000
Dilution effect of stock option and awards at the end of the period	141	160	186	160

Diluted weighted average number of shares outstanding	50,370	50,160	50,361	50,160
Stock awards and shares excluded from diluted earnings per share due to anti-dilutive effect	206	-	154	-

(12) Operating Segments

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

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Geographic Area Information

The Company owns oil and natural gas interests in eight main geographic areas all within in the United States. Geographic revenue and property, plant and equipment information below for the three and six months ended June 30, 2006 and 2005 are based on physical location of the assets at the end of each period.

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30,		Six Months Ended June 30,	
	2006 (1)	2005	2006 (1)	2005
Oil and Natural Gas Revenue	(In thousands)			
California	$ 15,710	$ 21,203	$ 36,100	$ 43,385
Lobo	13,673	13,877	29,082	26,474
Perdido	6,962	6,508	16,784	12,380
State Waters	2,142	2,331	5,289	2,345
Other Onshore	8,315	4,245	12,175	7,662
Gulf of Mexico	6,394	4,553	15,921	10,542
Rockies	622	86	964	161
Mid-Continent	431	472	910	842
Other	5	1	10	40
	$ 54,254	$ 53,276	$ 117,235	$ 103,831

(1) Excludes the effects of hedging.

	Successor	
	June 30, 2006 (2)	December 31, 2005 (2)
	(In thousands)	
Oil and Natural Gas Properties		
California	$ 408,493	$ 386,513
Lobo	378,302	368,276
Perdido	38,345	25,983
State Waters	18,622	12,067
Other Onshore	98,675	75,737
Gulf of Mexico	92,763	77,416
Rockies	31,494	21,224
Mid-Continent	7,948	5,969
Other	3,393	2,912
	$ 1,078,035	$ 976,097

(2) Oil and natural gas properties at June 30, 2006 and December 31, 2005 are reported gross. Under the full cost method of accounting for oil and gas properties, depreciation, depletion and amortization is not allocated to properties.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements, other than statements of historical fact, included in this report, are forward-looking statements. In some cases, you can identify a forward-looking statement by terminology such as “may”, “could”, “should”, “expect”, “plan”, “project”, “intend”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “pursue”, “target” or “continue”, the negative of other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Management’s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties, see Item 1A. Risk Factors in our annual report on Form 10-K for the year ended December 31, 2005. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to various factors, including:

- The timing and extent of changes in commodity prices, particularly natural gas;
- Various drilling and exploration risks that may delay or prevent commercial operation of new wells;
- Economic slowdowns that can adversely affect consumption of oil and natural gas by businesses and consumers;
- Resources expended in connection with Calpine’s bankruptcy including our increased costs for lawyers, consultant experts and related expenses, as well as the lost opportunity costs associated with its internal resources dedicated to these matters;
- Uncertainties that actual costs may be higher than estimated;
- Factors that impact the exploration of oil or natural gas resources, such as the geology of a resource, the total amount and costs to develop recoverable reserves, and legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas;
- Uncertainties associated with estimates of oil and natural gas reserves;
- Our ability to access the capital markets on attractive terms or at all;
- Refusal by or inability of our current or potential counterparties or vendors to enter into transactions with us or fulfill their obligations to us;
- Our inability to obtain credit or capital in desired amounts or on favorable terms;
- Present and possible future claims, litigation and enforcement actions;
- Effects of the application of regulations, including changes in regulations or the interpretation thereof;

- Availability of processing and transportation;
- Potential for disputes with mineral lease and royalty owners regarding calculation and payment of royalties, including basis of pricing, adjustment for quality, measurement and allowable costs and expenses;
- Developments in oil-producing and natural gas-producing countries;
- Competition in the oil and natural gas industry; and
- Adverse weather conditions, hurricanes, tropical storms, earthquakes, mud slides, flooding and other natural disasters which may occur in areas of the United States in which we have operations, including the Federal waters of the Gulf of Mexico, as well as new energy package insurance coverage limitations related to any single named windstorm; and uncertainty with respect to potential environmental, health and safety liabilities.

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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 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 domestic oil and natural gas business of Calpine Corporation and its affiliates. Our main operations are concentrated in the Sacramento Basin of California, 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 gas properties as "Predecessor". Additionally, we sometimes refer to our acquisition of Calpine's domestic oil and natural gas business as the "Acquisition".

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

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce our reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. The permitting and approval process has been more difficult in recent years than in the past due to increased activism from environmental and other groups and has extended the time it takes us to receive permits. 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

In the first six months of 2006, we produced 15.7 Bcfe with average revenue of $8.15 per Mcfe. Our natural gas production for the six months ended June 30, 2006 was 14.0 Bcf and our oil production for the same period was 270.8 MBbls. Our average natural gas prices were $7.89 per Mcf and average oil prices for the same period were $64.65 per Bbl. For the six months ended June 30, 2006, we had revenues of $127.9 million including the effects of hedging with net income of $19.5 million and earnings per share of $0.39.

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.

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- 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.

- 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 $1.4 million in lost sales at production rates and prices as of June 30, 2006.

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

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 those 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, in each case where we obtained the required consents or waivers.

The approximate allocated value under the Purchase Agreement for the portion of the Non-Consent Properties subject to a preferential right to purchase is $7.1 million. We have retained $7.4 million of the purchase price under the Purchase Agreement for the Non-Consent Properties subject to preferential rights to purchase, which total amount includes approximately $0.3 million for a property which was transferred to us but will be transferred to the appropriate third party under an exercised preferential purchase right. These properties will not be conveyed to us and we have retained the $7.4 million previously withheld pending receipt of waivers of the preferential rights to purchase.

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 preferential rights 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 these remaining Non-Consent Properties 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 remaining Non-Consent Properties, 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 six months ended June 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 preferential rights 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 $7.4 million, previously withheld for that portion of the Non-Consent Properties subject to preferential rights 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 such as 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

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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 we will continue to work cooperatively with Calpine to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all 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 consolidated 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 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 gas leases. We dispute Calpine's contention that it may have an interest in any significant portion of these oil and 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 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 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 gas properties for which we have already paid Calpine; and
- Resolution of the final amounts we are to pay Calpine, which we have concluded are approximately $80 million, consisting of roughly $68 million for the Non Consent Properties and approximately $12 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 Department of Interior) and the State of California (and managed by the California State Lands Commission). Calpine and the Department of

Justice agreed to an extension of the existing deadline to November 15, 2006 to assume such Oil and Gas Leases under Section 365 of the Bankruptcy Code, to the extent the Oil and Gas Leases are leases subject to Section 365. The effect of these actions is to render our objection inapplicable at this 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. We continue 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

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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.

On January 1, 2006, we adopted the accounting policies described in SFAS No. 123 (revised 2004) “Share-Based Payments” (“SFAS-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-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-123R, this amount was included as a pro forma disclosure in the Notes to the Consolidated Financial Statements. Compensation expense for the three and six months ended June 30, 2006 (Successor) was $1.5 million and $3.3 million, respectively.

In addition, the application of the forfeiture rate in calculating the fair value has changed with the adoption of SFAS-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

In July 2005, we acquired the domestic oil and natural gas business of Calpine Corporation and affiliates. Due to the Acquisition, the results of operations for the three and six months ended June 30, 2006 and 2005 are presented as Successor and Predecessor, Successor comprising the three and six months ended June 30, 2006 and Predecessor comprising the three and six months ended June 30, 2005. These two 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-123R effective January 1, 2006. We believe comparative results of operations for the two periods 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 $63.4 million for the second quarter consists primarily of natural gas sales comprising 85% of total revenue on total volumes of 8.0 Bcfe. For the six months ended June 30, 2006, gas sales comprised 86% of total revenue on total volumes of 15.7 Bcfe.

		Three Months Ended June 30, 2006		Six Months Ended June 30, 2006
	(In thousands, expect per unit amounts)			
Total revenues	$	63,381	$	127,925
Production:				
Gas (Bcf)		7.1		14.0
Oil (MBbls)		143.6		270.8
Total Equivalents (Bcfe)		8.0		15.7
$ per unit:				
Avg. Gas Price per Mcf	$	7.56	$	7.89
Avg. Gas Price per Mcf excluding Hedging		6.28		7.12
Avg. Oil Price per Bbl		67.54		64.65
Avg. Revenue per Mcfe	$	7.92	$	8.15

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Natural Gas. Natural gas sales revenue was $53.7 million, including the effects of hedging, based on total gas production volumes of 7.1 Bcf for the three months ended June 30, 2006. Approximately 80% of the production volumes were from the following three areas: California, Lobo and Perdido. The average natural gas prices were $7.56 per Mcf for the respective period. The effect of hedging on natural gas sales revenue was an increase of $9.1 million for an increase in total price from $6.28 to $7.56 per Mcf.

Natural gas sales revenue was $110.4 million, including the effects of hedging, based on total gas production volumes of 14.0 Bcf for the six months ended June 30, 2006. Approximately 79% of the production volumes were from California, Lobo and Perdido. The average natural gas prices were $7.89 per Mcf for respective period. The effect of hedging on natural gas sales revenue was an increase of $10.7 million for an increase in total price from $7.12 to $7.89 per Mcf.

Crude Oil. Oil revenue was $9.7 million based on production volumes of 143.6 MBbls for the three months ended June 30, 2006. Production volumes were 63.5 MBbls for Gulf of Mexico and 51.6 MBbls for Other Onshore both representing approximately 80% of the total production. The average oil price was $67.54 per Bbl.

Oil revenue was $17.5 million based on production volumes of 270.8 MBbls for the six months ended June 30, 2006. Production volumes were 139.0 MBbls for Gulf of Mexico, 72.2 MBbls for Other Onshore and 23.9 MBbls for Lobo resulting in approximately 87% of the total production. The offshore production volumes were higher than expected due to minimal downtime on most of the offshore wells in High Island and East Cameron. The average oil price was $64.65 per Bbl.

Operating Expenses

The following table presents information about our operating expenses for the three and six months ended June 30, 2006.

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
	(In thousands, expect per unit amounts)	
Lease operating expense	$ 8,323	$ 17,881
Depreciation, depletion and amortization	25,601	49,668
Treating and transportation	831	1,726
Marketing fees	484	1,108
Production taxes	1,626	3,323
General and administrative costs	$ 7,078	$ 16,329
$ per unit:		
Avg. lease operating expense per Mcfe	$ 1.04	$ 1.14
Avg. DD&A per Mcfe	3.20	3.16
Avg. transportation & marketing per Mcfe	0.16	0.18
Avg. production tax expense per Mcfe	0.20	0.21
Avg. G&A per Mcfe	$ 0.88	$ 1.04

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

- *Lease Operating Expense*. Lease operating expense of $8.3 million related directly to oil and natural gas volumes which totaled 8.0 Bcfe for the three months ended June 30, 2006 or costs of $1.04 per Mcfe. The costs included work over cost, ad valorem taxes, insurance, well servicing and equipment rentals.

Lease operating expense of $17.9 million related directly to oil and natural gas volumes which totaled 15.7 Bcfe for the six months ended June 30, 2006 or costs of $1.14 per Mcfe. In addition, lease operating costs were affected by the number of wells that came on-line in South Texas.

- *Depreciation, Depletion, and Amortization.* Depreciation, depletion, and amortization expense for the three and six month period ended was $25.6 million and $49.7 million, respectively, under the full cost method of accounting for oil and natural gas properties. The depletion rate was $3.16 per Mcfe in the second quarter of 2006.

- *General and Administrative Costs*. General and administrative costs for the three and six months ended June 30, 2006 were $7.1 million and $16.3 million net of capitalization of general and administrative costs of $0.9 million and $1.7 million, respectively, as a component of our oil and natural gas properties 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,

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consulting, and auditing fees. In addition, stock compensation expense for the three and six months ended June 30, 2006 of $1.5 million and $3.3 million is recorded in general and administrative costs.

Total Other (income) expense. Other (income) expense is composed of interest expense of $4.4 million and $8.5 million for the three and six months ended June 30, 2006, respectively, and interest income of $1.1 million and $2.3 million for the same periods, respectively. The interest expense is associated with the note payable and interest income is related to the interest earned on the overnight investments of the Company's cash balances.

Provision for Income Taxes. The effective tax rate for the three and six months ended June 30, 2006 was 37.8% and 38.1%, respectively. 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.

Predecessor

Revenues. Total Revenues of $53.3 million and $103.8 million for the three and six months ended June 30, 2005, respectively, consists primarily of natural gas sales comprising 92 % of total revenue. Production volumes for the three and six months ended June 30, 2005 were 7.5 Bcfe and 15.5 Bcfe, respectively. Production volumes were lower than expected due to capital expenditure constraints resulting in reduced drilling activity.

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
	(In thousands, expect per unit amounts)	
Total revenues	$ 53,276	$ 103,831
Production:		
Gas (Bcf)	7.0	14.5
Oil (MBbls)	81.2	163.8
Total equivalents per (Bcfe)	7.5	15.5
$ per unit:		
Avg. Gas Price per Mcf	$ 7.02	$ 6.59
Avg. Oil Price per Bbl	51.33	49.86
Avg. Revenue per Mcfe	$ 7.10	$ 6.70

Natural Gas. Natural gas sales revenue was $49.1 million based on total gas production volumes of 7.0 Bcf for the three months ended June 30, 2005. There were no effects of hedging on the revenue or production amounts as no derivative instruments existed during the three and six months ended June 30, 2005.

Natural gas sales revenue was $95.6 million with 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 South Texas, Lobo with 3.7 Bcf and Perdido with 1.8 Bcf, for 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.

Crude Oil. Oil sales revenue was $4.2 million with oil production of 81.2 MBbls for the three months ended June 30, 2005. The average oil price was $51.33 per Bbl. For the six months ended June 30, 2005 oil sales revenue was $8.2

million with production volumes of 163.8 MBbls with an average price of $49.86 per Bbl. Production volumes were primarily from the Gulf of Mexico region which produced 72.7 MBbls or 44% of oil production.

Operating Expenses

The following table presents information about our operating expenses for the three and six months ended June 30, 2005.

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	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
	(In thousands, expect per unit amounts)	
Lease operating expense	$ 9,092	$ 16,629
Depreciation, depletion and amortization	15,555	30,679
Exploration expense	926	2,355
Dry hole costs	1,886	1,962
Treating and transportation	1,030	1,998
Affiliated marketing fees	474	913
Production taxes	1,567	2,755
General and administrative costs	6,332	9,677
$ per unit:		
Avg. lease operating expense per Mcfe	$ 1.21	$ 1.08
Avg. DD&A (excluding impairments) per Mcfe	2.07	1.98
Avg. transportation & marketing per Mcfe	0.20	0.19
Avg. production tax expense per Mcfe	0.21	0.18
Avg. G&A per Mcfe	$ 0.84	$ 0.63

The operating expenses for the three and six months ended June 30, 2005 are primarily related to the following items:

· *Lease Operating Expense*. Lease operating expense of $9.1 million related directly to oil and natural gas volumes which totaled 7.5 Bcfe for the three months ended June 30, 2005 or costs of $1.21 per Mcfe. The costs included work over cost, ad valorem taxes, insurance, well servicing and equipment rentals. 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.

· *Depreciation, Depletion, and Amortization*. Depreciation, depletion, and amortization expense was $15.6 million and $30.7 million for the three and six months ended June 30, 2005, respectively. The predecessor used the successful efforts method of accounting for oil and natural gas properties during the above periods. The depletion rate was $1.97 per Mcfe for the six months ended June 30, 2005

· *Exploration expense*. Exploration expense was $0.9 million and $2.4 million for the three and six months ended June 30, 2005, respectively, under the successful efforts method of accounting for oil and natural gas properties. The exploration expense was comprised of geological and geophysical salaries and expenses.

· *Production Taxes*. Production taxes are primarily based on wellhead values of production and vary across the different regions. Production taxes as a percentage of natural gas and oil sales were approximately 2.9% and 2.7% for the three and six months ended June 30, 2005, respectively.

· *General and Administrative Costs.* General and administrative costs for the three and six months ended June 30, 2005 were $6.3 million and $9.7 million, which are net of capitalized general and administrative costs of $2.4 million and $3.6 million, respectively. 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.

***Other (income) expense*.** Other (income) expense is comprised of interest expense of $3.4 million and $7.0 million for the three and six months ended June 30, 2005, respectively, and is associated with the intercompany debt with Calpine Corporation.

Provision for Income Taxes. The effective tax rate for the three and six months ended June 30, 2005 was 38.3% and 38.1%, respectively. 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.

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 declined 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. 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. 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, a lien on cash securing the Calpine gas purchase and sale contracts and $15 million of cash on-hand. 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 June 30, 2006, our current ratio was 4.3 and our leverage ratio was 1.4. 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 June 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 June 30, 2006.

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 June 30, 2006. The revised principal balance is due and payable on July 7, 2010.

Cash Flows

	Successor	Predecessor
	Six months ended June 30,	
	2006	2005
	(In thousands)	
Cash flows provided by operating activities	$ 93,431	$ 59,379
Cash flows used in investing activities	(99,516)	(30,645)
Cash flows used in financing activities	(433)	(27,239)
Net (decrease) increase in cash and cash equivalents	$ (6,518)	$ 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

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expenses.

Net cash provided from operating activities for the six months ended June 30, 2006 was $93.4 million generated from total production of 15.7 Bcfe with revenue of $127.9 million and net income of $31.5 million before taxes. Natural gas prices averaged $7.89 per Mcf, including the effects of hedging, and oil averaged $64.65 per Bbl.

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 six months ended June 30, 2006 was $99.5 million primarily relating to the purchases of property and equipment with additional capital expenditures accrued for at quarter end.

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 increases in intercompany notes payable and corresponding repayments of debt.

Net cash used in financing activities for the six months ended June 30, 2006 was $0.4 million primarily related to the purchases of treasury stock of $1.2 million offset by the equity offering transaction fees, proceeds from issuances of common stock and stock-compensation excess tax benefit.

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 six months ended June 30, 2006 were $101.8 million. These capital expenditures were primarily associated with increased drilling activity in California and the Texas State Waters. We believe we have adequate expected cash flows from operations and available borrowings under our revolving credit facility to cover our budgeted capital expenditures.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk primarily related to adverse changes in oil and natural gas prices and interest rates. We use derivative instruments to manage our commodity price risk caused by fluctuating prices. We do not enter into derivative instruments for trading purposes. For information regarding our exposure to certain market risks, see Item 7A. “Quantitative and Qualitative Disclosure About Market Risks” in our annual report filed on Form 10-K for the year ended December 31, 2005. There have been no significant changes in our market risk from what was disclosed in the Form 10-K for the year ended December 31, 2005.

Item 4. Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (“Exchange Act”), as of June 30, 2006. Disclosure controls and procedures are those controls and procedures designed to provide reasonable assurance that the information required to be disclosed in our Exchange Act filings is (1) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission’s rules and forms, and (2) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2006, our disclosure controls and procedures were not effective, at the reasonable assurance level, due to the identification of the material weaknesses in internal control over financial reporting described below. Notwithstanding the material weaknesses described below, we believe our unaudited consolidated financial statements included in this quarterly filing on Form 10-Q fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in accordance with generally accepted accounting principles as applicable to interim reporting.

In preparing our Exchange Act filings, including this quarterly filing on Form 10-Q, we implemented processes and procedures to

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

Material Weaknesses in Internal Control Over Financial Reporting

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. We have identified various deficiencies in internal control over financial reporting. We believe that many of these are attributable to our transition from a subsidiary of a much larger company to a stand alone entity. In connection with the preparation of our unaudited consolidated financial statements and our assessment of the effectiveness of our disclosure controls and procedures as of June 30, 2006 to be included in this Quarterly Report on Form 10-Q to be filed under the Exchange Act, we determined the following specific control deficiencies, which represent material weaknesses in our internal control over financial reporting as of June 30, 2006:

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

b) We did not have effective controls as it relates to the identification and documentation of accounting policies, including selection and application of generally accepted accounting principles used for accounting for select transactions and other activities. This deficiency resulted in a reduced ability to ensure the timely and accurate recording of certain transactions and activities primarily relating to accounting for derivatives and debt modifications. As a result, we did not have sufficient procedures to ensure significant underlying select transactions were appropriately and timely accounted for in the general ledger.

In addition, these material weaknesses could result in a misstatement of substantially all accounts and disclosures which would result in a material misstatement of annual or interim financial statements that would not be prevented or detected. Accordingly, management has concluded that these control deficiencies constitute material weaknesses. These material weaknesses also existed at December 31, 2005 and March 31, 2006.

Remediation Activities

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

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

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

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

4. We employed a certified public accountant from one of the top tier Accounting Firms to be the manager of financial reporting;

5. We employed two supervisory level accountants who have extensive industry experience; and

6. We have made substantial progress on the establishment and documentation of our accounting policies and procedures.

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While we have taken certain actions to address the material weaknesses identified, additional measures may be necessary. These measures will be taken to address the material weaknesses identified to provide reasonable assurance that our internal control over financial reporting is effective.

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

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PART II

OTHER INFORMATION

Item 1. Legal Proceedings

We and our subsidiaries are party to various oil and natural gas litigation matters arising from time to time in 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 financial statements.

We carry insurance with coverage and coverage limits consistent with our assessment of risks in our business and of an acceptable level of financial exposure. Although there can be no assurance that such insurance will be sufficient to mitigate all damages, claims or contingencies, we believe that our insurance provides reasonable coverage for known asserted or unasserted claims. In the event we sustain a loss from a claim and the insurance carrier disputed coverage or coverage limits, we may record a charge in a different period than the recovery, if any, from the insurance carrier.

Calpine Bankruptcy

Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the Court on December 20, 2005. Calpine Energy Services, L.P., which filed for bankruptcy, has continued to make the required deposits into the Company's margin account and to timely pay for natural gas production it purchases from the Company's subsidiaries under various natural gas supply agreements. As part of the Acquisition, Calpine and the Company entered into a Transition Services Agreement, pursuant to which services were to be provided to the Company through July 6, 2006. Calpine and certain of its subsidiaries have generally continued to provide the services requested by the Company under the Transition Services Agreement. Additionally, Calpine Producer Services, L.P., which filed for bankruptcy, generally is performing its obligations under the Marketing and Services Agreement with the Company.

There remains the possibility, however, that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the Purchase and Sale Agreement and interrelated agreements concurrently executed therewith, dated July 7, 2005, by and among Calpine, the Company, and various other signatories thereto (collectively, 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 (iii) the ultimate disposition of the remaining Non-Consent Properties (and related royalty revenues). Calpine has specific obligations to the Company under the Purchase Agreement relating to these matters, and also has "further assurances" duties to the Company under the Purchase Agreement.

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 we will continue to work cooperatively with Calpine to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all 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 our management considers 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 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 gas leases. We dispute Calpine’s contention that it may have an interest in any significant portion of these oil and 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 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 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 definitive agreements with Calpine and proposed to the Court that the parties seek arbitration (or at least mediation) to complete the following:

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- 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 Agreements with respect to certain of the oil and gas properties for which we have already paid Calpine; and

- Resolution of the final amounts we are to pay Calpine, which we have concluded are approximately $80 million, consisting of roughly $68 million for the Non Consent Properties and approximately $12 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 Department of Interior) and the State of California (and managed by the California State Lands Commission). Calpine and the Department of Justice agreed to an extension of the existing deadline to November 15, 2006 to assume such Oil and Gas Leases under Section 365 of the Bankruptcy Code, to the extent the Oil and Gas Leases are leases subject to Section 365. The effect of these actions is to render our objection inapplicable at this 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. We continue 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.

Item 1A. Risk Factors

Other than with respect to the risk factors below, there have been no material changes in our risk factors from those disclosed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005. The following risk factors were disclosed on the Form 10-K and have been updated as of June 30, 2006.

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

Calpine, its creditors and interest holders may challenge the fairness of some or all of the Acquisition.

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

- Transferred its domestic oil and natural gas business to us with the intent of hindering, delaying or defrauding its current or future creditors; or

-

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

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

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.

At the closing of the Acquisition, Calpine agreed to sell but retained title to certain domestic oil and gas properties, subject to obtaining various third party consents or waivers of preferential purchase rights in order to effect transfer of title. In July 2005, as part of the transactions undertaken in connection with closing the Acquisition, we accepted possession of and have since been operating all of the properties for which Calpine retained record legal title. We withheld approximately $75 million from the aggregate purchase price, which was the allocated dollar amount under the Purchase Agreement for the remaining properties. Subsequent to the closing of the Acquisition, with the exception of the properties subject to the preferential right to purchase, we obtained substantially all of the consents to assign for all of these remaining properties for which consents were actually required. Prior to the Calpine bankruptcy, we were prepared to consummate the assignments of these remaining properties, except those subject to the preferential purchase right to purchase. The PV-10 value of these properties at December 31, 2005 was approximately $72.4 million. Based on our internal calculations, we estimate the PV-10 value of these properties as of June 30, 2006 to be approximately $63.7 million. We are prepared to pay Calpine the retained portion of the original purchase price, approximately $68 million, and approximately $12 million in other true-up payment obligations, all upon our receipt from Calpine of record title, free of any encumbrance, for that portion of these properties which are the Non Consent Properties, subject to appropriate adjustment for the net revenues and expenses through December 15, 2005. If the assignment of any remaining properties (including any leases) does not occur, the portion of the purchase price we held back pending consent or waiver will be retained by us and will be available to us for general corporate purposes.

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.

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 we will continue to work cooperatively with Calpine to secure these ministerial governmental approvals and accomplish the curative corrections for all of these properties for which we paid Calpine for, all of the same being covered, we believe, by the further assurances provision of the Purchase Agreement, the exact details for each property involved and how, when and if this will be able to be secured or accomplished continue to remain uncertain at this early stage of Calpine’s bankruptcy.

Additionally, on June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding seeking entry of an order 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 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 Calpine successfully convinces the Court that the oil and natural gas leases are "unexpired leases of non-residential real property," subject to its obligations under the Purchase Agreement, Calpine could require that we take further action or pay further consideration to complete the assignments of these interests or could retain the leases.

Any failure to complete the corrective action necessary to remove title deficiencies with respect to certain of these properties, including failure by Calpine to deliver corrective documentation or failure of the Court to require Calpine to deliver such corrective documentation, could result in a material adverse effect on us if we are not able to receive any offsetting refund of the portion of the purchase price attributable to the properties or if we are required to pay additional consideration.

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 from the operational matters by the Calpine bankruptcy, our business, results of operations, financial position or cash flows could be adversely affected.

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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, 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 liability at a time when we are not able to obtain liability insurance, then our business, results of operations, financial condition, and cash flows could be materially adversely affected.

Environmental, health, and safety liabilities could adversely affect our financial condition.

The oil and natural and natural gas business is subject to environmental, health and safety hazards, such as oil spills, natural gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These hazards could expose us to material liabilities for property damages, personal injuries or other environmental, health and safety harms, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

- Well drilling or work over, operation and abandonment;
- Waste management;
- Land Reclamation;
- Financial assurance under the Oil Pollution Act of 1990; and
- Controlling air, water and waste emissions.

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

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

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

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

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuance of Unregistered Securities

None.

Item 3. Defaults Upon Senior Securities

None.

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

On June 14, 2006 the Company held its Annual Meeting of Shareholders. At the meeting, shareholders voted on election of all of our directors to serve until the next annual meeting of shareholders. The following is a summary of the votes on this item:

	Votes For	Votes Withheld
B.A. "Bill" Berilgen	38,293,539	80,173
Richard W. Beckler	37,771,038	602,674
Donald D. Patteson, Jr.	37,771,038	602,674
D. Henry Houston	37,767,038	606,674
G. Louis Graziadio	33,221,797	5,161,915

Item 5. Other Information

Rosetta reported on Form 8-K during the quarter covered by this report all information required to be reported on such form.

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

32.1 Certification of Periodic Financial Reports by B.A. Berilgen and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350

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SIGNATURE

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.

Date: August 14, 2006

/s/ Michael J. Rosinski

Michael J. Rosinski
Executive Vice President and Chief Financial Officer
(Duly authorized and Principal Financial Officer)

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ROSETTA RESOURCES INC.

INDEX OF EXHIBITS

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32.1	Certification of Periodic Financial Reports by B. A. Berilgen and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350