CITADEL BROADCASTING CORP
Form 10-Q
September 15, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2003

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 001-31740

CITADEL BROADCASTING CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**51-0405729** (IRS Employer Identification No.)
City Center West, Suite 400 **7201 West Lake Mead Blvd.** **Las Vegas, Nevada** (Address of principal executive offices)	**89128** (Zip code)

(702) 804-5200

(Registrant's telephone number, including area code)

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 o No ý

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý

As of September 1, 2003, there were 122,911,490 shares of common stock, $.01 par value per share, outstanding.

CITADEL BROADCASTING CORPORATION

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FORWARD-LOOKING INFORMATION

Certain matters in this Form 10-Q, including, without limitation, certain matters discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Quantitative and Qualitative Disclosures about Market Risk, constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are typically identified by the words "believes," "expects," "anticipates," and similar expressions. In addition, any statements that refer to expectations or other characterizations of future events or circumstances are forward-looking statements. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and that matters referred to in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements of Citadel Broadcasting Corporation to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among other things, the impact of current or pending legislation and regulation, antitrust considerations and other risks and uncertainties, as well as those matters discussed in Exhibit 20.1 titled "Risks Related to Our Business" to Citadel Broadcasting Corporation's Current Report on Form 8-K filed on August 11, 2003. Citadel Broadcasting Corporation undertakes no obligation to publicly update or revise these forward-looking statements because of new information, future events or otherwise.

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS (unaudited)

CITADEL BROADCASTING CORPORATION AND SUBSIDIARIES
Consolidated Condensed Balance Sheets
(in thousands, except share and per share data)
(unaudited)

	June 30, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,775	$ 2,134
Accounts receivable, less allowance for doubtful accounts of $4,190 and $4,321, respectively	68,267	66,473
Prepaid expenses and other current assets (including deferred income tax assets of $4,470 and $4,589, respectively)	9,541	8,498
Total current assets	82,583	77,105
Property and equipment, net	101,092	103,611
FCC licenses	1,223,029	1,187,457
Goodwill	597,908	596,287
Other intangibles, net	144,157	203,736
Other assets, net	29,063	30,137
Total assets	$ 2,177,832	$ 2,198,333
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 28,830	$ 27,806
Current maturities of notes payable and other long-term obligations	19,512	20,216
Total current liabilities	48,342	48,022
Notes payable	515,923	501,250
Subordinated debt	500,000	500,000
Other long-term obligations, less current maturities	10,808	12,013
Deferred income tax liabilities	284,159	270,473
Total liabilities	1,359,232	1,331,758
Commitments and contingencies		
Shareholders' equity:		
Preferred stock, $.01 par value authorized, 200,000,000 shares at June 30, 2003 and December 31, 2002; no shares issued or outstanding at June 30, 2003 and December 31, 2002		
Class A common stock, $.01 par value authorized, 487,500,000 shares at June 30, 2003 and December 31, 2002; issued and outstanding, 96,134,329 shares at June 30, 2003 and December 31, 2002	961	961
Class B common stock, $.01 par value authorized, 12,500,000 shares at June 30, 2003 and December 31, 2002; issued and outstanding, 3,365,948 and 3,957,228 shares at June 30, 2003 and December 31, 2002, respectively	34	40
Additional paid-in capital	1,024,731	1,026,625
Shareholder notes	(2,289)	(2,989)
Deferred compensation	(9,245)	(15,267)
Accumulated deficit	(195,592)	(142,795)
Total shareholders' equity	818,600	866,575
Total liabilities and shareholders' equity	$ 2,177,832	$ 2,198,333

See accompanying notes to consolidated condensed financial statements.

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CITADEL BROADCASTING CORPORATION AND SUBSIDIARIES
Consolidated Condensed Statements of Operations
(in thousands, except share and per share data)
(unaudited)

	Three Months Ended June 30, 2003	Three Months Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Gross broadcasting revenue	106,254	101,712	191,709	181,907
Less agency commissions	10,825	10,191	19,109	17,753
Net broadcasting revenue	95,429	91,521	172,600	164,154
Operating Expenses:				
Cost of revenues, exclusive of depreciation and amortization shown separately below	25,451	24,263	48,151	46,485
Selling, general and administrative	28,364	29,510	54,962	56,615
Corporate general and administrative	2,622	2,727	4,943	5,498
Corporate non-cash stock compensation	2,135	4,700	6,022	16,383
Depreciation and amortization	35,355	35,534	70,811	71,305
Operating expenses	93,927	96,734	184,889	196,286
Operating income (loss)	1,502	(5,213)	(12,289)	(32,132)
Non-operating expenses:				
Interest expense, net, including amortization of debt issuance costs of $916 and $913 for the three months ended June 30, 2003 and 2002, respectively, and $1,830 and $1,826 for the six months ended June 30, 2003 and 2002, respectively	13,673	15,525	27,659	31,114
Other, net	33	454	36	497
Non-operating expenses, net	13,706	15,979	27,695	31,611
Loss before income taxes	(12,204)	(21,192)	(39,984)	(63,743)
Income tax expense (benefit)	6,750	(2,898)	12,813	(8,783)
Net loss	(18,954)	(18,294)	(52,797)	(54,960)
Dividend requirement and premium paid on redemption of exchangeable preferred stock		1		3
Net loss applicable to common shares	(18,954)	(18,295)	(52,797)	(54,963)
Basic and diluted net loss per common share	$ (0.20)	$ (0.19)	$ (0.55)	$ (0.57)
Weighted average common shares outstanding	96,134,329	96,134,329	96,134,329	96,134,329

	Three Months Ended June 30,		Six Months Ended June 30,	

See accompanying notes to consolidated condensed financial statements.

CITADEL BROADCASTING CORPORATION AND SUBSIDIARIES
Consolidated Condensed Statements of Cash Flows
(in thousands)
(unaudited)

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Cash flows from operating activities:		
Net loss	$ (52,797)	$ (54,960)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	70,811	71,305
Amortization of debt issuance costs and debt discounts	1,830	1,826
Deferred income taxes	12,183	(9,438)
Stock compensation expense	6,022	16,383
Loss on sale of assets	56	291
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(1,773)	(3,685)
Prepaid expenses and other current assets	(1,210)	(388)
Accounts payable, accrued liabilities and other obligations	(3,823)	10,703
Net cash provided by operating activities	31,299	32,037
Cash flows from investing activities:		
Capital expenditures	(3,162)	(5,099)
Cash paid to acquire stations	(38,208)	
Proceeds from sale of assets	779	4,240
Other assets, net	(347)	(301)
Net cash used in investing activities	(40,938)	(1,160)
Cash flows from financing activities:		
Cash payments of public offering costs	(303)	(260)
Redemption of exchangeable preferred stock, including premiums		(1)
Net proceeds from notes payable	14,000	1,500
Principal payments on other long-term obligations	(230)	(492)
Principal and interest received on shareholder notes	766	1,250
Net repurchases of shares of Class B common stock	(1,900)	(11,349)
Payment of debt issuance costs	(53)	
Net cash provided by (used in) financing activities	12,280	(9,352)

	Six Months Ended June 30,	
Net increase in cash and cash equivalents	2,641	21,525
Cash and cash equivalents, beginning of period	2,134	666
Cash and cash equivalents, end of period	$ 4,775	$ 22,191

Supplemental schedule of investing activities:

The Company completed various radio station acquisitions during the six-month period ended June 30, 2003. In connection with these acquisitions, certain liabilities were assumed.

Fair value of assets acquired	43,233
Cash paid to acquire stations	(38,208)
Liabilities assumed	5,025

CITADEL BROADCASTING CORPORATION AND SUBSIDIARIES
Consolidated Condensed Statements of Cash Flows (Continued)
(in thousands)
(unaudited)

Supplemental Schedule of Cash Flow Information:

	Six Months Ended June 30,	
	2003	**2002**
Cash Payments:		
Interest	28,431	17,389
Income taxes	540	441
Barter Transactions:		
Equipment purchases through barter	88	174
Barter Revenue included in gross broadcasting revenue	3,468	4,676
Barter Expenses included in cost of revenues	3,390	4,700

See accompanying notes to consolidated condensed financial statements.

CITADEL BROADCASTING CORPORATION AND SUBSIDIARIES
Notes to Consolidated Condensed Financial Statements
(unaudited)

1. BASIS OF PRESENTATION

In January 2001, Citadel Broadcasting Corporation, (formerly FLCC Holdings, Inc.), through its wholly owned subsidiary, FLCC Acquisition Corp. ("Acquisition Corp."), corporations formed by affiliates of Forstmann Little & Co. ("FL&Co."), entered into an agreement with Citadel Communications Corporation ("Citadel Communications") to acquire substantially all of the outstanding common stock of Citadel Communications for cash and a portion in exchange for equity securities of Citadel Broadcasting Corporation (the "Acquisition") in a leveraged buyout transaction. The Acquisition was effected by the tender offer related to the exchangeable preferred stock and notes of Citadel Broadcasting Company, a wholly owned subsidiary of Citadel Communications ("Citadel Broadcasting" and together with Citadel Communications, prior to the Acquisition, the "Predecessor Company"), which was completed on June 26, 2001, followed by the merger of Acquisition Corp. into Citadel Communications, with Citadel Communications being the surviving company. Following the merger, Citadel Communications became a wholly owned subsidiary of Citadel Broadcasting Corporation.

Citadel Broadcasting Corporation was incorporated in Delaware in 1993 but did not have any business or assets until it was capitalized by partnerships affiliated with FL&Co. in connection with the Acquisition. Citadel Communications owns all of the issued and outstanding common stock of Citadel Broadcasting. Citadel Broadcasting owns and operates radio stations and holds Federal Communications Commission ("FCC") licenses in twenty-five states and has entered into a local marketing agreement for the stations it owns in Tyler, Texas. Radio stations serving the same geographic area (i.e., principally a city or combination of cities) are referred to as a market, and multiple markets aggregated geographically within the United States are referred to as a region. The Company aggregates the markets in which it operates into one reportable segment as defined by Statement of Financial Accounting Standards ("SFAS") No. 131, *Disclosures about Segments of an Enterprise and Related Information*.

The accompanying unaudited consolidated condensed financial statements of Citadel Broadcasting Corporation and Subsidiaries (the "Company") have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America for complete financial statements. In the opinion of management, all adjustments necessary for a fair presentation of results of the interim periods have been made, and such adjustments were of a normal and recurring nature. Operating results for the six months ended June 30, 2003 are not necessarily indicative of the results that may be expected for the year ending December 31, 2003. For further information, refer to the consolidated financial statements and notes thereto included in Citadel Broadcasting Corporation's Registration Statement on Form S-1, which became effective on July 31, 2003.

Certain prior year amounts have been reclassified to conform to the current year's presentation.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities, revenue and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

Recent Accounting Pronouncements

In April 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* The most significant provisions of SFAS No. 145 relate to the rescission of SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt*, but SFAS No. 145 also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. Under this new statement, any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet certain defined criteria must be reclassified. Generally, SFAS No. 145 is effective for our 2003 fiscal year, with early application encouraged. The Company adopted this statement on January 1, 2003.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring*). SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. A fundamental conclusion reached by the FASB in this statement is that an entity's commitment to a plan, by itself, does not create a present obligation to others that meets the definition of a liability. This statement also establishes that fair value is the objective for initial measurement of the liability. Adoption of SFAS No. 146 by the Company was effective on January 1, 2003 and was not retroactive to prior years. The adoption of SFAS No. 146 did not have a material impact on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation ("*FIN*") No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. Additionally, a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial liability recognition and measurement provisions of FIN No. 45 apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure requirements in FIN No. 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. The adoption of FIN No. 45 on January 1, 2003 did not have a material impact on the Company's financial position or results of operations.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure and amendment of FASB Statement No. 123*. SFAS No. 148 amends SFAS No. 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition to SFAS No. 123's fair value method of accounting for stock-based employee compensation. SFAS No. 148 also amends the disclosure provisions of SFAS No. 123 and Accounting Principles Board ("APB") Opinion No. 28, *Interim Financial Reporting*, to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. While SFAS No. 148 does not amend SFAS No. 123 to require companies to account for employee stock options using the fair value method, the disclosure provisions of SFAS No. 148 are applicable to companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method of SFAS No. 123 or the intrinsic value method of APB Opinion No. 25. SFAS No. 148's amendment of the transition and annual disclosure requirements of SFAS No. 123 are effective for the fiscal years ending after December 15, 2002. SFAS No. 148's amendment of the disclosure requirements of APB Opinion No. 28 is effective for financial reports containing financial statements for interim periods beginning after December 15, 2002.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51, Consolidated Financial Statements*. This interpretation applies immediately to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003 to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. This interpretation may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. The adoption of FIN No. 46 is not expected to have a material impact on the Company's financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment to Statement 133 on Derivative Instruments and Hedging Activities*. SFAS No. 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is applied prospectively and is effective for contracts entered into or modified after June 30, 2003, except for SFAS No. 133 implementation issues that have been effective for fiscal quarters that began prior to June 15, 2003 and certain provisions relating to forward purchases and sales of securities that do not yet exist. The Company believes that the adoption of SFAS No. 149 will not have a material impact on the Company's financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company will adopt the standard on July 1, 2003. The Company has not determined the effect, if any, that SFAS No. 150 will have on its consolidated financial statements.

2. STOCK-BASED COMPENSATION

The Company accounts for stock-based compensation in accordance with the requirements of APB Opinion No. 25 *Accounting for Stock Issued to Employees,* and related interpretations. SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure,* requires disclosure of the pro forma effects on net income and earnings per share as if the Company had adopted the fair value recognition provisions of SFAS No. 123. Had compensation cost for the Company's stock-based awards to employees been based on the fair value at the grant dates in accordance with the fair value provisions of SFAS No. 123, the

Company's net loss and net loss per share for the three-month and six-month periods ended June 30, 2003 and 2002 would have been changed to the pro forma amounts indicated below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(Amounts in thousands, except per share amounts)			
Net loss applicable to common shares, as reported	$ (18,954)	$ (18,295)	$ (52,797)	$ (54,963)
Add: Corporate non-cash stock compensation expense	2,135	4,700	6,022	16,383
Deduct: Total stock-based employee compensation expense determined under fair value method	(2,850)	(5,076)	(7,946)	(17,692)
Net loss applicable to common shares, pro forma	$ (19,669)	$ (18,671)	$ (54,721)	$ (56,272)
Net loss per common share:				
As reported	$ (0.20)	$ (0.19)	$ (0.55)	$ (0.57)
Pro forma	$ (0.20)	$ (0.19)	$ (0.57)	$ (0.59)

For those awards that result in the recognition of compensation expense under APB Opinion No. 25, the Company records expense for each tranche of the award over the vesting period applicable to such tranche, which results in the accelerated recognition of compensation expense.

3. INTANGIBLE ASSETS AND GOODWILL

Indefinite-Lived Intangibles and Goodwill

In June 2001, the FASB issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. The Company adopted SFAS No. 141 for all business combinations completed after June 30, 2001, which requires that such business combinations be accounted for under the purchase method. The Company adopted SFAS No. 142 at the beginning of 2002 for all goodwill and other intangible assets recognized in the Company's balance sheet as of January 1, 2002. This standard changes the accounting for goodwill and intangible assets with indefinite lives from an amortization method to an impairment-only approach and introduces a new model for determining impairment charges. Amortization of goodwill and indefinite-lived intangibles ceased upon adoption of SFAS No. 142.

The new impairment model for goodwill under SFAS No. 142 requires performance of a two-step test for operations that have goodwill assigned to them. First, it requires a comparison of the book value of the net assets of each reporting unit to the fair value of the related operations. If fair value is determined to be less than book value, a second step is performed to compute the amount of impairment. In this process, the fair value of goodwill is estimated and is compared to its book value. Any shortfall of the fair value below book value represents the amount of goodwill impairment.

In the first quarter of 2002, the Company completed its transitional assessment of goodwill and other identifiable intangibles in accordance with the standard's guidance. The Company believes that FCC licenses are indefinite-lived intangibles under the new standard. The Company compares the fair value of these intangibles to their net book value and if the net book value exceeds fair value, the Company will record an impairment charge to its statement of operations. The transitional assessment performed by the Company did not identify any impairment as the fair value of its reporting units exceeded their net book value.

The Company's assessment for impairment of goodwill is performed at the radio market level, which the Company determined to be its reporting units. The Company's assessment of its indefinite-lived intangibles, other than goodwill, which consists primarily of FCC licenses, is also performed at the radio market level.

The fair value of each of the Company's FCC licenses was directly valued based upon a hypothetical start-up station with identical facilities and FCC licenses to the Company's stations and was not based on a residual approach. The calculation also incorporated the number of stations in the market and the total market radio revenue and an assumed operating margin. As part of the Company's transitional assessment of identifiable intangibles in connection with the adoption of SFAS No. 142, which was completed in the first quarter 2002, the Company determined that there were no significant changes that would have negatively impacted the value of the FCC licenses or the factors considered in determining the value of the FCC licenses. Therefore, the Company determined that no impairment existed as of the date of the transitional assessment. In addition, the Company also determined that there were no significant changes that would have impacted the valuation of the FCC licenses during 2002 and therefore no impairment existed at the Company's 2002 annual assessment date, October 1.

The impairment testing for the Company's goodwill upon adoption of SFAS No. 142 and for 2002, as of October 1, its annual assessment date, was determined based primarily on discounted expected future cash flows to be generated from each market. These cash flows were then compared to the net book value of all intangible and tangible assets of each market, including goodwill. In each case, the net book value of all the assets, including goodwill, did not exceed the discounted cash flow of each market, indicating that there was no impairment of goodwill at the transitional assessment or as of its 2002 annual assessment.

The changes in the carrying amounts of FCC licenses and goodwill for the period from December 31, 2002 through June 30, 2003 are as follows:

	FCC Licenses	Goodwill
	(in thousands)	
Balance, December 31, 2002	$ 1,187,457	$ 596,287
Station acquisitions	35,750	1,621
Station disposition	(178)	
Balance, June 30, 2003	$ 1,223,029	$ 597,908

Definite-Lived Intangibles

The Company has definite-lived intangible assets that consists primarily of advertiser base, which are amortized in accordance with SFAS No. 142. The amount of the amortization expense for definite-lived intangible assets was $61.2 million and $62.8 million for the six months ended June 30, 2003 and 2002, respectively, and $30.5 million and $31.4 million for the three months ended June 30, 2003 and 2002, respectively. As of June 30, 2003, Other Intangibles, Net on the accompanying consolidated condensed balance sheet reflects $144.2 million in unamortized definite-lived assets.

The following table presents the Company's estimate of amortization expense for each of the five succeeding years ending December 31, for definite-lived assets (in thousands):

	Amortization Expense
	(in thousands)
2003 (includes the six months ended June 30, 2003)	$ 119,221
2004	69,256
2005	11,964
2006	2,876
2007	
	$ 203,317

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As acquisitions and dispositions occur in the future and as purchase price allocations are finalized, amortization expense may vary from the amounts detailed above.

4. ACQUISITIONS AND DISPOSITIONS

Pending Acquisitions and Dispositions

As of June 30, 2003, the Company has various agreements to acquire 15 radio stations for a combined aggregate purchase price of approximately $158.1 million. Below is a summary of the significant acquisitions and expected periods in which the acquisitions should close:

Five radio stations in the Des Moines, IA market, four radio stations in the New Orleans, LA market, and two radio stations in the Springfield, MO market for an aggregate cash purchase price of $133.0 million. The Company expects this acquisition to be completed in the third quarter of 2003.

Two radio stations in the Providence, RI market for an aggregate cash purchase price of $14.5 million. The Company expects this acquisition to close in the fourth quarter of 2003.

One radio station in the Lafayette, LA market for an aggregate cash purchase price of $7.7 million. The Company expects this acquisition to close in the fourth quarter of 2003.

The Company will operate the stations in Providence pending the acquisitions, under a local marketing agreement. The Company will also sell advertising on the station in Lafayette under a joint sales agreement.

Additionally, on November 5, 2002, the Company entered into an agreement in the form of an option, exercisable through December 31, 2006, to purchase a radio station in the Oklahoma City, OK market for an aggregate cash purchase price of (i) on or before December 31, 2004, $15.0 million or (ii) after December 31, 2004, the greater of $15.0 million or 85% of the fair market value of the radio station, as determined by an independent appraisal. Under the local marketing agreement, the Company will operate the station during the option period.

As of June 30, 2003, the Company has pending agreements to sell one radio station in Reno, NV for approximately $4.3 million in cash and five stations in Tyler/Longview, TX for an aggregate purchase price of $6.0 million, of which $5.5 million will be in the form of a note. The Company has four additional pending asset purchase agreements to sell an aggregate of six stations in four markets for aggregate cash purchase prices totaling $1.8 million.

Completed Acquisitions

During the six months ended June 30, 2003, the Company completed five acquisitions for a total of eight radio stations with a combined aggregate purchase price of approximately $38.2 million.

All of the Company's acquisitions have been accounted for by the purchase method of accounting. As such, the accompanying consolidated condensed balance sheets include the acquired assets and liabilities and the accompanying consolidated condensed statements of operations include the results of operations of the acquired entities from their respective dates of acquisition.

For the completed acquisitions, the combined aggregate purchase price was allocated as follows and is based upon information available at this time and is subject to change upon the finalization of the valuation of acquired assets and liabilities:

Asset Description	Amount (in thousands)	Asset lives
Property and equipment, net	$ 4,421	3-25 years
FCC licenses	35,750	non-amortizing
Goodwill	1,621	non-amortizing
Other intangibles, net	1,441	3 years
Liabilities assumed	(5,025)	
Total aggregate purchase price	$ 38,208	

Asset Description	Amount	Asset lives

5. NOTES PAYABLE

Effective January 31, 2003, the Company's Credit Agreement was amended, decreasing the Term B loans from $250.0 million to $200.0 million and decreasing the applicable margins on the Term B loans from a range between 2.75% and 3.25% for Eurodollar borrowings to 2.50%. The repayment of the Term B Loan was financed through borrowings under the Revolving Loan Facility.

On March 31, 2003, the Company repaid $34.0 million on the Term A and B loans with borrowings under the revolving loans. Payments made on the Term A and B loans reduce the commitment under the Credit Agreement and therefore the funds are not available for future borrowings. For the Term A loans, the prepayment of $18.9 million was applied to the September 2003 and December 2003 quarterly payments of $9.4 million each due under the Credit Agreement, and the remaining $0.1 million was applied to the March 2004 payment. For the Term B loans, the prepayment of $15.1 million was applied to the September 2003, December 2003, and March 2004 quarterly payments of $0.5 million each due under the Credit Agreement, and the remaining $13.6 million reduced the required future quarterly payments on a pro-rata basis.

Below is a table that sets forth the rates and the amounts borrowed under the Credit Agreement as of December 31, 2002 and June 30, 2003:

Type of Borrowing	December 31, 2002 Amount of Borrowing (in thousands)	December 31, 2002 Interest Rate	June 30, 2003 Amount of Borrowing (in thousands)	June 30, 2003 Interest Rate
Term A	$ 250,000	3.93%	$ 231,111	3.55%
Term B	250,000	4.54%	184,889	3.79%
Revolving Loan	17,500	3.88%	94,000	3.36%
Revolving Loan	3,500	5.75%	3,000	3.54%
Revolving Loan			22,000	3.57%

The required aggregate principal payments for the Term A and B loans for each of the succeeding twelve month periods and thereafter as of June 30, 2003 are as follows:

	Term A	Term B	Total
		(in thousands)	
2004	$ 18,611	$ 466	$ 19,077
2005	50,000	1,863	51,863
2006	50,000	1,863	51,863
2007	50,000	1,863	51,863
2008	62,500	1,863	64,363
Thereafter		176,971	176,971
	$ 231,111	$ 184,889	$ 416,000

As of June 30, 2003, the Company has outstanding borrowings under the revolving loans of $119.0 million. In addition, the Company has $9.1 million in letters of credit outstanding primarily related to pending acquisitions. Net of outstanding borrowings and letters of credit, the Company has $71.9 million available for future borrowings under the revolving loans as of June 30, 2003.

At December 31, 2002 and June 30, 2003, the Company was in compliance with all covenant provisions.

6. SUBORDINATED DEBT

On June 26, 2001, the Company completed the issuance of $500.0 million of 6% Subordinated Debentures ("6% Debentures") to two partnerships affiliated with FL&Co. The 6% Debentures are subordinate and junior in right of payment to the Notes Payable discussed in Note 5. Interest is payable semi-annually on the 30th day of June and the 31st day of December in each year, computed on the basis of a 360-day year of twelve 30-day months at an annual rate of 6%. Principal payments under these debentures of approximately $166.7 million are due on June 26, 2012, 2013 and 2014.

7. SHAREHOLDERS' EQUITY

On May 12, 2003, the Company repurchased 457,120 shares of Class B common stock held by its former Chief Financial Officer at cost in accordance with the shareholder's agreement for an aggregate purchase price of $1.6 million. On June 11, 2003, the Company repurchased 228,560 shares of Class B common stock held by a former officer of the Company at cost in accordance with the shareholder's agreement for an aggregate purchase price of $0.8 million.

On May 21, 2003, the Company's new Chief Operating Officer purchased 94,400 shares of Class B common stock of the Company for an aggregate purchase price of $0.5 million. These shares of Class B common stock are subject to a stockholder's agreement, which, among other things, restricts the transfer of the shares of Class B common stock.

8. INCOME TAXES

Income tax expense for 2003 was primarily due to the amortization of indefinite-lived intangibles for income tax purposes, for which no benefit can be recognized in the financial statements until the assets are disposed of. The income tax benefit for 2002 was primarily due to benefits related to the Company's net operating losses offset by increases in the valuation allowance.

9. NET LOSS PER SHARE

Basic net loss per share is computed by dividing loss available to common shareholders by the weighted-average number of Class A common shares outstanding for the period. Diluted net loss per

share reflects the potential dilution that could occur if securities or contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the losses of the Company. The Company had options to issue 4,150,000 and 5,957,750 shares of Class A common stock outstanding as of June 30, 2002 and June 30, 2003, respectively. However, these options and outstanding shares of Class B common stock have been excluded from the calculations of diluted net loss per share as their effect is antidilutive.

10. COMMITMENTS AND CONTINGENCIES

In October 1999, the Radio Music License Committee (RMLC), of which the Company is a participant, filed a motion in the New York courts against Broadcast Music, Inc. (BMI) to commence a rate-making proceeding on behalf of the radio industry and to seek a determination of fair and reasonable industry-wide license fees for the broadcast of music. In July 2003, the RMLC entered into an agreement on behalf of the radio industry with BMI. This agreement, which is subject to approval by the United States District Court in New York, replaces the interim agreement under which the Company had been operating since January 1, 1997. The Company's management estimates that the impact of this agreement will not materially affect the financial position or results of operations of the Company.

In a complaint filed on June 5, 2003, with the United States District Court for the District of Connecticut, the Company was named as one of numerous defendants in litigation seeking monetary damages arising from the injuries and deaths of certain concertgoers at a Rhode Island nightclub. The complaint contains multiple causes of action, only a small number of which are brought against the Company, in which the Company's sole involvement was to advertise the concert on one of its stations and to distribute promotional tickets provided by the organizers. The complaint alleges, among other things, that the organizers and sponsors of the concert failed to control crowd size, failed to obtain pyrotechnic permits, failed to inspect fireproofing at the club and failed to maintain emergency exits in workable condition, which contributed to the injuries and deaths of plaintiffs when pyrotechnic devices on the stage ignited soundproofing materials adjacent to the stage during the concert. The complaint alleges that the Company was a co-sponsor of the concert and asserts claims against the Company based on theories of joint venture liability and negligence. The Company believes that plaintiffs' claims against the Company are without merit and the Company intends to defend these claims vigorously.

The Company is subject to other claims and lawsuits arising in the ordinary course of its business. The Company believes that none of these legal proceedings, individually or in the aggregate, would have a material adverse impact on its results of operations, cash flows or financial condition.

11. SUBSEQUENT EVENTS

The Company's initial public offering registration statement with the Securities and Exchange Commission was declared effective on July 31, 2003, and the Company issued 25.3 million shares (which includes the over allotment exercised by the underwriters of 3.3 million shares) of its common stock at $19.00 per share for an aggregate gross sales price of $480.7 million. The proceeds from the sale of the stock net of underwriting commissions of approximately $28.8 million were paid to the Company on August 6, 2003. In connection with this initial public offering, the Company completed a recapitalization immediately prior to, or simultaneously with, the closing as follows:

each outstanding share of Class B common stock was exchanged for .518 shares of Class A common stock;

the Class A common stock was redesignated as common stock; and

the certificate of incorporation was amended and restated to reflect a single class of common stock, par value $.01 per share.

After the recapitalization described above, the Company had 122,911,490 shares of common stock outstanding.

The Company used substantially all of the net proceeds to first repay amounts outstanding under the Term B loan, then to repay amounts outstanding under the revolving portion of the credit facility, with the remaining proceeds used to repay amounts outstanding under the Term A loan. After the application of the proceeds, the Company had approximately $78.1 million outstanding under the Term A loan.

On August 8, 2003, the Company entered into an asset purchase agreement to sell one radio station in the Harrisburg, PA market and three radio stations in the Wilkes-Barre, PA market for an aggregate cash purchase price of $2.5 million and on August 29, 2003 the Company entered into an asset purchase agreement to sell two radio stations in the Springfield, MO market for an aggregate purchase price of $5.1 million. In addition, the purchaser of the Springfield, MO stations will operate the stations under a local marketing agreement effective September 8, 2003.

On September 8, 2003, the Company completed the acquisition of five radio stations in the Des Moines, IA market, four radio stations in the New Orleans, LA market, and two radio stations in the Springfield, MO market for an aggregate cash purchase price of $133.0 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

Certain matters in this Form 10-Q, including, without limitation, certain matters discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations and in Quantitative and Qualitative Disclosures about Market Risk, constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Those statements include statements regarding the intent, belief or current expectations of Citadel Broadcasting Corporation and its subsidiaries (collectively the "Company"), its directors or its officers with respect to, among other things, future events and financial trends affecting the Company.

Forward-looking statements are typically identified by the words "believes," "expects," "anticipates," and similar expressions. In addition, any statements that refer to expectations or other characterizations of future events or circumstances are forward-looking statements. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and that matters referred to in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among other things, the impact of current or pending legislation and regulation, antitrust considerations and other risks and uncertainties, as well as those matters discussed in Exhibit 20.1 titled "Risks Related to Our Business" to Citadel Broadcasting Corporation's Current Report on Form 8-K filed on August 11, 2003. The Company undertakes no obligation to publicly update or revise these forward-looking statements because of new information, future events or otherwise.

Introduction

Citadel Broadcasting Company, which together with its parent Citadel Communications Corporation, we refer to as our predecessor company, was founded in 1991 and grew rapidly through acquisitions subsequent to the passage of the Telecommunications Act of 1996. In June 2001, affiliates of Forstmann Little & Co. acquired our predecessor company from its public shareholders for an aggregate purchase price, including the redemption of debt and exchangeable preferred stock, of approximately $2.0 billion.

Our operating subsidiary, Citadel Broadcasting Company, owns and operates radio stations and holds Federal Communications Commission (FCC) licenses in twenty-five states.

Sources of Revenue

Our net broadcasting revenue is primarily derived from the sale of broadcasting time to local, regional and national advertisers. Net broadcasting revenue is gross revenue less agency commissions. Local revenue is comprised of advertising sales made within a station's local market or region either directly with the advertiser or through the advertiser's agency. National revenue represents sales made to advertisers/agencies who are purchasing advertising for multiple markets. These sales are typically facilitated by our national representation firm, which serves as our sales agent in these transactions. Our revenue is affected primarily by the advertising rates our radio stations charge as well as the overall demand for radio advertising time in a market. Advertising rates are based primarily on four factors:

- a radio station's audience share in the demographic groups targeted by advertisers, as measured principally by quarterly reports issued by The Arbitron Ratings Company, or Arbitron;

- the number of radio stations, as well as other forms of media, in the market competing for the same demographic groups;
- the supply of and demand for radio advertising time; and
- the size of the market.

In the radio broadcasting industry, seasonal revenue fluctuations are common and are due primarily to variations in advertising expenditures by local and national advertisers. Typically, revenue is lowest in the first calendar quarter of the year and highest in the second and fourth calendar quarters of the year.

Components of Expenses

Our most significant expenses are (1) sales costs, (2) programming expenses, (3) advertising and promotional expenses and (4) administrative and technical expenses. We strive to control these expenses by working closely with local management and centralizing functions such as finance, accounting, legal, human resources and management information systems. We also use our multiple stations, market presence and purchasing power to negotiate favorable rates with vendors.

Depreciation and amortization of costs associated with the acquisition of radio stations and interest carrying charges historically have been significant factors in determining our overall profitability. Based on intangible assets currently held by us, and not giving effect to the closing of pending radio station acquisitions, we expect the total amortization expense incurred will continue to decrease due to the remaining weighted-average useful amortization period of intangible assets subject to amortization.

Results of Operations

Our results of operations represent the operations of the radio stations owned or operated by us, or for which we provide sales and marketing services, during the applicable periods. The following discussion should be read in conjunction with the accompanying consolidated condensed financial statements and the related notes included in this report.

Historically, we have managed our portfolio of radio stations through selected acquisitions, dispositions and exchanges, as well as through the use of local marketing agreements, or LMAs, and joint sales agreements, or JSAs. Under an LMA or a JSA, the company operating a station provides programming or sales and marketing or a combination of such services on behalf of the owner of a station. The broadcast revenue and operating expenses of stations operated by us under LMAs and JSAs have been included in our results of operations since the respective effective dates of such agreements.

Three Months Ended June 30, 2003 Compared to Three Months Ended June 30, 2002

Net Broadcasting Revenue. Net broadcasting revenues in the second quarter of 2003 were $95.4 million compared with $91.5 million in the second quarter of 2002, an increase of $3.9 million, or 4.3%. The increase was caused by higher revenues from most of our stations. National revenue increased approximately $0.9 million, or 5.9%, while local revenue increased approximately $3.0 million, or 4.0%. Net broadcasting revenue, excluding barter revenue, increased in the three months ended June 30, 2003 by $4.7 million, or 5.3%, compared to the corresponding period in 2002, while barter revenue, which represents revenue earned in exchange for goods or services received from advertisers, decreased $0.8 million, or 29.5%.

Operating Expenses. Operating expenses decreased $2.8 million, or 2.9%, to $93.9 million for the three months ended June 30, 2003 from $96.7 million for the three months ended June 30, 2002. This was primarily due to a decrease in corporate non-cash stock compensation of $2.6 million from $4.7 million during the three months ended June 30, 2002. The compensation expense relates to stock options granted to and shares of common stock issued to our chief executive officer in 2002, and the

expense is recognized over the vesting period of the options and shares. Depreciation and amortization expense of $35.4 million for the quarter ended June 30, 2003 was relatively unchanged compared to the June 30, 2002 quarter. Amortization expense for the quarter ended June 30, 2003 and 2002 included approximately $28.8 million of expense related to the Company's Advertiser Base asset, established upon the initial acquisition of Citadel Communications Corporation in June 2001. The amortization for the Advertiser Base will decline significantly in 2004 and 2005. The Advertiser Base amortization expense for each of the three years ending December 31 is estimated as follows: $113 million (2003), $66 million (2004) and $10 million (2005), respectively.

Operating Income. Operating income for the second quarter 2003 was $1.5 million compared with an operating loss of $5.2 million in the corresponding 2002 period, resulting in an overall improvement of $6.7 million. The increase in operating income for the second quarter 2003 was primarily due to higher net broadcasting revenue combined with flat operating expenses and a decrease in corporate non-cash stock compensation.

Interest Expense, Net. Net interest expense decreased $1.8 million to $13.7 million for the quarter ended June 30, 2003 from $15.5 million for the quarter ended June 30, 2002, a decrease of 11.6%. Net interest expense in both periods included amortization of deferred financing costs of approximately $0.9 million. This decrease in net interest expense was primarily due to a reduction in outstanding borrowings and lower interest rates for the quarter ended June 30, 2003 compared to the same period in 2002.

Income Tax Expense. Income tax expense for the quarter ended June 30, 2003 was $6.8 million compared with an income tax benefit of $2.9 million for the quarter ended June 30, 2002. The income tax expense for the quarter ended June 30, 2003 was primarily due to the amortization of indefinite-lived intangibles for income tax purposes, for which no benefit can be recognized in the financial statements until the assets are disposed of. The income tax benefit for the quarter ended June 30, 2002 was primarily due to benefits related to our net operating losses offset by increases in the valuation allowance. The income tax expense/(benefit) includes current income tax expense of approximately $0.3 million and $0.2 million for the three months ended June 30, 2003 and 2002, respectively.

Net Loss. Net loss for the quarter ended June 30, 2003 was $19.0 million, or $0.20 per basic and diluted share, as compared to a net loss of $18.3 million, or $0.19 per basic and diluted share, for the same period in 2002. The net loss for both periods was significantly impacted by depreciation and amortization expense and non-cash stock compensation expense of $35.4 million and $2.1 million, respectively, for the three months ended June 30, 2003, and $35.5 million and $4.7 million, respectively, for the three months ended June 30, 2002.

Net Loss Per Share. The loss per share amounts were computed based on the shares outstanding prior to the Company's initial public offering. In August of 2003, the Company completed its initial public offering and issued 25.3 million shares (including an over allotment of 3.3 million shares) of common stock at $19.00 per share.

Six Months Ended June 30, 2003 Compared to Six Months Ended June 30, 2002

Net Broadcasting Revenue. Net broadcasting revenues for the six months ended June 30, 2003 were $172.6 million compared with $164.2 million for the six months ended June 30, 2002, an increase of $8.4 million, or 5.1%. The increase was caused by higher revenues from most of our stations. National revenue increased approximately $2.7 million, or 10.8%, while local revenue increased approximately $5.7 million, or 4.1%. Net broadcasting revenue, excluding barter revenue, increased in the six months ended June 30, 2003 by $9.7 million, or

6.1%, compared to the corresponding period in 2002, while barter revenue, which represents revenue earned in exchange for goods or services received from advertisers, decreased $1.2 million, or 25.8%.

Operating Expenses. Operating expenses decreased $11.4 million, or 5.8%, to $184.9 million for the six months ended June 30, 2003 from $196.3 million for the six months ended June 30, 2002. This was primarily due to corporate non-cash stock compensation, which decreased by $10.4 million, or 63.4%, from $16.4 million during the six months ended June 30, 2002 to $6.0 million during the six months ended June 30, 2003. The compensation expense relates to stock options granted and shares of common stock issued to our chief executive officer in 2002, and the expense is recognized over the vesting period of the options and shares. Depreciation and amortization expense of $70.8 million for the six months ended June 30, 2003 was relatively unchanged compared to the June 30, 2002 period. Amortization expense for the six months ended June 30, 2003 and 2002 included approximately $57.7 million of expense related to the Company's Advertiser Base asset, established upon the initial acquisition of Citadel Communications Corporation in June 2001. The amortization for the Advertiser Base will decline significantly in 2004 and 2005. The Advertiser Base amortization expense for each of the three years ending December 31 is estimated as follows: $113 million (2003), $66 million (2004) and $10 million (2005), respectively.

Operating Loss. Operating loss for the six months ended June 30, 2003 was $12.3 million compared with $32.1 million in the corresponding 2002 period, a decrease of $19.8 million, or 61.7%. The decrease in operating loss for the six months ended June 30, 2003 was primarily due to the increase in net broadcasting revenue combined with flat operating expenses and a decrease in corporate non-cash stock compensation.

Interest Expense, Net. Net interest expense decreased $3.4 million to $27.7 million during the six months ended June 30, 2003 from $31.1 million for the same period in June 30, 2002, a decrease of 10.9%. Net interest expense in both periods included amortization of deferred financing costs of approximately $1.8 million. This decrease in net interest expense was primarily due to a reduction in outstanding borrowings and lower interest rates for the six months ended June 30, 2003 compared to the same period in 2002.

Income Tax Expense. Income tax expense for the six months ended June 30, 2003 was $12.8 million compared to an income tax benefit of $8.8 million for the six months ended June 30, 2002. The income tax expense for the six months ended June 30, 2003 was primarily due to the amortization of indefinite-lived intangibles for income tax purposes, for which no benefit can be recognized in the financial statements until the assets are disposed of. The income tax benefit for the six months ended June 30, 2002 was primarily due to benefits related to our net operating losses offset by increases in the valuation allowance. The income tax expense/(benefit) includes current income tax expense of approximately $0.6 million and $0.7 million for the six months ended June 30, 2003 and 2002, respectively.

Net Loss. Net loss for the first six months of 2003 was $52.8 million, or $0.55 per basic and diluted share, as compared to a net loss of $55.0 million, or $0.57 per basic and diluted share, for the same period in 2002. The net loss for both periods was significantly impacted by depreciation and amortization expense and non-cash stock compensation of $70.8 million and $6.0 million, respectively, for the six months ended June 30, 2003, and $71.3 million and $16.4 million, respectively, for the six months ended June 30, 2002.

Net Loss Per Share. The loss per share amounts were computed based on the shares outstanding prior to the Company's initial public offering. In August of 2003, the Company completed its initial public offering and issued 25.3 million shares (including an over allotment of 3.3 million shares) of common stock at $19.00 per share.

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operations, undrawn commitments available under our credit facility and proceeds generated from the sale of our debt and equity securities. We have used, and will continue to use, a significant portion of our capital resources to complete acquisitions.

Initial Public Offering. Our initial public offering registration statement with the Securities and Exchange Commission was declared effective on July 31, 2003, and we issued 25.3 million shares (which includes the over allotment exercised by the underwriters of 3.3 million shares) of our common stock at $19.00 per share resulting in net proceeds to the Company of approximately $447.0 million after expenses. We used substantially all of our net proceeds from this offering to repay amounts outstanding under our credit facility. As of August 31, 2003, we had approximately $69.1 million outstanding under our credit facility. See "Credit Facility Initial Public Offering" for a further discussion of the impact on our credit facility.

Operating Activities. Net cash provided by operating activities of $31.3 million for the six months ended June 30, 2003 was relatively unchanged as compared to $32.0 million for the comparable six-month period in 2002.

Investing and Financing Activities. Net cash used in investing activities increased to $40.9 million for the six months ended June 30, 2003, as compared to $1.2 million for the six months ended June 30, 2002. During 2003, approximately $41.4 million was used for the acquisition of radio stations and capital expenditures, which includes buildings, studio equipment, towers and transmitters, vehicles and other assets utilized in the operation of our stations, compared to $5.1 million for similar costs in the 2002 period.

Net cash provided by financing activities was $12.3 million for the six months ended June 30, 2003, as compared to net cash used in financing activities of $9.4 million for the same period in 2002. For the six months ended June 30, 2003, the net cash provided by financing activities was primarily due to total net proceeds from notes payable of $14.0 million offset by approximately $1.9 million in net repurchases of our Class B common stock. For the six months ended June 30, 2002, the net cash used in financing activities was primarily due to total net proceeds from notes payable of $1.5 million offset by approximately $11.3 million in net repurchases of our Class B common stock.

During the six months ended June 30, 2003, we completed five acquisitions for a total of eight radio stations with a combined aggregate purchase price of approximately $43.2 million, and we funded these acquisitions through cash flows from operating activities and borrowings under our revolving credit facility.

Additionally, on September 8, 2003, we completed the acquisition of five radio stations in the Des Moines, IA market, four radio stations in the New Orleans, LA market, and two radio stations in the Springfield, MO market for an aggregate cash purchase price of $133.0 million. We funded this acquisition primarily through borrowings under our credit facility.

On May 12, 2003, we repurchased 457,120 shares of Class B common stock held by our former Chief Financial Officer for an aggregate purchase price of $1.6 million and on May 21, 2003, our new Chief Operating Officer purchased 94,400 shares of our Class B common stock for an aggregate purchase price of $0.5 million. Additionally, on June 11, 2003, we repurchased 228,560 shares of our Class B common stock held by a former officer for an aggregate purchase price of $0.8 million and on July 15, 2003, we repurchased 514,277 shares of our Class B common stock held by two former officers for an aggregate purchase price of approximately $1.8 million.

In addition to debt service, our principal liquidity requirements are for working capital and general corporate purposes, capital expenditures and acquisitions of additional radio stations. Our capital

expenditures totaled $3.2 million during the six months ended June 30, 2003, as compared to $5.1 million during the six months ended June 30, 2002. For the fiscal year ending December 31, 2003, we estimate that capital expenditures necessary for maintaining our facilities will be approximately $8.0 million. We believe that cash flows from operating activities, together with availability under our revolving credit facility, should be sufficient for us to fund our current operations for at least the next 12 months.

As of the date of this filing, we have three transactions pending to purchase radio stations for cash purchase prices aggregating $25.1 million and we intend to fund these acquisitions through borrowings under our credit facility, cash flows from operating activities, and from proceeds from our pending disposition of stations as described below.

The Company has pending agreements to sell one radio station in Reno, NV for approximately $4.3 million in cash and five stations in Tyler/Longview, TX for an aggregate purchase price of $6.0 million, of which $5.5 million will be in the form of a note. The Company has six additional pending asset purchase agreements to sell an aggregate of twelve stations in six markets for aggregate cash purchase prices totaling $9.4 million.

To the extent we require additional capital to fund our capital expenditures, pending or future acquisitions or any of our other contractual or commercial commitments, we intend to seek additional funding in the credit or capital markets and there can be no assurance that we will be able to obtain financing on terms acceptable to us.

Credit Facility

On June 26, 2001, we entered into a $700 million bank credit facility with a syndicate of banks and other financial institutions led by JPMorgan Chase Bank, as a lender and administrative agent. On January 29, 2003, we amended our credit facility which, in part, reduced the facility to $650 million by reducing the commitment on the tranche B term loan from $250 million to $200 million. We financed this $50 million reduction through borrowings under our revolving credit facility. On March 31, 2003, we repaid $34 million of term loans with borrowings under our revolving credit facility. Payments made on the term loans reduce the commitment under our credit facility and therefore the funds are not available for future borrowings. Our credit facility, as amended, consists of the following:

	Commitment	Balance Outstanding (as of June 30, 2003)
Tranche A term loan	$ 250,000,000	$ 231,111,111
Tranche B term loan	200,000,000	184,888,889
Revolving credit facility	200,000,000	119,000,000

Availability. The amount available under our credit facility at June 30, 2003 was approximately $81.0 million in the form of revolving credit commitments. This excludes approximately $9.1 million in letters of credit outstanding as of June 30, 2003. Our ability to borrow under our credit facility is limited by our ability to comply with several financial covenants as well as a requirement that we make various representations and warranties at the time of borrowing.

Initial Public Offering. Our initial public offering registration statement with the Securities and Exchange Commission was declared effective on July 31, 2003, and we issued 25.3 million shares (which includes the over allotment exercised by the underwriters of 3.3 million shares) of our common stock at $19.00 per share for an aggregate gross sales price of $480.7 million. The proceeds from the sale of the stock net of underwriting commissions of approximately $28.8 million were paid to the Company on August 6, 2003. We used substantially all of our net proceeds from this offering to repay amounts outstanding under our tranche B term loan and the revolving portion of our credit facility, with the remaining proceeds used to repay amounts outstanding under our tranche A term loan. After the application of the net proceeds, we had approximately $78.1 million outstanding under the tranche A

loan. The net proceeds used to repay amounts outstanding under our tranche A and tranche B term loans reduced the outstanding commitments under our credit facility and we will not be able to reborrow these amounts. The net proceeds used to repay amounts outstanding under our revolving credit facility will not reduce the outstanding commitment under the revolving portion of our credit facility. After giving effect to the repayment of the amounts outstanding under the revolving portion of our credit facility, we had $200 million available under our revolving credit facility, excluding approximately $9.1 million in outstanding letters of credit. On September 8, 2003, we borrowed $127 million under our revolving credit facility to complete the acquisition of the stations in Des Moines, IA, New Orleans, LA and Springfield, MO, discussed above. Our credit facility also provides that at any time prior to June 26, 2004, we may solicit incremental term and revolving loans not to exceed $400 million.

In connection with the full repayment of the tranche B term loan and the partial repayment of the tranche A term loan subsequent to June 30, 2003, we expect to write off related deferred financing costs. In addition, we are in discussions with our lenders in anticipation of amending our credit facility. In the third quarter of 2003, we expect to write off a significant portion of deferred financing costs related to our credit facility, which had a net balance of approximately $13.4 million at June 30, 2003. If all of the deferred financing costs related to our credit facility are written-off, the related amortization expense included in interest expense would decline by approximately $2.5 million annually, exclusive of any new deferred financing costs associated with amending the credit facility.

Maturity and Amortization. The term loans are repayable in quarterly installments pursuant to a predetermined payment schedule. After the application of the net proceeds from the initial public offering, the tranche A term loan is repayable over a period of five years in quarterly installments, beginning on September 30, 2004, in amounts ranging from $4.6 million and increasing to $5.7 million for the final four quarterly repayments. The final quarterly payment on the tranche A term loan is due June 26, 2008. As discussed above, the tranche B term loan was repaid on August 6, 2003.

Non-Financial Covenants. Our credit facility contains customary restrictive non-financial covenants, that, among other things, and with certain exceptions, limit our ability to incur additional indebtedness, liens and contingent obligations, enter into transactions with affiliates, make acquisitions, declare or pay dividends, redeem or repurchase capital stock, enter into sale and leaseback transactions, consolidate, merge or effect asset sales, make capital expenditures, make investments, loans, enter into derivative contracts, or change the nature of our business. At December 31, 2002 and June 30, 2003, we were in compliance with all non-financial covenants under our credit facility.

Financial Covenants. Our credit facility contains covenants related to the satisfaction of financial ratios and compliance with financial tests, including ratios with respect to maximum leverage, minimum interest coverage and minimum fixed charge coverage. Our maximum leverage covenant requires that, as of the last day of each fiscal quarter, our ratio of total senior indebtedness (which excludes our 6% subordinated debentures) to consolidated EBITDA (as defined in our credit agreement) for the four immediately preceding fiscal quarters may not be greater than 5.00 to 1 through September 30, 2003, and the ratio declines on October 1 of each year thereafter. Our minimum interest coverage covenant requires that, as of the last day of each fiscal quarter, our ratio of consolidated EBITDA (as defined in our credit agreement) minus various capital expenditures, to consolidated senior interest expense (which excludes interest expense related to our 6% subordinated debentures) for the four immediately preceding fiscal quarters may not be less than 1.80 to 1 through September 30, 2003, and the ratio increases on October 1 of each year thereafter. Our minimum fixed charges coverage covenant requires that, as of the last day of each fiscal quarter, our ratio of consolidated EBITDA (as defined in our credit agreement) minus various capital expenditures and principal debt payments to fixed charges for the four immediately preceding fiscal quarters may not be less than the 1.00 to 1 through September 30, 2004, and the ratio increases on October 1 of each year thereafter. At December 31, 2002 and June 30, 2003, we were in compliance with all financial covenants under our credit facility.

Subordinated Debt

In June 2001, we issued an aggregate of $500.0 million of subordinated debentures to two of the partnerships affiliated with FL&Co. in connection with our acquisition of Citadel Communications. The partnerships affiliated with FL&Co. immediately distributed the subordinated debentures to their respective limited partners. The subordinated debentures are our general senior subordinated obligations, are not subject to mandatory redemption and mature in three equal annual installments beginning June 26, 2012, with the final payment due on June 26, 2014. The debentures bear interest at a fixed rate of 6% which is payable semi-annually at the end of June and December each year. The balance of debentures outstanding as of June 30, 2003 was $500.0 million. The subordinated debentures are subordinated to our credit facility and other senior obligations we may incur in the future and do not include any restrictive financial covenants. The subordinated debentures may be prepaid by us at any time without premium, penalty or charge. We have a right of first refusal on the transfer of the debentures.

Recent Accounting Pronouncements

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51, Consolidated Financial Statements*. This interpretation applies immediately to variable interest entities created after January 31, 2002 and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003 to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. This interpretation may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. Our adoption of FIN No. 46 is not expected to have a material impact on our financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment to Statement 133 on Derivative Instruments and Hedging Activities*. SFAS No. 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is applied prospectively and is effective for contracts entered into or modified after June 30, 2003, except for SFAS No. 133 implementation issues that have been effective for fiscal quarters that began prior to June 15, 2003 and certain provisions relating to forward purchases and sales of securities that do not yet exist. Our adoption of SFAS No. 149 will not have a material impact on our financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We will adopt the standard on July 1, 2003. We have not determined the effect, if any, that SFAS No. 150 will have on our consolidated financial statements.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with accounting principles generally accepted in the United States, which require us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosures of contingent assets and liabilities. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable judgments. Actual results could differ from these estimates under different assumptions and conditions.

We consider the following policies to be most critical in understanding the judgments involved in preparing our financial statements and the uncertainties that could affect our results of operations, financial condition and cash flows.

Allowance for Doubtful Accounts. We recognize an allowance for doubtful accounts based on historical experience of bad debts as a percent of its aged outstanding receivables. Based on historical information, we believe that our allowance is adequate. However, changes in general economic, business and market conditions could affect the ability of our customers to make their required payments; therefore, the allowance for doubtful accounts is reviewed monthly and changes to the allowance are updated as appropriate.

Long-Lived Assets. Our long-lived assets include FCC licenses, goodwill and other intangible assets. At June 30, 2003 and December 31, 2002, we had approximately $1,965.1 million and $1,987.5 million, respectively, in intangible assets, which represent approximately 90.2% and 90.4%, respectively, of our total assets. Prior to our adoption of SFAS No. 142, we determined the recoverability of all of our long-lived assets by comparing the carrying amount of an asset to the estimated future undiscounted cash flows expected to be generated by the asset. If the assets were considered to be impaired, the impairment recognized was measured by the amount by which the carrying amount of the assets exceeded the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. On January 1, 2002, we adopted SFAS No. 142 and have tested all intangible assets in accordance with the requirements of SFAS No. 142. Our policy for reviewing other long-lived assets for possible impairment has not changed. If our projections of future undiscounted cash flows were to deteriorate, this could result in an impairment of our long-lived assets.

Income Taxes. We utilize the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Contractual and Commercial Commitments

Due to the completion of our initial public offering in August of 2003 (See "Liquidity and Capital Resources Credit Facility"), the contractual commitments under our Notes Payable have been significantly reduced. As of June 30, 2003, we had $535.0 million outstanding under our Credit Facility and after the application of the net proceeds from the initial public offering we had $78.1 million outstanding.

As of June 30, 2003, we had four transactions pending to purchase an aggregate of fifteen radio stations. One of these transactions was an agreement to purchase five radio stations in the Des Moines, IA market, four radio stations in the New Orleans, LA market, and two radio stations in the Springfield, MO market for an aggregate cash purchase price of $133.0 million. This transaction was completed on September 8, 2003 primarily with borrowings under our credit facility. We have three additional transactions pending to purchase an aggregate of four radio stations in three markets for an aggregate cash purchase price of $25.1 million.

There have been no other significant changes in our contractual and commercial commitments as of June 30, 2003.

Off-Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements or transactions.

Seasonality

In the radio broadcasting industry, seasonal revenue fluctuations are common and are due primarily to variations in advertising expenditures by local and national advertisers. Typically, revenue is lowest in the first calendar quarter of the year and highest in the second and fourth calendar quarters of the year.

Impact of Inflation

We do not believe inflation has a significant impact on our operations. However, there can be no assurance that future inflation would not have an adverse impact on our operating results and financial condition.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a number of financial market risks in the ordinary course of business. We believe our primary financial market risk exposure pertains to interest rate changes, primarily as a result of our credit agreement, which bears interest based on variable rates. We have not taken any action to cover interest rate market risk, and are not a party to any interest rate market risk management activities. We have performed a sensitivity analysis assuming a hypothetical increase in interest rates of 100 basis points applied to the $535.0 million of variable rate debt that was outstanding as of June 30, 2003. Based on this analysis, the impact on future earnings for the following twelve months would be approximately $5.4 million of increased interest expense. This potential increase is based on certain simplifying assumptions, including a constant level of variable rate debt and a constant interest rate based on the variable rates in place as of June 30, 2003.

We believe our receivables do not represent a significant concentration of credit risk due to the wide variety of customers and markets in which we operate.

ITEM 4. CONTROLS AND PROCEDURES

Prior to the filing of this report, we carried out an evaluation, under the supervision and with the participation of the Company's management, including our Chief Executive Officer and our Principal Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934 (the "Exchange Act")). Based on this evaluation, which disclosed no significant deficiencies or material weaknesses, our Chief Executive Officer and our Principal Financial Officer concluded that, as of June 30, 2003, our disclosure controls and procedures were effective in timely alerting them to material information required to be included in our periodic SEC reports. Disclosure controls and procedures are controls and procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, including, without limitation, controls and procedures designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and our Principal Financial Officer, to allow timely decisions regarding required disclosure.

There have been no changes in our internal control over financial reporting during the period covered by this report or subsequent to the date of our Chief Executive Officer's and Principal Financial Officer's last evaluation that materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Our disclosure controls and procedures are designed to provide a reasonable level of assurance of reaching our desired disclosure objective and are effective in reaching that level of reasonable assurance.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In October 1999, the Radio Music License Committee (RMLC), of which we are a participant, filed a motion in the New York courts against Broadcast Music, Inc. (BMI) to commence a rate-making proceeding on behalf of the radio industry and to seek a determination of fair and reasonable industry-wide license fees for the broadcast of music. In July 2003, the RMLC entered into an agreement on behalf of the radio industry with BMI. This agreement, which is subject to approval by the United States District Court in New York, replaces the interim agreement under which we had been operating since January 1, 1997. We estimate that the impact of this agreement will not materially affect our financial position or results of operations.

In a complaint filed on June 5, 2003, with the United States District Court for the District of Connecticut, we were named as one of numerous defendants in litigation seeking monetary damages arising from the injuries and deaths of certain concertgoers at a Rhode Island nightclub. The complaint contains multiple causes of action, only a small number of which are brought against us, in which our sole involvement was to advertise the concert on one of our stations and to distribute promotional tickets provided by the organizers. The complaint alleges, among other things, that the organizers and sponsors of the concert failed to control crowd size, failed to obtain pyrotechnic permits, failed to inspect fireproofing at the club and failed to maintain emergency exits in workable condition, which contributed to the injuries and deaths of plaintiffs when pyrotechnic devices on the stage ignited soundproofing materials adjacent to the stage during the concert. The complaint alleges that we were a co-sponsor of the concert and asserts claims against us based on theories of joint venture liability and negligence. We believe that plaintiffs' claims against us are without merit and we intend to defend these claims vigorously.

We are subject to other claims and lawsuits arising in the ordinary course of our business. We believe that none of these legal proceedings would have a material adverse impact on our results of operations, cash flows or financial condition.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

The Securities and Exchange Commission declared our registration statement on Form S-1 (Registration No. 333-89844) under the Securities Act of 1933 in connection with the initial public offering of our common stock effective on July 31, 2003. Under this registration statement, we registered 25,300,000 shares of our common stock, including 3,300,000 shares subject to the underwriters' over-allotment option, with an aggregate public offering price of $480.7 million.

Our initial public offering commenced on August 1, 2003 and all of the shares of our common stock that we registered were sold for the aggregate public offering price of $480.7 million through an underwriting syndicate managed by Goldman, Sachs & Co., Credit Suisse First Boston LLC, Deutsche Bank Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Bear Stearns & Co. Inc., Citigroup Global Markets Inc., J.P. Morgan Securities Inc. and Wachovia Capital Markets, LLC. This offering terminated after the sale of all of the shares of our common stock that we registered under our registration statement on Form S-1.

The sale of shares of common stock by us, including the sale of 3,300,000 shares pursuant to the exercise of the over-allotment option by the underwriters, resulted in aggregate gross proceeds of approximately $480.7 million, approximately $28.8 million of which we applied to underwriting

commissions. As a result, we received approximately $451.9 million of the offering proceeds before legal, accounting and other related expenses.

On August 6, 2003, we used approximately $450.9 million of the net proceeds of the offering to repay amounts outstanding under our tranche B term loan and the revolving portion of our credit facility, with the remaining proceeds used to repay amounts outstanding under our tranche A term loan.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 23, 2003 a majority of stockholders adopted by written consent the Company's 2002 Long-Term Incentive Plan.

The results of voting on the adoption of the 2002 Long-Term Incentive Plan were as follows:

For	Against	Broker Non-Votes	Abstain/Withheld
288,402,987			

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

The following exhibits are filed herewith:

Exhibit Number **Exhibit Description**

3.1	Restated Certificate of Incorporation of Citadel Broadcasting Corporation.
3.2	Amended and Restated By-laws of Citadel Broadcasting Corporation.
10.5	Form of Indemnification Agreement between Citadel Broadcasting Corporation and certain directors and officers.
31.1	Certification of Chief Executive Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b)

Reports on Form 8-K

None.

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SIGNATURES

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

Date: September 15, 2003

CITADEL BROADCASTING CORPORATION
By: /s/ FARID SULEMAN

Farid Suleman
Chairman of the Board
Chief Executive Officer
(Principal Executive Officer)

Date: September 15, 2003

By: /s/ RANDY L. TAYLOR

Randy L. Taylor
Vice President Finance and Secretary
(Principal Financial and Accounting Officer)

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EXHIBIT INDEX

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outcome and impact on EOG cannot be predicted with certainty, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

10. Pension and Postretirement Benefits

Pension Plans.

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. For the nine months ended September 30, 2009 and 2008, EOG's total costs recognized for these pension plans were $15.2 million and $14.4 million, respectively.

In addition, as more fully discussed in Note 6 to Consolidated Financial Statements in EOG's 2008 Annual Report, EOG's Canadian, Trinidadian and United Kingdom subsidiaries maintain various pension and savings plans for most of their respective employees. For the nine months ended September 30, 2009 and 2008, combined contributions to these pension and savings plans were $1.8 million and $1.9 million, respectively.

Postretirement Plan.

EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents. For the nine months ended September 30, 2009, EOG's total contributions to these plans amounted to $97,000. The net periodic benefit costs recognized for these plans were $0.6 million and $0.5 million for the nine months ended September 30, 2009 and 2008, respectively.

11. Long-Term Debt and Common Stock

Long-Term Debt.

EOG utilizes commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper or uncommitted credit facilities at September 30, 2009. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for the nine months ended September 30, 2009 were 0.98% and 1.07%, respectively.

On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

EOG currently has a $1.0 billion unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement matures on June 28, 2012. At September 30, 2009, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate of the Agreement's administrative agent. At September 30, 2009, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 0.44% and 3.25%, respectively.

On May 11, 2009, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, amended its 3-year, $75 million Revolving Credit Agreement (Credit Agreement) to extend the scheduled maturity date of the remaining outstanding balance of $37 million from May 12, 2009 to May 12, 2010. Borrowings under the Credit Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate of the Credit Agreement's administrative agent. The applicable Eurodollar rate at September 30, 2009 was 2.75%. The weighted average Eurodollar rate for the amount outstanding during the first nine months of 2009 was 2.80%.

At September 30, 2009 and December 31, 2008, EOG had outstanding $2,797 million and $1,897 million, respectively, of long-term debt, which had estimated fair values of approximately $3,085 million and $1,933 million, respectively. The estimated fair value of long-term debt was based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at period-end.

Common Stock.

On February 4, 2009, EOG's Board of Directors increased the quarterly cash dividend on EOG's common stock from the previous $0.135 per share to $0.145 per share effective with the dividend paid on April 30, 2009 to record holders as of April 16, 2009.

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On October 7, 2009, EOG entered into an amendment (Amendment) to the Rights Agreement, dated as of February 14, 2000, as amended, by and between EOG and Computershare Trust Company, N.A., as the rights agent (Rights Agreement). The Amendment modifies the definition of "Qualified Institutional Investor" set forth in Section 1 of the Rights Agreement, specifically to delete from clause (A) of the exception to such definition the requirement that a person shall, subsequent to December 31, 2004, continuously beneficially own greater than five percent of the outstanding shares of EOG's common stock prior to the time of determination of such person's "Qualified Institutional Investor" status. Under the Rights Agreement, a person described in Rule 13d-l(b)(1) promulgated under the Securities Exchange Act of 1934 who is eligible to report beneficial ownership of EOG's common stock on Schedule 13G and who beneficially owns 15% or greater of EOG's outstanding common stock will nevertheless be deemed to be a "Qualified Institutional Investor" (and thus not an "Acquiring Person" which would trigger the protections of the Rights Agreement) if such person satisfies the amended exception to the "Qualified Institutional Investor" definition, including the requirement that such person beneficially own less than 30% of EOG's outstanding common stock.

12. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the accompanying Consolidated Balance Sheets. Effective January 1, 2008, EOG adopted the provisions of the Fair Value Measurements and Disclosures Topic of the ASC (ASC Topic 820) for its financial assets and liabilities. ASC Topic 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, ASC Topic 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. ASC Topic 820 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. EOG adopted the provisions of ASC Topic 820 relating to nonfinancial assets and liabilities effective January 1, 2009.

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The following table provides fair value measurement information within the hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at September 30, 2009 and December 31, 2008 (in millions):

	Fair Value Measurements Using:		
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
At September 30, 2009 Financial Assets:			

Natural gas collars, price swaps and basis swaps	$	-	$	290	$	-
Financial Liabilities:						
Natural gas collars, price swaps and basis swaps	$	-	$	41	$	-
Foreign currency rate swap	$	-	$	46	$	-
At December 31, 2008 Financial Assets:						
Natural gas collars, price swaps and basis swaps	$	-	$	836	$	-
Financial Liabilities:						
Natural gas collars, price swaps and basis swaps	$	-	$	12	$	-
Foreign currency rate swap	$	-	$	26	$	-

The estimated fair value of natural gas collar, price swap and basis swap contracts was based upon forward commodity price curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 7.

Proved oil and gas properties with a carrying amount of $50 million were written down to their fair value of $11 million, resulting in a pretax impairment charge of $39 million for the nine months ended September 30, 2009. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future natural gas and crude oil prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

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13. Risk Management Activities

Effective January 1, 2009, EOG adopted the expanded disclosure provisions of the Derivatives and Hedging Topic of the ASC. The new provisions require expanded disclosure about an entity's use of derivative instruments and hedging activities and the impact of those instruments on the consolidated financial statements. Information concerning EOG's derivative instruments and hedging activities is presented below.

Commodity Price Risk.

As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2008 Annual Report, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collar, price swap and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income. The related cash flow impact is reflected as Cash Flows from Operating Activities. In addition to financial transactions, from time to time, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

Foreign Currency Exchange Rate Risk.

As more fully described in Note 2 to the Consolidated Financial Statements included in EOG's 2008 Annual Report, EOG is party to a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the $150 million principal amount of notes issued by one of EOG's Canadian subsidiaries. EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of the Derivatives and Hedging Topic of the ASC. Changes in the fair value of the foreign currency swap do not impact Net Income Available to Common Stockholders. The after-tax net impact of the foreign currency swap transaction was an increase in Other Comprehensive Income of $58,000 and a reduction in Other Comprehensive Income of $1.1 million for the three months ended September 30, 2009 and 2008, respectively, and a $3.8 million increase in Other Comprehensive Income and a $3.4 million reduction in Other Comprehensive Income for the nine months ended September 30, 2009 and 2008, respectively (see Note 5).

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The following table sets forth the amount, on a gross basis, and classification of EOG's outstanding derivative financial instruments at September 30, 2009 and December 31, 2008. Certain amounts may be presented on a net basis in the consolidated financial statements in accordance with master netting arrangements between EOG and the counter-parties to the transactions (in millions):

Description	Location on Balance Sheet	Fair Value at September 30, 2009	Fair Value at December 31, 2008
Asset Derivatives			
Natural gas collars and price swaps -			
Current portion	Assets from Price Risk Management Activities	$ 324	$ 786
Noncurrent portion	Other Assets	$ -	$ 63
Liability Derivatives			
Natural gas basis swaps -			
Current portion	Liabilities from Price Risk Management Activities	$ 50	$ 11
Noncurrent portion	Other Liabilities	$ 25	$ 14
Foreign currency rate swaps -			
Noncurrent portion	Other Liabilities	$ 46	$ 26

EOG recognized a net gain on the mark-to-market of financial commodity derivative contracts of $406 million and $69 million for the nine months ended September 30, 2009 and 2008, respectively.

Financial Collar Contracts.

Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at September 30, 2009. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 was $10.33 per million British thermal units (MMBtu) and the average ceiling price was $12.63 per MMBtu.

Natural Gas Financial Collar Contracts

	Volume (MMBtud)	Floor Price: Floor Range ($/MMBtu)	Floor Price: Weighted Average Price ($/MMBtu)	Ceiling Price: Ceiling Range ($/MMBtu)	Ceiling Price: Weighted Average Price ($/MMBtu)
2010					
January	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55

On April 29, 2009, EOG settled its natural gas financial collar contracts with notional volumes of 40,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $26.5 million.

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Financial Price Swap Contracts.

Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at September 30, 2009. The notional volumes are expressed in MMBtud and prices are expressed in $/MMBtu. The average price of EOG's outstanding natural gas financial price swap contracts for 2009 was $9.83 per MMBtu and for 2010 was $10.14 per MMBtu.

Natural Gas Financial Price Swap Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2009		
January (closed)	585,000	$10.76
February (closed)	585,000	10.73
March (closed)	585,000	10.50
April (closed)	610,000	9.24
May (closed)	610,000	9.16
June (closed)	710,000	8.53
July (closed)	710,000	8.62
August (closed)	710,000	8.67
September (closed)	710,000	8.69
October (closed)	710,000	8.76
November	610,000	9.66

December	610,000	9.99
2010		
January	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21

On April 24, 2009, EOG settled its natural gas financial price swap contracts with notional volumes of 20,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $12.1 million.

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Financial Basis Swap Contracts.

Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at September 30, 2009. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap. Notional volumes are expressed in MMBtud and price differentials are expressed in $/MMBtu.

Natural Gas Financial Basis Swap Contracts

	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2009		
Second Quarter (closed)	65,000	$(2.54)
Third Quarter (closed)	65,000	(2.60)
Fourth Quarter (1)	65,000	(3.03)
2010		
First Quarter	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)

Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for October 2009.

Credit Risk.

Notional contract amounts are used to express the magnitude of commodity price and foreign currency swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by EOG's counterparties, are equal to the fair value of such contracts. EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk.

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association (ISDA) Master Agreements with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDA may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 12 for the aggregate fair value of all derivative instruments with credit-risk related contingent features that are in a net liability position at September 30, 2009 and December 31, 2008. EOG had zero collateral posted at both September 30, 2009 and December 31, 2008.

14. Acquisitions

During the third quarter of 2009, EOG completed three transactions to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas (Barnett Shale Combo Assets). The Barnett Shale Combo Assets consist of proved developed and undeveloped reserves and unproved acreage. The aggregate purchase price of the transactions, which is subject to customary post-closing adjustments, totaled $196.7 million, consisting of cash consideration of $107.1 million and 1,450,000 shares of EOG common stock valued at $89.6 million at the closing date of the applicable transaction.

PART I. FINANCIAL INFORMATION

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
EOG RESOURCES, INC.

Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) oil and natural gas companies in the United States with proved reserves in the United States, Canada, Trinidad, the United Kingdom and China. EOG operates under a consistent business and operational strategy that focuses predominantly on achieving a strong reinvestment rate of return, drilling internally generated prospects, delivering long-term production growth and maintaining a strong balance sheet.

United States and Canada. EOG's effort to identify plays with larger reserve potential has proven a successful supplement to its base development and exploitation program in the United States and Canada. EOG continues to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's natural gas and crude oil production. Production in the United States and Canada accounted for approximately 86% of total company production in the first nine months of both 2009 and 2008. One of EOG's exploration strategies is to apply its horizontal drilling expertise gained in natural gas resource plays to unconventional oil reservoirs. During the first nine months of 2009, the Fort Worth Basin Barnett Shale and North Dakota Bakken areas produced an increasing amount of crude oil and natural gas liquids as compared to the comparable period in 2008. For the first nine months of 2009, crude oil and natural gas liquids production accounted for approximately 22% of total company production as compared to approximately 18% for the comparable period in 2008. Based on current trends, EOG expects its 2009 crude oil and natural gas liquids production to continue to increase as compared to 2008. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

During the third quarter of 2009, EOG completed three transactions to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas (Barnett Shale Combo Assets). The Barnett Shale Combo Assets consist of proved developed and undeveloped reserves and approximately 33,000 net unproved acres. Production from these assets averaged approximately 2,300 barrels equivalent per day, net, at the time of acquisition. The aggregate purchase price of the transactions, which is subject to customary post-closing adjustments, totaled $196.7 million, consisting of cash consideration of $107.1 million and 1,450,000 shares of EOG common stock valued at $89.6 million at the closing date of the applicable transaction.

International. In the United Kingdom, EOG completed a farm-in agreement with owners of the Central North Sea Block 15/30a Area AB during the third quarter of 2009. An exploratory well, which EOG will operate with a 65% working interest, is planned for the fourth quarter of 2009. Subsequent to its June 2009 oil discovery in the East Irish Sea Block 110/12, EOG plans to drill two additional exploratory wells during the fourth quarter of 2009 and first quarter of 2010. EOG has a 100% working interest in this Block. In the Sichuan Basin, Sichuan Province, The People's Republic of China, EOG drilled a horizontal well in the third quarter of 2009 and plans to complete and test this well during the fourth quarter of 2009 and first quarter of 2010. In addition, to evaluate a different zone, EOG began drilling a second monitoring well during the third quarter of 2009 and plans to begin a second horizontal well in the fourth quarter of 2009.

EOG continues to evaluate other select natural gas and crude oil opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous natural gas and crude oil reserves have been identified.

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Capital Structure. One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. At September 30, 2009, EOG's debt-to-total capitalization ratio was 23% as compared to 17% at December 31, 2008. On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings. During the first nine months of 2009, EOG funded $2.7 billion in exploration and development and other property, plant and equipment expenditures (including $206 million of acquisitions) and paid $106 million in dividends to common stockholders, primarily by utilizing cash provided from its operating activities, proceeds from commercial paper and uncommitted credit facility borrowings and proceeds from the offering of the Notes.

For 2009, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $3.7 billion, including acquisitions of approximately $300 million. United States and Canada natural gas and crude oil drilling activity continues to be a key component of these expenditures. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

Results of Operations

The following review of operations for the three and nine months ended September 30, 2009 and 2008 should be read in conjunction with the consolidated financial statements of EOG and notes thereto included in this Quarterly Report on Form 10-Q.

Three Months Ended September 30, 2009 vs. Three Months Ended September 30, 2008

Net Operating Revenues.

During the third quarter of 2009, net operating revenues decreased $2,257 million, or 69%, to $1,007 million from $3,264 million for the same period of 2008. Total wellhead revenues for the third quarter of 2009, which are revenues generated from sales of natural gas, crude oil and condensate and natural gas liquids, decreased $985 million, or 54%, to $849 million from $1,834 million for the same period of 2008. During the third quarter of 2009, EOG recognized a net gain on mark-to-market commodity derivative contracts of $21 million compared to a net gain of $1,382 million for the same period of 2008. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party natural gas, crude oil and natural gas liquids as well as gathering fees associated with gathering third-party natural gas, for the third quarter of 2009 increased $84 million, or 163%, to $135 million from $51 million for the same period of 2008.

Wellhead volume and price statistics for the three-month periods ended September 30, 2009 and 2008 were as follows:

	Three Months Ended September 30,	
	2009	2008
Natural Gas Volumes (MMcfd) (1)		
United States	1,128	1,196
Canada	219	224
Trinidad	268	240
Other International (2)	13	19

Total	1,628	1,679
Average Natural Gas Prices ($/Mcf) (3)		
United States	$ 3.27	$ 8.99
Canada	3.15	8.15
Trinidad	1.77	4.04
Other International (2)	3.53	7.41
Composite	3.01	8.15
Crude Oil and Condensate Volumes (MBbld) (1)		
United States	51.7	41.8
Canada	4.7	3.0
Trinidad	3.0	3.4
Other International (2)	0.1	0.1
Total	59.5	48.3
Average Crude Oil and Condensate Prices ($/Bbl) (3)		
United States	$60.79	$109.86
Canada	61.43	109.71
Trinidad	57.07	111.39
Other International (2)	57.93	112.77
Composite	60.65	109.96
Natural Gas Liquids Volumes (MBbld) (1)		
United States	23.1	13.2
Canada	1.0	1.1

Total	24.1	14.3
Average Natural Gas Liquids Prices ($/Bbl) (3)		
United States	$31.15	$ 69.79
Canada	30.96	64.01
Composite	31.14	69.33
Natural Gas Equivalent Volumes (MMcfed) (4)		
United States	1,577	1,525
Canada	253	249
Trinidad	286	261
Other International (2)	13	20
Total	2,129	2,055
Total Bcfe (4)	195.9	189.1

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) Dollars per thousand cubic feet or per barrel, as applicable.
(4) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil, condensate and natural gas liquids. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil, condensate or natural gas liquids.

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Wellhead natural gas revenues for the third quarter of 2009 decreased $809 million, or 64%, to $450 million from $1,259 million for the same period of 2008. The decrease was due to a lower composite average wellhead natural gas price ($770 million) and decreased natural gas deliveries ($39 million). EOG's composite average wellhead natural gas price decreased 63% to $3.01 per thousand cubic feet (Mcf) for the third quarter of 2009 from $8.15 per Mcf for the same period of 2008.

Natural gas deliveries for the third quarter of 2009 decreased 51 MMcfd, or 3%, to 1,628 MMcfd from 1,679 MMcfd for the same period of 2008. The decrease was primarily due to lower production in the United States (68 MMcfd), Canada (5 MMcfd) and the United Kingdom (5

MMcfd), partially offset by increased production in Trinidad (28 MMcfd). The decrease in the United States was primarily attributable to decreased production in Texas (50 MMcfd), the Rocky Mountain area (14 MMcfd), New Mexico (8 MMcfd), Kansas (5 MMcfd) and Mississippi (3 MMcfd), partially offset by increased production in Louisiana (14 MMcfd). The decrease in the United Kingdom primarily resulted from reduced production in the Arthur field. The increase in Trinidad was primarily due to increased net contractual deliveries.

Wellhead crude oil and condensate revenues for the third quarter of 2009 decreased $153 million, or 32%, to $330 million from $483 million for the same period of 2008, due to a lower composite average wellhead crude oil and condensate price ($268 million), partially offset by an increase of 11 MBbld, or 23%, in wellhead crude oil and condensate deliveries ($115 million). The increase in deliveries primarily reflects increased production in North Dakota (9 MBbld), Texas (2 MBbld) and Canada (2 MBbld). The composite average wellhead crude oil and condensate price for the third quarter of 2009 decreased 45% to $60.65 per barrel compared to $109.96 per barrel for the same period of 2008.

Natural gas liquids revenues for the third quarter of 2009 decreased $22 million, or 24%, to $69 million from $91 million for the same period of 2008, due to a lower composite average price ($84 million), partially offset by an increase of 10 MBbld, or 69%, in natural gas liquids deliveries ($62 million). The composite average natural gas liquids price for the third quarter of 2009 decreased 55% to $31.14 per barrel compared to $69.33 per barrel for the same period of 2008. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area (6 MBbld) and the Mid-Continent area (2 MBbld).

During the third quarter of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $21 million compared to a net gain of $1,382 million for the same period of 2008. During the third quarter of 2009, the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts was $331 million compared to the net cash outflow related to settled natural gas and crude oil financial price swap contracts of $122 million for the same period of 2008.

Gathering, processing and marketing revenues represent sales of third-party natural gas, crude oil and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. During the three months ended September 30, 2009 and 2008, substantially all of such revenues were related to sales of third-party natural gas and crude oil. Marketing costs represent the costs of purchasing third-party natural gas and crude oil and the associated transportation costs.

Gathering, processing and marketing revenues less marketing costs for the third quarter of 2009 decreased $4 million to $3 million compared to $7 million for the same period of 2008, reflecting lower margins associated with natural gas marketing activities.

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Operating and Other Expenses.

For the third quarter of 2009, operating expenses of $972 million were $100 million higher than the $872 million incurred in the third quarter of 2008. The following table presents the costs per thousand cubic feet equivalent (Mcfe) for the three-month periods ended September 30, 2009 and 2008:

	Three Months Ended September 30,	
	2009	2008
	$ 0.73	$ 0.75

Lease and Well		
Transportation Costs	0.36	0.41
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	1.84	1.73
Other Property, Plant and Equipment	0.13	0.10
General and Administrative (G&A)	0.32	0.38
Interest Expense, Net	0.16	0.06
Total (1)	$ 3.54	$ 3.43

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net for the three months ended September 30, 2009 compared to the same period of 2008 are set forth below.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain EOG's natural gas and crude oil wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance expenses include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are costs of operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuate from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses were $142 million for the third quarter of both 2009 and 2008. During 2009, increased operating and maintenance expenses in Canada ($5 million) and China ($1 million) and increased lease and well administrative expenses in Canada ($1 million) were offset by decreased lease and well administrative expenses in the United States ($3 million), decreased operating and maintenance expenses in the United States ($2 million) and changes in the Canadian exchange rate ($2 million).

Transportation costs represent costs incurred directly by EOG from third-party carriers associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees, fuel costs and transportation fees.

Transportation costs of $71 million for the third quarter of 2009 decreased $7 million from $78 million for the same prior year period primarily due to decreased costs associated with marketing arrangements to transport production from the Fort Worth Basin Barnett Shale area ($10 million) to downstream markets, partially offset by increased costs associated with marketing arrangements to transport production from the Rocky Mountain area ($5 million) to downstream markets.

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DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells, reserve revisions (upward or downward) primarily related to well performance and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from year to year. DD&A of the cost of other property, plant and equipment is calculated using the straight-line depreciation method over the useful lives of the assets. Other property, plant and equipment consist of natural gas gathering and processing facilities, compressors, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses for the third quarter of 2009 increased $39 million to $385 million from $346 million for the same prior year period. DD&A expenses associated with oil and gas properties for the third quarter of 2009 were $32 million higher than the same prior year period primarily due to higher unit rates in the United States ($18 million), Trinidad ($3 million) and Canada ($3 million) and as a result of increased production in the United States ($9 million), partially offset by changes in the Canadian exchange rate ($3 million).

DD&A expenses associated with other property, plant and equipment for the third quarter of 2009 were $7 million higher than the same prior year period primarily due to increased expenditures associated with natural gas gathering systems and processing plants in the Fort Worth Basin Barnett Shale area ($3 million) and Rocky Mountain area ($3 million).

G&A expenses of $63 million for the third quarter of 2009 decreased $8 million from the same prior year period primarily due to lower employee-related costs.

Interest expense, net of $30 million for the third quarter of 2009 increased $18 million compared to the same prior year period primarily due to a higher average debt balance ($20 million), partially offset by higher capitalized interest ($2 million).

Gathering and processing costs represent operating and maintenance expenses and administrative expenses associated with operating EOG's natural gas gathering and processing assets.

Gathering and processing costs for the third quarter of 2009 increased $4 million to $13 million as compared to the same prior year period primarily due to increased activities in the Rocky Mountain area.

Exploration costs of $45 million for the third quarter of 2009 increased $7 million from the same prior year period primarily due to increased geological and geophysical expenditures in the United States ($4 million) and the United

Kingdom ($2 million).

Impairments include amortization and impairments of unproved oil and gas properties, as well as impairments of proved oil and gas properties. Unproved properties with individually significant acquisition costs are assessed on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the average holding period. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

Impairments of $69 million for the third quarter of 2009 increased $37 million from $32 million for the same prior year period primarily due to increased amortization and impairments of unproved properties in the United States ($28 million) and increased impairments of proved properties in the United States ($8 million). EOG recorded impairments of proved properties of $15 million and $7 million for the third quarter of 2009 and 2008, respectively.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are determined based on wellhead revenues and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

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Taxes other than income for the third quarter of 2009 decreased $50 million to $48 million (5.6% of wellhead revenues) from $98 million (5.3% of wellhead revenues) for the same prior year period. The decrease in taxes other than income was primarily due to a decrease in severance/production taxes as a result of decreased wellhead revenues in the United States ($33 million) and Trinidad ($4 million) and an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions ($12 million).

Other income (expense), net for the third quarter of 2009 decreased $14 million from the same prior year period. The decrease was primarily due to lower equity income from ammonia plants in Trinidad ($7 million) and lower interest income ($3 million).

EOG recognized an income tax provision of less than $1 million for the third quarter of 2009 compared to $838 million for the same prior year period. The change was primarily due to decreased pretax income. The net effective tax rate for the third quarter of 2009 decreased to 8% from 35% for the same prior year period due primarily to lower pretax income and lower Canadian taxes.

Nine Months Ended September 30, 2009 vs. Nine Months Ended September 30, 2008

Net Operating Revenues.

During the first nine months of 2009, net operating revenues decreased $2,467 million, or 45%, to $3,026 million from $5,493 million for the same period of 2008. Total wellhead revenues for the first nine months of 2009 decreased $2,767 million, or 54%, to $2,364 million from $5,131 million for the same period of 2008. During the first nine months of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $406 million compared to a net gain of $69 million for the same period of 2008. Gathering, processing and marketing revenues for the first nine months of 2009 increased $99 million, or 66%, to $250 million from $151 million for the same period of 2008. Other, net operating revenues in 2008 primarily consist of a gain of $128 million on the sale of EOG's Appalachian assets in February 2008.

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Wellhead volume and price statistics for the nine-month periods ended September 30, 2009 and 2008 were as follows:

	Nine Months Ended September 30,	
	2009	2008
Natural Gas Volumes (MMcfd)		
United States	1,153	1,141
Canada	224	218
Trinidad	266	229
Other International	15	16
Total	1,658	1,604
Average Natural Gas Prices ($/Mcf)		
United States	$ 3.57	$ 9.15
Canada	3.67	8.33
Trinidad	1.54	3.86
Other International	4.45	8.90
Composite	3.27	8.28
Crude Oil and Condensate Volumes (MBbld)		
United States	46.5	35.9
Canada	3.6	2.7
Trinidad	3.0	3.4
Other International	0.1	0.1
Total	53.2	42.1
Average Crude Oil and Condensate Prices ($/Bbl)		
	$49.54	$107.36

United States		
Canada	51.91	104.57
Trinidad	46.13	103.80
Other International	50.11	104.66
Composite	49.51	106.89
Natural Gas Liquids Volumes (MBbld)		
United States	22.2	14.7
Canada	1.1	1.0
Total	23.3	15.7
Average Natural Gas Liquids Prices ($/Bbl)		
United States	$26.42	$ 63.08
Canada	27.29	62.45
Composite	26.46	63.04
Natural Gas Equivalent Volumes (MMcfed)		
United States	1,566	1,445
Canada	252	240
Trinidad	284	250
Other International	15	16
Total	2,117	1,951
Total Bcfe	578.1	534.5

Wellhead natural gas revenues for the first nine months of 2009 decreased $2,159 million, or 59%, to $1,478 million from $3,637 million for the same period of 2008. The decrease was due to a lower composite average wellhead natural gas price ($2,268 million), partially offset by increased natural gas deliveries ($109 million). EOG's composite average wellhead natural gas price decreased 61% to $3.27 per Mcf for the first nine months of 2009 from $8.28 per Mcf for the same period of 2008.

Natural gas deliveries for the first nine months of 2009 increased 54 MMcfd, or 3%, to 1,658 MMcfd from 1,604 MMcfd for the same period of 2008. The increase was due to higher production in Trinidad (37 MMcfd), the United States (12 MMcfd) and Canada (6 MMcfd). The increase in Trinidad was primarily due to increased net contractual deliveries and reduced plant shutdowns for maintenance during 2009. The increase in the United States was primarily attributable to increased production in the Rocky Mountain area (15 MMcfd), Texas (12 MMcfd) and Louisiana (6 MMcfd), partially offset by decreased production in Mississippi (7 MMcfd), New Mexico (5 MMcfd), Oklahoma (3 MMcfd), Kansas (3 MMcfd) and as a result of the February 2008 sale of EOG's Appalachian assets (3 MMcfd). The increase in Canada was primarily attributable to British Columbia Horn River Basin production.

Wellhead crude oil and condensate revenues for the first nine months of 2009 decreased $505 million, or 41%, to $718 million from $1,223 million for the same period of 2008, due to a lower composite average wellhead crude oil and condensate price ($832 million), partially offset by an increase of 11 MBbld, or 26%, in wellhead crude oil and condensate deliveries ($327 million). The increase in deliveries primarily reflects increased production in North Dakota (9 MBbld) and Texas (2 MBbld). The composite average wellhead crude oil and condensate price for the first nine months of 2009 decreased 54% to $49.51 per barrel compared to $106.89 per barrel for the same period of 2008.

Natural gas liquids revenues for the first nine months of 2009 decreased $103 million, or 38%, to $168 million from $271 million for the same period of 2008, due to a lower composite average price ($233 million), partially offset by an increase of 8 MBbld, or 48%, in natural gas liquids deliveries ($130 million). The composite average natural gas liquids price for the first nine months of 2009 decreased 58% to $26.46 per barrel compared to $63.04 per barrel for the same period of 2008. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area.

During the first nine months of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $406 million compared to a net gain of $69 million for the same period of 2008. During the first nine months of 2009, the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts was $987 million compared to a net cash outflow related to settled natural gas and crude oil financial price swap contracts of $237 million for the same period of 2008.

Gathering, processing and marketing revenues less marketing costs for the first nine months of 2009 increased $1 million to $12 million compared to the same prior year period of 2008. The increase resulted primarily from increased natural gas marketing operations in the Gulf Coast area.

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Operating and Other Expenses.

For the first nine months of 2009, operating expenses of $2,709 million were $232 million higher than the $2,477 million incurred in the same period of 2008. The following table presents the costs per Mcfe for the nine-month periods ended September 30, 2009 and 2008:

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Lease and Well	$ 0.73	$ 0.74
Transportation Costs	0.36	0.38
DD&A -		
Oil and Gas Properties	1.87	1.71
Other Property, Plant and Equipment	0.12	0.09
G&A	0.31	0.35
Interest Expense, Net	0.13	0.06
Total (1)	$ 3.52	$ 3.33

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net for the nine months ended September 30, 2009 compared to the same period of 2008 are set forth below.

Lease and well expenses of $422 million for the first nine months of 2009 increased $26 million from $396 million for the same prior year period primarily due to higher operating and maintenance expenses in the United States ($25 million), Canada ($11 million) and China ($3 million), partially offset by changes in the Canadian exchange rate ($13 million).

Transportation costs of $206 million for the first nine months of 2009 increased $3 million from $203 million for the same prior year period primarily due to increased transportation costs in the United States ($4 million) and Trinidad ($1 million), partially offset by decreased transportation costs in the United Kingdom ($1 million) and Canada ($1 million). The increased transportation costs in the United States were primarily due to increased transportation costs in the Rocky Mountain area ($11 million), partially offset by decreased transportation costs in the Fort Worth Basin Barnett Shale area ($4 million).

DD&A expenses for the first nine months of 2009 increased $191 million to $1,150 million from $959 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first nine months of 2009 were $166 million higher than the same prior year period primarily due to higher unit rates in the United States ($92 million), Canada ($11 million), Trinidad ($10 million) and China ($3 million) and increased production in the United States ($60 million), Canada ($6 million) and in Trinidad ($2 million), partially offset by changes in the Canadian exchange rate ($21 million).

DD&A expenses associated with other property, plant and equipment for the first nine months of 2009 were $25 million higher than the same prior year period primarily due to increased expenditures associated with natural gas gathering systems and processing plants in the Fort Worth Basin Barnett Shale area ($11 million) and Rocky Mountain area ($7 million).

G&A expenses of $179 million for the first nine months of 2009 decreased $6 million from the same prior year period primarily due to lower employee-related costs.

Interest expense, net of $74 million for the first nine months of 2009 increased $40 million compared to the same prior year period primarily due to a higher average debt balance ($48 million), partially offset by higher capitalized interest ($8 million).

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Gathering and processing costs for the first nine months of 2009 increased $18 million to $45 million as compared to the same prior year period primarily due to increased activities in the Rocky Mountain area ($11 million) and the Fort Worth Basin Barnett Shale area ($6 million).

Exploration costs of $129 million for the first nine months of 2009 decreased $17 million compared to the same prior year period primarily due to decreased geological and geophysical expenditures in the United States.

Impairments of $182 million for the first nine months of 2009 increased $68 million compared to the same prior year period primarily due to increased amortization and impairments of unproved properties in the United States ($69 million) and increased impairments of proved properties in the United States ($20 million), partially offset by an impairment in Trinidad recorded in the second quarter of 2008 as a result of EOG's relinquishment of its rights to Block Lower Reverse "L" (LRL) ($20 million). EOG recorded impairments of proved properties of $39 million and $40 million for the nine months ended September 30, 2009 and 2008, respectively.

Taxes other than income for the first nine months of 2009 decreased $161 million to $119 million (5.0% of wellhead revenues) from $280 million (5.5% of wellhead revenues) for the same prior year period. The decrease in taxes other than income was primarily due to decreased severance/production taxes primarily as a result of decreased wellhead revenues in the United States ($103 million) and Trinidad ($16 million), an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions ($32 million) and lower ad valorem/property taxes in the United States ($13 million), partially offset by an increase in franchise taxes in the United States ($5 million). The decline in taxes other than income as a percentage of wellhead revenues primarily reflects an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions combined with a decline in non-revenue based taxes.

Other income (expense), net was $3 million for the first nine months of 2009 compared to $29 million for the same prior year period. The decrease of $26 million was primarily due to lower equity income from ammonia plants in Trinidad ($17 million), lower interest income ($6 million) and settlements received related to the Enron Corp. bankruptcy in the second quarter of 2008 ($2 million), partially offset by increased foreign currency transaction gains ($5 million).

Income tax provision of $100 million for the first nine months of 2009 decreased $936 million compared to $1,036 million for the same prior year period due primarily to decreased pretax income ($968 million), partially offset by higher foreign taxes ($28 million). The net effective tax rate for the first nine months of 2009 increased to 41% from 34% for the same prior year period primarily as a result of higher state and foreign tax rates and the absence of 2008 tax benefits related to the impairment of LRL.

Capital Resources and Liquidity

Cash Flow.

The primary sources of cash for EOG during the nine months ended September 30, 2009 were funds generated from operations, net commercial paper and uncommitted credit facility borrowings and proceeds from the offering of the Notes. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; and dividend payments to stockholders. During the first nine months of 2009, EOG's cash balance increased $278 million to $609 million from $331 million at December 31, 2008.

Net cash provided by operating activities of $2,094 million for the first nine months of 2009 decreased $1,506 million compared to the same period of 2008 primarily reflecting a decrease in wellhead revenues ($2,767 million), unfavorable changes in working capital and other assets and liabilities ($62 million) and an increase in cash paid for interest expense ($8 million), partially offset by a favorable change in net cash flow from the settlement of financial commodity derivative contracts ($1,224 million), a decrease in cash operating expenses ($137 million) and a decrease in net cash paid for income taxes ($31 million).

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Net cash used in investing activities of $2,651 million for the first nine months of 2009 decreased by $848 million compared to the same period of 2008 due primarily to a decrease in additions to oil and gas properties ($1,264 million) and a decrease in additions to other property, plant and equipment ($80 million), partially offset by a decrease in proceeds from sales of assets ($367 million), primarily reflecting net proceeds from the sale of EOG's Appalachian assets in February 2008, and unfavorable changes in working capital associated with investing activities ($132 million).

Net cash provided by financing activities was $823 million for the first nine months of 2009 compared to $745 million for the same period of 2008. Cash provided by financing activities for the first nine months of 2009 included the proceeds from the offering of the Notes ($900 million), excess tax benefits from stock-based compensation ($34 million) and proceeds from stock options exercised and employee stock purchase plan activity ($14 million). Cash used by financing activities for the first nine months of 2009 included cash dividend payments ($106 million), the purchase of treasury stock ($10 million) and debt issuance costs ($9 million).

Total Expenditures.

For 2009, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $3.7 billion, including acquisitions of approximately $300 million. The table below sets out components of total expenditures for the nine-month periods ended September 30, 2009 and 2008 (in millions):

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Expenditure Category		
Capital		
Drilling and Facilities	$ 1,780	$ 2,988
Leasehold Acquisitions	293	377
Property Acquisitions	206	109
Capitalized Interest	38	30
Subtotal	2,317	3,504
Exploration Costs	129	145
Dry Hole Costs	40	28
Exploration and Development Expenditures	2,486	3,677
Asset Retirement Costs	53	164
Total Exploration and Development Expenditures	2,539	3,841
Other Property, Plant and Equipment	241	321
Total Expenditures	$ 2,780	$ 4,162

Exploration and development expenditures of $2,486 million for the first nine months of 2009 were $1,191 million lower than the same period of 2008 due primarily to decreased drilling and facilities expenditures in the United States ($1,150 million), Trinidad ($42 million) and Canada ($29 million), decreased leasehold acquisition expenditures in Canada ($105 million), changes in the foreign currency exchange rate in Canada ($27 million) and the United Kingdom ($5 million), decreased geological and geophysical expenditures in the United States ($17 million) and decreased property acquisition expenditures in Trinidad ($15 million) and Canada ($14 million). These decreases were partially offset by increased property acquisition expenditures in the United States ($136 million), increased leasehold acquisition expenditures in the United States ($27 million), increased drilling and facilities expenditures in China ($24 million) and the United Kingdom ($14 million), increased capitalized interest in the United States ($10 million) and increased dry hole costs in the United Kingdom ($9 million) and the United States ($8 million). The exploration and development expenditures for the first nine months of 2009 of $2,486 million included $1,589 million in development, $653 million in exploration, $206 million in property acquisitions and $38 million in capitalized interest. The exploration and development expenditures for the first nine months of 2008 of $3,677 million included $2,722 million in development, $816 million in exploration, $109 million in property acquisitions and $30 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad, the United Kingdom and China, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Commodity Derivative Transactions.

As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 25, 2009, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collar, price swap and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income. The related cash flow impact is reflected as Cash Flows from Operating Activities. In addition to financial transactions, from time to time, EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

Financial Collar Contracts. The total fair value of EOG's natural gas financial collar contracts at September 30, 2009 was a positive $32 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at November 5, 2009. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 is $10.33 per million British thermal units (MMBtu) and the average ceiling price is $12.63 per MMBtu.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55

On April 29, 2009, EOG settled its natural gas financial collar contracts with notional volumes of 40,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $26.5 million.

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Financial Price Swap Contracts.

The total fair value of EOG's natural gas financial price swap contracts at September 30, 2009 was a positive $292 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at November 5, 2009. The notional volumes are expressed in MMBtud and prices are expressed in $/MMBtu. The average price of EOG's outstanding natural gas financial price swap contracts for 2009 is $9.99 per MMBtu and for 2010 is $10.14 per MMBtu.

Natural Gas Financial Price Swap Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2009		
January (closed)	585,000	$10.76
February (closed)	585,000	10.73
March (closed)	585,000	10.50
April (closed)	610,000	9.24
May (closed)	610,000	9.16
June (closed)	710,000	8.53
July (closed)	710,000	8.62
August (closed)	710,000	8.67
September (closed)	710,000	8.69
October (closed)	710,000	8.76
November (closed)	610,000	9.66
December	610,000	9.99
2010		
January	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21

On April 24, 2009, EOG settled its natural gas financial price swap contracts with notional volumes of 20,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $12.1 million.

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Financial Basis Swap Contracts.

Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG has entered into natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. The total fair value of EOG's natural gas financial basis swap contracts at September 30, 2009 was a negative $75 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at November 5, 2009. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap. The notional volumes are expressed in MMBtud and price differentials expressed in $/MMBtu.

Natural Gas Financial Basis Swap Contracts

	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2009		
Second Quarter (closed)	65,000	$(2.54)
Third Quarter (closed)	65,000	(2.60)
Fourth Quarter (1)	65,000	(3.03)
2010		
First Quarter	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for the months of October and November 2009.

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Information Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, budgets, reserve information, levels of production and costs and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "goal," "may," "will" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production or generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that these expectations will be achieved or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known and unknown risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing and extent of changes in prices for natural gas, crude oil and related commodities;
- changes in demand for natural gas, crude oil and related commodities, including ammonia and methanol;
- the extent to which EOG is successful in its efforts to discover, develop, market and produce reserves and to acquire natural gas and crude oil properties;

- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling and advanced completion technologies;

- the extent to which EOG is successful in its efforts to economically develop its acreage in the Barnett Shale, the Bakken Formation, its Horn River Basin and Haynesville plays and its other exploration and development areas;

- EOG's ability to achieve anticipated production levels from existing and future natural gas and crude oil development projects, given the risks and uncertainties inherent in drilling, completing and operating natural gas and crude oil wells and the potential for interruptions of production, whether involuntary or intentional as a result of market or other conditions;

- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;

- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights of way;

- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;

- EOG's ability to obtain access to surface locations for drilling and production facilities;

- the extent to which EOG's third-party-operated natural gas and crude oil properties are operated successfully and economically;

- EOG's ability to effectively integrate acquired natural gas and crude oil properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;

- weather, including its impact on natural gas and crude oil demand, and weather-related delays in drilling and in the installation and operation of gathering and production facilities;

- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;

- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all;

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;

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- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;

- the extent and effect of any hedging activities engaged in by EOG;

- the timing and impact of liquefied natural gas imports;
- the use of competing energy sources and the development of alternative energy sources;
- political developments around the world, including in the areas in which EOG operates;
- changes in government policies, legislation and regulations, including environmental regulations;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors," on pages 13 through 19 of EOG's Annual Report on Form 10-K for the year ended December 31, 2008 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made and EOG undertakes no obligation to update or revise its forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
EOG RESOURCES, INC.

EOG's exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk is discussed in (i) the "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" sections of "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity," on pages 36 through 42 of EOG's Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 25, 2009 (EOG's 2008 Annual Report); and (ii) Note 11, "Price, Interest Rate and Credit Risk Management Activities," on pages F-26 through F-29, to EOG's Consolidated Financial Statements included in EOG's 2008 Annual Report. There have been no material changes in this information. For additional information regarding EOG's financial commodity derivative contracts and physical commodity contracts, see (i) Note 13 to Consolidated Financial Statements in this Quarterly Report on Form 10-Q; (ii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Net Operating Revenues" in this Quarterly Report on Form 10-Q; and (iii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions" in this Quarterly Report on Form 10-Q.

ITEM 4. CONTROLS AND PROCEDURES
EOG RESOURCES, INC.

Disclosure Controls and Procedures.

EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this Quarterly Report on Form 10-Q (Evaluation Date). Based on this evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date in ensuring that information that is required to be disclosed by EOG in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EOG's management as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting.

There were no changes in EOG's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act) that occurred during the quarterly period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

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PART II. OTHER INFORMATION

EOG RESOURCES, INC.

ITEM 1. LEGAL PROCEEDINGS

See Part I, Item 1, Note 9 to Consolidated Financial Statements, which is incorporated herein by reference.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under The Plans or Programs (2)
July 1, 2009 - July 31, 2009	2,203	$ 72.97	-	6,386,200
	44,063	76.62	-	6,386,200

August 1, 2009 - August 31, 2009				
September 1, 2009 - September 30, 2009	2,869	78.86	-	6,386,200
Total	49,135	76.59	-	

(1) Represents 49,135 total shares for the quarter ended September 30, 2009 that consist solely of shares that were withheld by or returned to EOG
(i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights
or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares
do not count against the 10 million aggregate share authorization by EOG's Board of Directors (Board) discussed below.
(2) In September 2001, the Board authorized the repurchase of up to 10 million shares of EOG's common stock. During the third quarter of 2009,
EOG did not repurchase any shares under the Board-authorized repurchase program.

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ITEM 6. EXHIBITS

Exhibit No.		Description
4.1	-	Amendment No. 7 to Rights Agreement, dated as of October 7, 2009, between EOG and Computershare Trust Company, N.A., as rights agent (via succession) (incorporated by reference to Exhibit 4.12 to EOG's Current Report on Form 8-K, filed October 7, 2009).
* 31.1	-	Section 302 Certification of Periodic Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Periodic Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Periodic Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Periodic Report of Principal Financial Officer.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.

* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

* Exhibits filed herewith

** Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income - Three Months Ended September 30, 2009 and 2008 and Nine Months Ended September 30, 2009 and 2008, (ii) the Consolidated Balance Sheets - September 30, 2009 and December 31, 2008, (iii) the Consolidated Statements of Cash Flows - Nine Months Ended September 30, 2009 and 2008 and (iv) Notes to Consolidated Financial Statements. Users of this data are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

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SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: November 5, 2009 By: /s/ TIMOTHY K. DRIGGERS

Timothy K. Driggers
Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer and Duly Authorized Officer)

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EXHIBIT INDEX

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