MARATHON OIL CORP
Form 10-Q
November 07, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2006

OR

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

For the transition period from __________ to __________

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State of Incorporation)	(I.R.S. Employer Identification No.)

5555 San Felipe Road, Houston, TX 77056-2723
(Address of principal executive offices)
(713) 629-6600
(Registrant s telephone number)

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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ **Accelerated filer** o **Non-accelerated filer** o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

There were 351,520,042 shares of Marathon Oil Corporation common stock outstanding as of October 31, 2006.

MARATHON OIL CORPORATION
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Quarter Ended September 30, 2006
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Unless the context otherwise indicates, references in this Form 10-Q to Marathon, we, our, or us are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon exerts significant influence by virtue of its ownership interest, typically between 20 and 50 percent).

Effective September 1, 2005, Marathon Ashland Petroleum LLC changed its name to Marathon Petroleum Company LLC. In this Form 10-Q, references to Marathon Petroleum Company LLC (MPC) are references to the entity formerly known as Marathon Ashland Petroleum LLC.

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Part I Financial Information
Item 1. Financial Statements

MARATHON OIL CORPORATION
Consolidated Statements of Income (Unaudited)

(Dollars in millions, except per share data)	Third Quarter Ended September 30, 2006	Third Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$ 15,837	$ 13,248	$ 44,699	$ 35,044
Revenues from matching buy/sell transactions	237	3,433	5,249	9,807
Sales to related parties	418	396	1,141	1,047
Income from equity method investments	109	69	298	153
Net gains on disposal of assets	12	12	28	46
Other income (loss)	21	(7)	48	33
Total revenues and other income	16,634	17,151	51,463	46,130
Costs and expenses:				
Cost of revenues (excludes items below)	11,260	10,825	32,647	27,761
Purchases related to matching buy/sell transactions	222	3,038	5,205	9,312
Purchases from related parties	61	44	159	163
Consumer excise taxes	1,297	1,217	3,739	3,511
Depreciation, depletion and amortization	361	319	1,130	950
Selling, general and administrative expenses	300	324	895	851
Other taxes	92	84	280	241
Exploration expenses	97	64	234	130
Total costs and expenses	13,690	15,915	44,289	42,919
Income from operations	2,944	1,236	7,174	3,211
Net interest and other financing costs (income)	(7)	31	7	99
Minority interests in income (loss) of:				
Marathon Petroleum Company LLC				384
Equatorial Guinea LNG Holdings Limited	(2)	(3)	(7)	(4)
Income from continuing operations before income taxes	2,953	1,208	7,174	2,732
Provision for income taxes	1,330	458	3,296	991
Income from continuing operations	1,623	750	3,878	1,741
Discontinued operations		20	277	26
Net income	$ 1,623	$ 770	$ 4,155	$ 1,767
Per Share Data				
Basic:				
Income from continuing operations	$ 4.55	$ 2.05	$ 10.75	$ 4.94

Discontinued operations			$	0.06	$	0.77	$	0.07
Net income	$	4.55	$	2.11	$	11.52	$	5.01
Diluted:								
Income from continuing operations	$	4.52	$	2.03	$	10.66	$	4.90
Discontinued operations			$	0.06	$	0.76	$	0.07
Net income	$	4.52	$	2.09	$	11.42	$	4.97
Dividends paid	$	0.40	$	0.33	$	1.13	$	0.89

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(Dollars in millions, except per share data)	September 30, 2006	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 2,797	$ 2,617
Receivables, less allowance for doubtful accounts of $3 and $3	3,877	3,476
Receivables from United States Steel	20	20
Receivables from related parties	53	38
Inventories	4,039	3,041
Other current assets	160	191
Total current assets	10,946	9,383
Investments and long-term receivables, less allowance for doubtful accounts of $9 and $10	1,921	1,864
Receivables from United States Steel	507	532
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $13,238 and $12,384	15,806	15,011
Goodwill	1,286	1,307
Intangible assets, less accumulated amortization of $70 and $58	236	200
Other noncurrent assets	127	201
Total assets	$ 30,829	$ 28,498
Liabilities		
Current liabilities:		
Accounts payable	$ 5,619	$ 5,353
Consideration payable under Libya re-entry agreement	212	732
Payables to related parties	230	82
Payroll and benefits payable	297	344
Accrued taxes	830	782
Deferred income taxes	457	450
Accrued interest	51	96
Payable to United States Steel	35	
Long-term debt due within one year	460	315
Total current liabilities	8,191	8,154
Long-term debt	3,230	3,698
Deferred income taxes	2,124	2,030
Employee benefits obligations	1,208	1,321
Asset retirement obligations	763	711
Payable to United States Steel	5	6
Deferred credits and other liabilities	357	438

Total liabilities	15,878	16,358
Minority interests in Equatorial Guinea LNG Holdings Limited	499	435
Commitments and contingencies		
Stockholders Equity		
Common stock issued 367,851,558 and 366,925,852 shares (par value $1 per share, 550,000,000 shares authorized)	368	367
Common stock held in treasury, at cost 14,042,202 and 179,977 shares	(1,111)	(8)
Additional paid-in capital	5,154	5,111
Retained earnings	10,153	6,406
Accumulated other comprehensive loss	(112)	(151)
Unearned compensation		(20)
Total stockholders equity	14,452	11,705
Total liabilities and stockholders equity	$ 30,829	$ 28,498

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

(Dollars in millions)	Nine Months Ended September 30, 2006	2005
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$ 4,155	$ 1,767
Adjustments to reconcile to net cash provided from operating activities:		
Income from discontinued operations	(277)	(26)
Deferred income taxes	186	(80)
Minority interests in income (loss) of subsidiaries	(7)	380
Depreciation, depletion and amortization	1,130	950
Pension and other postretirement benefits, net	(103)	60
Exploratory dry well costs and unproved property impairments	119	64
Net gains on disposal of assets	(28)	(46)
Equity method investments, net	(210)	(18)
Changes in the fair value of long-term U.K. natural gas contracts	(182)	306
Changes in:		
Current receivables	(444)	(1,563)
Inventories	(999)	(456)
Current accounts payable and accrued expenses	334	699
All other, net	2	(147)
Net cash provided from continuing operations	3,676	1,890
Net cash provided from discontinued operations	69	83
Net cash provided from operating activities	3,745	1,973
Investing activities:		
Capital expenditures	(2,405)	(1,952)
Acquisitions	(543)	(506)
Disposal of discontinued operations	832	
Proceeds from sale of minority interests in Equatorial Guinea LNG Holdings Limited		163
Disposal of assets	79	99
Investments loans and advances	(4)	(41)
repayments of loans and advances	219	6
Investing activities of discontinued operations	(45)	(73)
All other, net	15	(7)
Net cash used in investing activities	(1,852)	(2,311)
Financing activities:		
Commercial paper issued, net		285
Payment of debt assumed in acquisition		(1,920)
Other debt repayments	(304)	(7)
Issuance of common stock	41	77

Purchases of common stock	(1,146)	
Excess tax benefits from stock-based compensation arrangements	26	
Dividends paid	(407)	(314)
Distributions to minority shareholder of Marathon Petroleum Company LLC		(272)
Contributions from minority shareholders of Equatorial Guinea LNG Holdings Limited	64	175
Net cash used in financing activities	(1,726)	(1,976)
Effect of exchange rate changes on cash:		
Continuing operations	12	(12)
Discontinued operations	1	
Net increase in cash and cash equivalents	180	(2,326)
Cash and cash equivalents at beginning of period	2,617	3,369
Cash and cash equivalents at end of period	$ 2,797	$ 1,043

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary for a fair presentation of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission (SEC) and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements. Certain reclassifications of prior year data have been made to conform to 2006 classifications. These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the 2005 Annual Report on Form 10-K of Marathon Oil Corporation (Marathon or the Company).

2. New Accounting Standards

EITF Issue No. 04-13

In September 2005, the Financial Accounting Standards Board (FASB) ratified the consensus reached by the Emerging Issues Task Force (EITF) on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The consensus establishes the circumstances under which two or more inventory purchase and sale transactions with the same counterparty should be recognized at fair value or viewed as a single exchange transaction subject to Accounting Principles Board (APB) Opinion No. 29, Accounting for Nonmonetary Transactions. In general, two or more transactions with the same counterparty must be combined for purposes of applying APB Opinion No. 29 if they are entered into in contemplation of each other. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw materials, work-in-process or finished goods.

Effective April 1, 2006, Marathon adopted the provisions of EITF Issue No. 04-13 prospectively. EITF Issue No. 04-13 changes the accounting for matching buy/sell arrangements that are entered into or modified on or after April 1, 2006 (except for those accounted for as derivative instruments, which are discussed below). In a typical matching buy/sell transaction, Marathon enters into a contract to sell a particular quantity and quality of crude oil or refined petroleum products at a specified location and date to a particular counterparty and simultaneously agrees to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. Prior to adoption of EITF Issue No. 04-13, Marathon recorded such matching buy/sell transactions in both revenues and cost of revenues as separate sale and purchase transactions. Upon adoption, these transactions are accounted for as exchanges of inventory.

The scope of EITF Issue No. 04-13 excludes matching buy/sell arrangements that are accounted for as derivative instruments. A portion of Marathon s matching buy/sell transactions are nontraditional derivative instruments, which are contracts involving the purchase or sale of commodities that either do not qualify or have not been designated as normal purchases or normal sales and therefore are required to be accounted for as derivative instruments. Although the accounting for nontraditional derivative instruments is outside the scope of EITF Issue No. 04-13, the conclusions reached in that consensus caused Marathon to reconsider the guidance in EITF Issue No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in Issue No. 02-3. As a result, effective for contracts entered into or modified on or after April 1, 2006, the income effects of matching buy/sell arrangements accounted for as nontraditional derivative instruments are recognized on a net basis as cost of revenues. Prior to this change, Marathon recorded these transactions in both revenues and cost of revenues as separate sale and purchase transactions. This change in accounting principle is being applied on a prospective basis because it is impracticable to apply the change on a retrospective basis.

Transactions arising from all matching buy/sell arrangements entered into before April 1, 2006 will continue to be reported as separate sale and purchase transactions.

The adoption of EITF Issue No. 04-13 and the change in the accounting for nontraditional derivative instruments had no effect on net income. The amounts of revenues and cost of revenues recognized after April 1, 2006 will be less than the amounts that would have been recognized under previous accounting practices.

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SFAS No. 123 (Revised 2004)

In December 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004), Share-Based Payment, (SFAS No. 123(R)) as a revision of SFAS No. 123, Accounting for Stock-Based Compensation. This statement requires entities to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the grant date. That cost is recognized over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. In addition, awards classified as liabilities are remeasured at fair value each reporting period. Marathon had previously adopted the fair value method under SFAS No. 123 for grants made, modified or settled on or after January 1, 2003. Marathon adopted SFAS No. 123(R) as of January 1, 2006, for all awards granted, modified or cancelled after adoption, and for the unvested portion of awards outstanding at January 1, 2006. At the date of adoption, SFAS No. 123(R) requires that an assumed forfeiture rate be applied to any unvested awards and that awards classified as liabilities be measured at fair value. Prior to adopting SFAS No. 123(R), Marathon recognized forfeitures as they occurred and applied the intrinsic value method to awards classified as liabilities. The adoption did not have a significant effect on Marathon s consolidated results of operations, financial position or cash flows.

SFAS No. 123(R) also requires a company to calculate the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to adopting the statement. In November 2005, the FASB issued FASB Staff Position No. 123R-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, to provide an alternative transition election (the short-cut method) to account for the tax effects of share-based payment awards to employees. Marathon elected the long-form method to determine its pool of excess tax benefits as of January 1, 2006.

See Note 3 to the consolidated financial statements for the disclosures regarding share-based payments required by SFAS No. 123(R).

SFAS No. 151

Effective January 1, 2006, Marathon adopted SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4. This statement requires that items such as idle facility expense, excessive spoilage, double freight and re-handling costs be recognized as a current-period charge. The adoption did not have a significant effect on Marathon s consolidated results of operations, financial position or cash flows.

SFAS No. 154

Effective January 1, 2006, Marathon adopted SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires companies to recognize (1) voluntary changes in accounting principle and (2) changes required by a new accounting pronouncement, when the pronouncement does not include specific transition provisions, retrospectively to prior periods financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change.

3. Stock-Based Compensation Arrangements

Description of the Plans

The Marathon Oil Corporation 2003 Incentive Compensation Plan (the Plan) authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards, cash awards and performance awards to employees. The Plan also allows Marathon to provide equity compensation to its non-employee directors. No more than 20,000,000 shares of common stock may be issued under the Plan, and no more than 8,500,000 of those shares may be used for awards other than stock options or stock appreciation rights. Shares subject to awards that are forfeited, terminated, settled in cash, exchanged for other awards, tendered to satisfy the purchase price of an award or withheld to satisfy tax obligations or that expire unexercised or otherwise lapse become available for future grants. Shares issued as a result of awards granted under the Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

The Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (collectively, the Prior Plans). No new grants will be made from the Prior Plans. Any awards previously granted under the Prior Plans shall continue to vest and/or be exercisable in accordance with their original terms and conditions.

Stock-Based Awards under the Plan

Stock options Marathon grants stock options under the Plan. Marathon s stock options represent the right to purchase shares of common stock at the fair market value of the common stock on the date of grant. Through 2004, certain options were granted with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash and/or common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the Plan, over the option price of the shares. Most stock options granted under the Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights (SARs) Prior to 2005, Marathon granted SARs under the Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs that have been granted under the Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock-based performance awards In 2003 and 2004, the Compensation Committee granted stock-based performance awards to certain officers of Marathon and its consolidated subsidiaries under the Plan. Since that time, stock-based performance awards have been replaced with cash-settled performance units for officers. The stock-based performance awards represent shares of common stock that are subject to forfeiture provisions and restrictions on transfer. Those restrictions may be removed if certain pre-established performance measures are met. The stock-based performance awards granted under the Plan will generally vest at the end of a 36-month performance period to the extent that the performance targets are achieved and the recipient is employed by Marathon on that date. Additional shares could be granted at the end of this performance period should performance exceed the targets. Prior to vesting, the recipients have the right to vote and receive dividends on the target number of shares awarded. However, the shares are not transferable until after they vest.

Restricted stock Marathon grants restricted stock and restricted stock units under the Plan. Beginning in 2005, the Compensation Committee has granted time-based restricted stock to officers annually. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient s continued employment. Marathon also grants restricted stock to certain non-officer employees and restricted stock units to certain international non-officer employees (together with the restricted stock granted to officers above, restricted stock awards) based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient s continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by the Company s transfer agent.

Common stock units Marathon maintains an equity compensation program for its non-employee directors under the Plan. All non-employee directors other than the Chairman receive annual grants of common stock units under the Plan and they are required to hold those units until they leave the Board of Directors. When dividends are paid on Marathon common stock, directors receive dividend equivalents in the form of additional common stock units. Prior to January 1, 2006, non-employee directors had the opportunity to receive a matching grant of up to 1,000 shares of common stock if they purchased an equivalent number of shares within 60 days of joining the Board.

Stock-Based Compensation Expense

The fair values of stock options, stock options with tandem SARs and stock-settled SARs (stock option awards) are estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management s best estimates at the time of grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of Marathon s stock price have the most significant impact on the fair value calculation. Marathon has utilized historical data and analyzed current information which reasonably support these assumptions.

The fair values of Marathon s restricted stock awards and common stock units are determined based on the fair market value of the Company s common stock on the date of grant. Prior to adoption of SFAS No. 123(R) on January 1, 2006, the fair values of Marathon s stock-based performance awards were determined in the same manner as restricted stock awards. Under SFAS No. 123(R), on a prospective basis, these awards are required to be valued utilizing an option pricing model. No stock-based performance awards have been granted since May 2004.

Effective January 1, 2006, Marathon s stock-based compensation expense is recognized based on management s best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Unearned stock-based compensation is

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charged to stockholders equity when restricted stock awards and stock-based performance awards are granted. Compensation expense is recognized over the balance of the vesting period and is adjusted if conditions of the restricted stock award or stock-based performance award are not met. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

Prior to January 1, 2006, Marathon recorded stock-based compensation expense over the stated vesting period for stock option awards that are subject to specific vesting conditions and specify (1) that an employee vests in the award upon becoming retirement eligible or (2) that the employee will continue to vest in the award after retirement without providing any additional service. Under SFAS No. 123(R), from the January 1, 2006 date of adoption, such compensation cost is recognized immediately for awards granted to retirement-eligible employees or over the period from the grant date to the retirement eligibility date if retirement eligibility will be reached during the stated vesting period. Stock compensation expense for the first nine months of 2006 included $4 million for such option awards.

During the quarters ended September 30, 2006 and 2005, total employee stock-based compensation expense was $13 million and $43 million. The total related income tax benefits were $4 million and $15 million. During the third quarter of 2006, cash received upon exercise of stock option awards was $22 million. Tax benefits realized for deductions during the third quarter of 2006 that were in excess of the stock-based compensation expense recorded for options exercised and other stock-based awards vested during the quarter totaled $13 million.

During the nine months ended September 30, 2006 and 2005, total employee stock-based compensation expense was $63 million and $106 million. The total related income tax benefits were $23 million and $37 million. In the first nine months of 2006, cash received upon exercise of stock option awards was $41 million. Tax benefits realized for deductions during the nine months ended September 30, 2006 that were in excess of the stock-based compensation expense recorded for options exercised and other stock-based awards vested during the period totaled $27 million.

Cash settlements of stock option awards totaled less than $1 million during the quarter and nine months ended September 30, 2006.

Stock Option Awards Granted

During the nine months ended September 30, 2006 and 2005, Marathon granted stock option awards to both officer and non-officer employees. The weighted average grant date fair values of these awards were based on the following Black-Scholes assumptions:

	Nine Months Ended September 30,	
	2006	2005
Weighted average exercise price per share	$ 75.68	$ 50.28
Expected annual dividends per share	$ 1.60	$ 1.32
Expected life in years	5.1	5.5
Expected volatility	28%	28%
Risk-free interest rate	5.0%	3.8%
Weighted average grant date fair value of stock option awards granted	$ 20.37	$ 12.30

Outstanding Stock-Based Awards

The following is a summary of stock option award activity for the nine months ended September 30, 2006:

	Number of Shares	Weighted-Average Exercise Price

Outstanding at December 31, 2005	6,007,954	$ 36.51
Granted	1,601,800	$ 75.68
Exercised	(1,658,618)	$ 23.60
Canceled	(73,312)	$ 50.67
Outstanding at September 30, 2006 [(a)]	5,877,824	$ 48.49

(a) Of the stock option awards outstanding as of September 30, 2006, 5,383,147 and 494,677 were outstanding under the 2003 Incentive Compensation Plan and 1990 Stock Plan, including 527,625 stock options with tandem SARs.

The intrinsic value of stock option awards exercised during the nine months ended September 30, 2006 and 2005 was $87 million and $94 million. Of those amounts, $30 million in the nine months ended September 30, 2006, and $60 million in the nine months ended September 30, 2005, was related to stock options with tandem SARs.

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The following table presents information on stock option awards at September 30, 2006:

		Outstanding			Exercisable	
Range of Exercise Prices		Number of Shares Under Option	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number of Shares Under Option	Weighted-Average Exercise Price
$25.50	26.91	646,315	6	$ 25.53	646,315	$ 25.53
$28.12	30.88	244,410	5	$ 28.48	239,410	$ 28.43
$32.52	34.00	1,754,300	7	$ 33.50	1,104,724	$ 33.44
$47.65	51.67	1,642,299	9	$ 50.17	442,646	$ 49.91
$75.64	81.02	1,590,500	10	$ 75.68		
Total		5,877,824	8	$ 48.49	2,433,095	$ 33.84

As of September 30, 2006, the aggregate intrinsic value of stock option awards outstanding was $167 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $105 million and 7 years. As of September 30, 2006, the number of fully-vested stock option awards and stock option awards expected to vest was 5,442,968. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $47.56 and 8 years and the aggregate intrinsic value was $160 million. As of September 30, 2006, unrecognized compensation cost related to stock option awards was $36 million, which is expected to be recognized over a weighted average period of 2 years.

The following is a summary of stock-based performance award and restricted stock award activity for the nine months ended September 30, 2006:

	Stock-Based Performance Awards	Weighted Average Grant Date Fair Value	Restricted Stock Awards	Weighted Average Grant Date Fair Value
Unvested at December 31, 2005	448,600	$ 29.93	985,556	$ 47.94
Granted	67,848(a)	$ 76.82	173,610	$ 79.63
Vested	(273,448)	$ 38.30	(204,959)	$ 39.70
Forfeited	(6,000)	$ 33.61	(31,383)	$ 51.68
Unvested at September 30, 2006	237,000	$ 33.61	922,824	$ 55.65

(a) Additional shares were issued in 2006 because the performance targets were exceeded for the 36-month

performance
period related to
the 2003 grant.

During the nine months ended September 30, 2006 and 2005, the weighted average grant date fair value of restricted stock awards was $79.63 and $47.61. The vesting date fair value of stock performance awards which vested during the nine months ended September 30, 2006 and 2005 was $21 million and $5 million. The vesting date fair value of restricted stock awards which vested during the nine months ended September 30, 2006 and 2005 was $16 million and $10 million.

As of September 30, 2006, there was $28 million of unrecognized compensation cost related to stock-based performance awards and restricted stock awards which is expected to be recognized over a weighted average period of 2 years.

4. Discontinued Operations

On June 2, 2006, Marathon sold its Russian oil exploration and production businesses in the Khanty-Mansiysk region of western Siberia. Under the terms of the agreement, Marathon received $787 million for these businesses, plus preliminary working capital and other closing adjustments of $56 million, for a total transaction value of $843 million. Proceeds net of transaction costs and cash held by the Russian businesses at the transaction date totaled $832 million. A gain on the sale of $243 million ($342 million before income taxes) was reported in discontinued operations in the nine months ended September 30, 2006. Income taxes on this gain were reduced by the utilization of a capital loss carryforward as discussed in Note 8 to the consolidated financial statements. Exploration and Production segment goodwill of $21 million was allocated to the Russian assets and reduced the reported gain. The final adjustment to the sales price, if any, is expected to be made before March 31, 2007 and could affect the reported gain.

The activities of the Russian businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Revenues applicable to discontinued operations were $96 million for the third quarter of 2005 and totaled $173 million and $226 million for the nine months ended September 30, 2006 and 2005. Pretax income from discontinued operations was $32 million for the third quarter of 2005 and was $45 million and $39 million for the nine months ended September 30, 2006 and 2005. There were no amounts recorded in the third quarter of 2006 related to discontinued operations.

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5. Computation of Income per Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options, provided the effect is not antidilutive.

	Third Quarter Ended September 30,			
	2006		2005	
(Dollars in millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,623	$ 1,623	$ 750	$ 750
Discontinued operations			20	20
Net income	$ 1,623	$ 1,623	$ 770	$ 770
Shares of common stock outstanding (thousands):				
Average number of common shares outstanding	356,330	356,330	365,137	365,137
Effect of dilutive securities		3,038		3,427
Average common shares including dilutive effect	356,330	359,368	365,137	368,564
Per share:				
Income from continuing operations	$ 4.55	$ 4.52	$ 2.05	$ 2.03
Discontinued operations	$	$	$ 0.06	$ 0.06
Net income	$ 4.55	$ 4.52	$ 2.11	$ 2.09

	Nine Months Ended September 30,			
	2006		2005	
(Dollars in millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 3,878	$ 3,878	$ 1,741	$ 1,741
Discontinued operations	277	277	26	26
Net income	$ 4,155	$ 4,155	$ 1,767	$ 1,767
Shares of common stock outstanding (thousands):				
Average number of common shares outstanding	360,710	360,710	352,807	352,807
Effect of dilutive securities		3,228		2,919
Average common shares including dilutive effect	360,710	363,938	352,807	355,726
Per share:				
Income from continuing operations	$ 10.75	$ 10.66	$ 4.94	$ 4.90
Discontinued operations	$ 0.77	$ 0.76	$ 0.07	$ 0.07
Net income	$ 11.52	$ 11.42	$ 5.01	$ 4.97

The per share calculations for the third quarter and nine months ended September 30, 2006 above exclude 1 million stock options, as they were antidilutive.

6. Segment Information

Marathon s operations consist of three reportable operating segments:

1) Exploration and Production (E&P) explores for, produces and markets crude oil and natural gas on a worldwide basis;

2)

Refining, Marketing and Transportation (RM&T) refines, markets and transports crude oil and petroleum products, primarily in the Midwest, the upper Great Plains and southeastern United States; and

3) Integrated Gas (IG) markets and transports products manufactured from natural gas, such as liquefied natural gas (LNG) and methanol, on a worldwide basis, and is developing other projects to link stranded natural gas resources with key demand areas.

Effective January 1, 2006, Marathon revised its measure of segment income to include the effects of minority interests and income taxes related to the segments to facilitate comparison of segment results with Marathon s peers. Income taxes are allocated to the segments using estimated effective rates for each segment. In addition, the results of activities primarily associated with the marketing of the Company s equity natural gas production, which had been presented as part of the Integrated Gas segment prior to 2006, are now included in the Exploration and Production segment as those activities are aligned with E&P operations. Segment information for all periods presented reflects these changes.

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As discussed in Note 4, the Russian businesses that were sold in June 2006 have been accounted for as discontinued operations. Segment information for all presented periods excludes the amounts for these Russian operations.

(Dollars in millions)	E&P	RM&T	IG	Total Segments
Third Quarter Ended September 30, 2006				
Revenues:				
Customer	$ 2,062	$ 13,861	$ 30	$ 15,953
Intersegment[(a)]	200	1		201
Related parties	3	415		418
Segment revenues	2,265	14,277	30	16,572
Elimination of intersegment revenues	(200)	(1)		(201)
Gain on long-term U.K. natural gas contracts	121			121
Total revenues	$ 2,186	$ 14,276	$ 30	$ 16,492
Segment income (loss)	$ 572	$ 1,026	$ (2)	$ 1,596
Income from equity method investments	57	48	4	109
Depreciation, depletion and amortization [(b)]	209	142	3	354
Minority interests in loss of subsidiaries			(2)	(2)
Provision for income taxes [(b)]	644	656	7	1,307
Capital expenditures [(c)]	795	223	72	1,090

(Dollars in millions)	E&P	RM&T	IG	Total Segments
Third Quarter Ended September 30, 2005				
Revenues:				
Customer	$ 1,682	$ 14,989	$ 92	$ 16,763
Intersegment[(a)]	150	78		228
Related parties	3	393		396
Segment revenues	1,835	15,460	92	17,387
Elimination of intersegment revenues	(150)	(78)		(228)
Loss on long-term U.K. natural gas contracts	(82)			(82)
Total revenues	$ 1,603	$ 15,382	$ 92	$ 17,077
Segment income	$ 373	$ 473	$ 22	$ 868
Income from equity method investments	15	38	16	69
Depreciation, depletion and amortization [(b)]	185	123	2	310
Minority interests in loss of subsidiaries			(3)	(3)
Provision for income taxes [(b)]	201	340	(4)	537
Capital expenditures [(c)]	361	206	205	772

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(Dollars in millions)	E&P	RM&T	IG	Total Segments
Nine Months Ended September 30, 2006				
Revenues:				
Customer	$ 6,495	$ 43,141	$ 130	$ 49,766
Intersegment [a]	577	16		593
Related parties	9	1,132		1,141
Segment revenues	7,081	44,289	130	51,500
Elimination of intersegment revenues	(577)	(16)		(593)
Gain on long-term U.K. natural gas contracts	182			182
Total revenues	$ 6,686	$ 44,273	$ 130	$ 51,089
Segment income	$ 1,696	$ 2,262	$ 23	$ 3,981
Income from equity method investments	163	106	29	298
Depreciation, depletion and amortization [b]	686	412	7	1,105
Minority interests in loss of subsidiaries			(7)	(7)
Provision for income taxes [b]	1,840	1,424	11	3,275
Capital expenditures [c]	1,616	527	236	2,379

(Dollars in millions)	E&P	RM&T	IG	Total Segments
Nine Months Ended September 30, 2005				
Revenues:				
Customer	$ 5,021	$ 39,939	$ 197	$ 45,157
Intersegment [a]	425	161		586
Related parties	8	1,039		1,047
Segment revenues	5,454	41,139	197	46,790
Elimination of intersegment revenues	(425)	(161)		(586)
Loss on long-term U.K. natural gas contracts	(306)			(306)
Total revenues	$ 4,723	$ 40,978	$ 197	$ 45,898
Segment income	$ 1,211	$ 863	$ 44	$ 2,118
Income from equity method investments	37	71	45	153
Depreciation, depletion and amortization [b]	588	332	6	926
Minority interests in income (loss) of subsidiaries [b]		376	(4)	372
Provision for income taxes [b]	685	606	(5)	1,286
Capital expenditures [c]	927	508	513	1,948

(a) Management believes intersegment

transactions were conducted under terms comparable to those with unrelated parties.

(b) Differences between segment totals and Marathon totals represent amounts related to corporate administrative activities and other unallocated items and are included in Items not allocated to segments, net of income taxes in the reconciliation below.

(c) Differences between segment totals and Marathon totals represent amounts related to corporate administrative activities.

The following reconciles segment income to net income as reported in Marathon s consolidated statements of income:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2006	2005	2006	2005
Segment income	$ 1,596	$ 868	$ 3,981	$ 2,118
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(52)	(91)	(217)	(235)
Gain (loss) on long-term U.K. natural gas contracts	58	(48)	93	(178)
Gain on sale of minority interests in EG Holdings		21		21
Ohio tax legislation				15
U.K. tax legislation	21		21	

Discontinued operations		20	277	26
Net income	$ 1,623	$ 770	$ 4,155	$ 1,767

7. Pensions and Other Postretirement Benefits

The following summarizes the components of net periodic benefit cost:

	Third Quarter Ended September 30,			
	Pension Benefits		Other Benefits	
(Dollars in millions)	2006	2005	2006	2005
Service cost	$ 33	$ 31	$ 6	$ 5
Interest cost	33	30	10	10
Expected return on plan assets	(30)	(24)		
Amortization:				
net transition gain		(1)		
prior service costs (credits)	2	1	(3)	(3)
actuarial loss	9	12	3	2
Multi-employer and other plans		1		1
Net periodic benefit cost	$ 47	$ 50	$ 16	$ 15

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(Dollars in millions)	2006	2005	2006	2005
Service cost	$ 99	$ 88	$ 18	$ 14
Interest cost	96	88	31	29
Expected return on plan assets	(85)	(70)		
Amortization:				
net transition gain		(3)		
prior service costs (credits)	4	3	(9)	(9)
actuarial loss	33	42	7	7
Multi-employer and other plans	1	2	2	2
Net periodic benefit cost	$ 148	$ 150	$ 49	$ 43

During the nine months ended September 30, 2006, Marathon made contributions of $274 million to its funded pension plans. Of this amount, $21 million related to foreign pension plans. Marathon currently estimates additional contributions of $350 million over the remainder of 2006. Contributions made from the general assets of Marathon to cover current benefit payments related to unfunded pension and other postretirement benefit plans were $3 million and $24 million for the first nine months of 2006.

8. Income Taxes

The provision for income taxes for interim periods is based on management s best estimate of the effective income tax rate expected to be applicable for the current year plus any adjustments arising from a change in the estimated amount of taxes related to prior periods. The following is an analysis of the effective income tax rates for continuing operations for the periods presented:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005

Statutory U.S. income tax rate	35.0%	35.0%	35.0%	35.0%
Effects of foreign operations	9.2	(0.9)	9.9	(0.8)
State and local income taxes after federal income tax effects	2.9	3.6	2.3	2.4
Other tax effects	(2.1)	0.2	(1.3)	(0.3)
Effective income tax rate for continuing operations	45.0%	37.9%	45.9%	36.3%

In July 2006, the U.K. supplemental corporation tax rate was increased from 10 percent to 20 percent effective January 1, 2006. The provision for income taxes for the third quarter of 2006 includes a charge of $26 million, representing the impact of the rate increase on the applicable earnings for the first six months of 2006, and a credit of $21 million, representing the impact of the rate increase on the applicable net deferred tax assets recorded as of January 1, 2006.

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Capital loss carryforwards were utilized in conjunction with the sale of Marathon s Russian oil exploration and production businesses in June 2006, as discussed in Note 4 to the consolidated financial statements. The reversal of the valuation allowance reduced income taxes attributable to discontinued operations by $79 million. The sale of the Russian businesses fully utilized the Company s deferred tax asset related to capital loss carryforwards.

Marathon is continuously undergoing examination of its federal income tax returns by the Internal Revenue Service. Audits of the Company s 1998 through 2001 income tax returns have been completed and agreed upon by all parties. A $46 million refund is expected from the 1998 through 2001 audits, $35 million of which is payable to United States Steel in accordance with the tax sharing agreement between Marathon and United States Steel. See Note 3 to the consolidated financial statements, Information about United States Steel, in Marathon s 2005 Annual Report on Form 10-K for discussion of this tax sharing agreement. Audits of the Company s 2002 and 2003 income tax returns have been agreed upon by Marathon and the Internal Revenue Service and have been sent to the Joint Committee on Taxation for approval. Audits for tax years 2004 and 2005 commenced in May 2006. Marathon believes it has made adequate provision for federal income taxes and interest which may become payable for years not yet settled.

9. Comprehensive Income

The following sets forth Marathon s comprehensive income for the periods indicated:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2006	2005	2006	2005
Net income	$ 1,623	$ 770	$ 4,155	$ 1,767
Other comprehensive income (loss), net of taxes:				
Minimum pension liability adjustments	23		38	24
Change in fair value of derivative instruments	(3)	(1)	1	(16)
Total comprehensive income	$ 1,643	$ 769	$ 4,194	$ 1,775

10. Inventories

Inventories are carried at the lower of cost or market. The cost of inventories of crude oil, refined products and merchandise is determined primarily under the last-in, first-out (LIFO) method.

(Dollars in millions)	September 30, 2006	December 31, 2005
Liquid hydrocarbons and natural gas	$ 1,931	$ 1,093
Refined products and merchandise	1,920	1,763
Supplies and sundry items	188	185
Total, at cost	$ 4,039	$ 3,041

11. Property, Plant and Equipment

Exploratory well costs capitalized greater than one year after completion of drilling as of September 30, 2006 were $89 million. In the first quarter of 2006, $40 million of costs were added to this category for wells in Equatorial Guinea (Corona, Bococo and Gardenia) where Marathon has been evaluating various development scenarios for the discoveries around the Alba Field, including plans that would integrate the resources into the Company s long-term LNG supply. In the third quarter of 2006, $10 million of costs capitalized for more than one year related to the Bococo well were written off when Marathon made the decision to relinquish the related acreage.

12. Long-term Debt

Effective May 4, 2006, Marathon entered into an amendment to its $1.5 billion five-year revolving credit agreement, expanding the size of the facility to $2.0 billion and extending the termination date from May 2009 to May 2011. Interest on this facility is based on defined short-term market rates. During the term of the agreement, Marathon is obligated to pay a variable facility fee on the total commitment, which at September 30, 2006 was 0.08 percent. At September 30, 2006, there were no borrowings against this facility. Concurrent with this amendment, the $500 million MPC revolving credit agreement was terminated.

13. Commitments and Contingencies

Marathon is the subject of, or party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. Certain of these commitments are discussed below. The ultimate resolution of these contingencies could, individually or in the aggregate, be material to Marathon s consolidated financial statements. However, management believes that Marathon will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably.

Contract commitments At September 30, 2006 and December 31, 2005, Marathon s contract commitments to acquire property, plant and equipment totaled $734 million and $668 million, respectively. The increase during the first nine months of 2006 was primarily related to refining and transportation property, plant and equipment commitments. Partially offsetting this increase were declines related to commitments for the Equatorial Guinea LNG plant, the Neptune development in the Gulf of Mexico and the Alvheim project in Norway where construction continues to progress.

Guarantees In conjunction with the sale of its Russian businesses as discussed in Note 4 to the consolidated financial statements, Marathon guaranteed the purchaser with regard to unknown obligations and inaccuracies in representations, warranties, covenants and agreements by Marathon. These indemnifications are part of the normal course of selling assets. Under the agreement, the maximum potential amount of future payments associated with these guarantees is equivalent to the proceeds from the sale.

14. Stock Repurchase Program

On January 29, 2006, Marathon s Board of Directors authorized the repurchase of up to $2 billion of common stock over a period of two years. Such purchases are to be made during this period as Marathon s financial condition and market conditions warrant. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. The repurchase program does not include specific price targets and is subject to termination prior to completion. Marathon will use cash on hand, cash generated from operations or cash from available borrowings to acquire shares. During the first nine months of 2006, Marathon acquired 14.4 million common shares at an acquisition cost of $1.146 billion, which were recorded as common stock held in treasury in the consolidated balance sheet.

15. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(Dollars in millions)	2006	2005
Net cash provided from operating activities included:		
Interest paid (net of amounts capitalized)	$ 109	$ 167
Income taxes paid to taxing authorities	3,215	917
Noncash investing and financing activities:		
Asset retirement costs capitalized	$ 18	$ 12
Payments of debt assumed by United States Steel	24	8
Disposal of assets:		
Asset retirement obligations assumed by buyer	9	3
Acquisitions:		
Debt and other liabilities assumed	25	5,067
Common stock issued to seller		955
Receivables transferred to seller		913
Commercial paper and revolving credit arrangements, net:		
Borrowings	$ 1,321	$ 3,873

Repayments	(1,321)	(3,588)

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16. MPC Receivables Purchase and Sale Facility

On July 1, 2005, MPC entered into a $200 million, three-year Receivables Purchase and Sale Agreement with certain purchasers. The program was structured to allow MPC to periodically sell a participating interest in pools of eligible accounts receivable. During the term of the agreement MPC was obligated to pay a facility fee of 0.12%. In the first quarter of 2006, the facility was terminated. No receivables were sold under the agreement during its term.

17. Accounting Standards Not Yet Adopted

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106, and 132(R). This standard requires an employer to: (a) recognize in its statement of financial position an asset for a plan s overfunded status or a liability for a plan s underfunded status; (b) measure a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year (with limited exceptions); and (c) recognize changes in the funded status of a plan in the year in which the changes occur through comprehensive income. The funded status of a plan is measured as the difference between plan assets at fair value and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation and for any other postretirement plan it is the accumulated postretirement benefit obligation. Marathon is required to recognize the funded status of its plans and to provide the additional required disclosures in its December 31, 2006 consolidated financial statements. Marathon currently measures the plan assets and benefit obligations of its pension and other postretirement plans as of December 31. Upon adoption, Marathon expects to increase its recorded liabilities for pension and other postretirement benefits by $650 million to $700 million. After related income tax effects, the net decrease in stockholders equity is estimated to be between $400 million and $430 million.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Marathon, SFAS No. 157 will be effective January 1, 2008, with early application permitted. Marathon is currently evaluating the provisions of this statement.

In September 2006, the FASB issued FASB Staff Position (FSP) No. AUG AIR-1, Accounting for Planned Major Maintenance Activities. This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods. Marathon expenses such costs in the same annual period as incurred; however, estimated annual major maintenance costs are recognized as expense throughout the year on a pro rata basis. As such, adoption of FSP No. AUG AIR-1 will have no impact on Marathon s annual consolidated financial statements but will require Marathon to retrospectively adjust its results of operations for prior interim periods because major maintenance costs will no longer be recognized on a pro rata basis throughout the year. Marathon is required to adopt the FSP effective January 1, 2007, but early adoption is permitted. Marathon is currently evaluating the provisions of FSP No. AUG AIR-1 to determine the impact on its interim consolidated financial statements.

In September 2006, the SEC issued SEC Staff Accounting Bulletin (SAB) No. 108, Financial Statements Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 addresses how a registrant should quantify the effect of an error in the financial statements for purposes of assessing materiality and requires that the effect be computed using both the current year income statement perspective (rollover) and the year end balance sheet perspective (iron curtain) methods for fiscal years ending after November 15, 2006. If a change in the method of quantifying errors is required under SAB No. 108, this represents a change in accounting policy; therefore, if the use of both methods results in a larger, material misstatement than the previously applied method, the financial statements must be adjusted. SAB No. 108 allows the cumulative effect of such adjustments to be made to opening retained earnings upon adoption. Marathon does not expect adoption of SAB No. 108 to have an effect on its consolidated results of operations, financial position or cash flows.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. For Marathon, the provisions of FIN No. 48 are effective January 1, 2007. Marathon is currently evaluating the provisions of FIN No. 48 to determine the impact on its consolidated financial statements.

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In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). Included in the scope of this issue are any taxes assessed by a governmental authority that are imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF concluded that the presentation of such taxes on a gross basis (included in revenues and costs) or a net basis (excluded from revenues) is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22. In addition, the amounts of such taxes reported on a gross basis must be disclosed if those tax amounts are significant. For Marathon, the disclosure prescribed by this consensus is required in its 2007 consolidated financial statements but early application is permitted.

In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets An Amendment of FASB Statement No. 140. This statement amends SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, with respect to the accounting for separately recognized servicing assets and servicing liabilities. Marathon is required to adopt SFAS No. 156 effective January 1, 2007. Marathon does not expect adoption of this statement to have a significant effect on its consolidated results of operations, financial position or cash flows.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140. SFAS No. 155 simplifies the accounting for certain hybrid financial instruments, eliminates the interim FASB guidance which provides that beneficial interests in securitized financial assets are not subject to the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and eliminates the restriction on the passive derivative instruments that a qualifying special-purpose entity may hold. For Marathon, SFAS No. 155 is effective for all financial instruments acquired or issued on or after January 1, 2007. Marathon does not expect adoption of this statement to have a significant effect on its consolidated results of operations, financial position or cash flows.

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

Marathon Oil Corporation is engaged in worldwide exploration, production and marketing of crude oil and natural gas; domestic refining, marketing and transportation of crude oil and petroleum products primarily in the Midwest, the upper Great Plains and southeastern United States; and worldwide marketing and transportation of products manufactured from natural gas, such as liquefied natural gas (LNG) and methanol, and development of other projects to link stranded natural gas resources with key demand areas. Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the Consolidated Financial Statements and Selected Notes to Consolidated Financial Statements and the Supplemental Statistics.

Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, plans, projects, could, would or similar words indicating that future outcomes are uncertain. In accordance with safe harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2005 Annual Report on Form 10-K.

We acquired the 38 percent interest in MPC previously held by Ashland Inc. (Ashland) on June 30, 2005. Unless specifically noted as being after minority interests, amounts for the Refining, Marketing and Transportation segment include amounts related to the 38 percent interest held by Ashland prior to June 30, 2005.

Marathon holds a 60 percent interest in Equatorial Guinea LNG Holdings Limited. The remaining interests are held by a company controlled by the government of Equatorial Guinea (25 percent interest), Mitsui & Co., Ltd. (8.5 percent interest) and a subsidiary of Marubeni Corporation (6.5 percent interest). Unless specifically noted as being after minority interests, amounts for the Integrated Gas segment include amounts related to the minority interests.

Overview and Outlook

Exploration and Production (E&P)

Reported liquid hydrocarbon and natural gas sales during the third quarter and the first nine months of 2006 averaged 362,000 barrels of oil equivalent per day (boepd) and 368,000 boepd. We estimate our full year 2006 production available for sale will average between 360,000 and 370,000 boepd. This estimate reflects the impact of the sale of our former Russian oil exploration and production businesses, but excludes the effect of any future acquisitions or dispositions. Reported volumes are based on sales volumes which may vary from production available for sale primarily due to the timing of liftings from certain of our international locations.

In Libya, sales volumes for the third quarter of 2006 exceeded prior quarters as we produced and sold 2.8 million barrels of oil that were owed to our account upon the resumption of our operations in Libya. We expect our Libya production available for sale in the fourth quarter of 2006 to return to the levels experienced in the first half of the year. We continue to work with our partners in Libya to define growth plans for this business. In 2006, the United States restored full diplomatic ties with Libya. A United States embassy has been reopened and Libya has been removed from the list of state sponsors of terrorism.

We continue to advance our major E&P projects. In Norway, the Alvheim project was 73 percent complete as of September 30, 2006, and is on target to deliver first production by the end of the first quarter of 2007. Also in Norway, we submitted a plan of development and operation for the Volund field to the Norwegian government, with a recommendation that it be tied back to the Alvheim floating production, storage and offloading vessel (FPSO). We expect government approval during the fourth quarter of 2006. We own 65 percent interests and serve as operator for both Alvheim and Volund. Progress also continues on the outside-operated Vilje project in Norway, where the flowlines are 97 percent complete. Drilling is expected to commence in the second quarter of 2007 with first production estimated in the third quarter of 2007. We own a 47 percent interest in Vilje. The Neptune development in the Gulf of Mexico was 55 percent complete as of September 30, 2006, and remains on target to deliver first production by early 2008. Development drilling began in the second quarter of 2006. We own a 30 percent outside-operated interest in Neptune.

In the first half of 2006, we completed leasehold acquisitions totaling approximately 200,000 acres in the Bakken Shale resource play. The majority of the acreage is located in North Dakota with the remainder in eastern Montana. We now own a substantial position in the Bakken Shale with approximately 300 locations to be drilled over the next four to five years. Two new wells were completed during the third quarter of 2006.

In July 2006, we completed a leasehold acquisition of a long-life natural gas asset in the Piceance Basin of Colorado, located in Garfield County in the Greater Grand Valley Field Complex. The acreage is flanked by, and on-trend with, adjacent production. Our plans include drilling approximately 700 wells over the next ten years with first production expected in late 2007.

We own an 18.5 percent interest in the outside-operated Corrib natural gas development project, located off the western coast of Ireland. Onshore development activities started in late 2004 but were suspended in 2005 pending resolution of issues raised by opponents of the project. In July 2006, the partners in this project accepted the findings of a government-commissioned independent safety review and the report of an independent mediator regarding the onshore pipeline associated with the proposed development. Construction of the natural gas plant re-commenced in the third quarter of 2006.

In the third quarter of 2006, we announced the Titania discovery in Block 31, offshore Angola, where we own a 10 percent outside-operated interest. Two additional wells in deepwater Angola Block 32, where we own a 30 percent outside-operated interest, reached total depth in the third quarter of 2006 and their results will be reported upon governmental approval. Year to date through September 30, 2006, we have announced five exploration or appraisal discoveries: Mostarda, Urano, Titania and an unnamed discovery in Angola, and Gudrun in Norway. We are currently participating in three wells in deepwater Angola, and are drilling the Blackwater Prospect in deepwater in the Gulf of Mexico. We have a 40 percent interest in the Blackwater Prospect and we are the operator.

In the second quarter of 2006, we were awarded a 70 percent interest and will be the operator in the Pasangkayu Block offshore Indonesia. The 1.2 million acre block is located mostly in deep water, predominantly offshore of the island of Sulawesi in the Makassar Strait, directly east of the Kutei Basin oil and natural gas production region. The production sharing contract with the Indonesian government was signed during the third quarter of 2006. We expect to begin collecting geophysical data in 2007, followed by exploratory drilling in 2008 and 2009.

In the second quarter of 2006, we sold our Russian oil exploration and production businesses. Under the terms of the agreement, we received $787 million for these businesses, plus preliminary working capital and other closing adjustments of $56 million, for a total transaction value of $843 million. A gain on the sale of $243 million ($342 million before tax) is reported in discontinued operations for the nine months ended September 30, 2006. The final adjustment to the sales price, if any, is expected to be made before March 31, 2007 and could affect the reported gain. For all periods presented, the activities of the Russian businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows, and have been excluded from the E&P segment results.

In July 2006, the U.K. supplemental corporation tax rate was increased from 10 percent to 20 percent effective January 1, 2006. Our provision for income taxes for the third quarter of 2006 includes a charge of $26 million, representing the impact of the rate increase on the applicable earnings for the first six months of 2006, and a credit of $21 million, representing the impact of the rate increase on net deferred tax assets recorded as of January 1, 2006. The impact on the January 1, 2006 net deferred tax assets has been excluded from E&P segment income.

In Nova Scotia, we are in discussions with our partners and government officials regarding our future activities on the Cortland lease, where we own a 75 percent interest, and the Empire lease, where we own a 50 percent interest. We serve as operator and have a remaining commitment of approximately $50 million on these leases. We continue to evaluate options for the Annapolis discovery in Nova Scotia. We own a 30 percent interest and serve as operator for Annapolis.

In October 2006, the Syrian government approved the assignment of 90 percent of our interest in the Ash Shaer and Cherrife natural gas fields to a non-U.S. company. We closed the transaction on November 1, 2006, and received cash proceeds of $46 million. The production sharing contract (PSC) between us and the Syrian Petroleum Company that was signed into law in July 2006 gave us the right to sell all or a significant portion of our interest in these fields to a third party, subject to the consent of the Syrian government, and resolved the previous disputes between us and the Syrian Petroleum Company and the government of Syria over our interest in these fields. While we continue to hold a 10 percent outside-operated interest, we have and will continue to comply with all U.S. sanctions related to Syria. We have recognized no revenues in any period from activities in Syria and we impaired our entire investment in Syria in 1998.

We hold an outside-operated interest in an exploration and production license in Sudan and are investigating the disposition of this interest. We suspended operations in Sudan in 1985. We have had no employees in the country and have derived no economic benefit from those interests since that time. We have abided and will continue to abide by all U.S. sanctions related to Sudan and will not consider resuming any activity regarding our interests there until such time as it is permitted under U.S. law.

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Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities. Due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

The above discussion includes forward-looking statements with respect to the timing and levels of our worldwide and Libya liquid hydrocarbon, natural gas and condensate production available for sale, the development of the Alvheim and Vilje fields, approval of the Volund plan of development and operation, the Neptune development, and anticipated future exploratory and development drilling activity. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, amount of capital available for exploration and development, acquisitions or dispositions of oil and natural gas properties, regulatory constraints, timing of commencing production from new wells, drilling rig availability, inability or delay in obtaining necessary government and third-party approvals and permits, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response and other geological, operating and economic considerations. The above discussion also includes a forward-looking statement with respect to the timing of the final adjustment to the purchase price for our former businesses in Russia, which could be affected by the work of experts analyzing the adjustment and on-going negotiations. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Refining, Marketing and Transportation (RM&T)

Our refining and wholesale marketing gross margin averaged 32.71 cents per gallon in the third quarter of 2006, outperforming the relevant market indicators. This performance was driven primarily by our ability to increase refined product sales realizations more than the change in spot market prices.

Our total refinery throughput during the third quarter of 2006 was 4.5 percent higher than the same quarter in 2005. We continue to expect that our 2006 average crude oil throughput will exceed our record throughput for 2005. During the third quarter of 2006, we blended approximately 36 thousand barrels per day (mbpd) of ethanol into gasoline, 6 percent less than we blended in the third quarter of 2005. The expansion or contraction of our ethanol blending program will be driven by the economics of the ethanol supply.

During the third quarter of 2006, Speedway SuperAmerica LLC achieved increased same store merchandise sales of 6.7 percent over the third quarter of 2005, while same store gasoline sales volumes increased 4.9 percent when compared to the third quarter of 2005.

Our board of directors approved an estimated $3.2 billion project that will expand the crude oil refining capacity of our Garyville, Louisiana refinery by 180,000 barrels per day (bpd). This will increase the capacity of the Garyville refinery from 245,000 bpd to 425,000 bpd and our total refining capacity from 974,000 bpd to approximately 1,154,000 bpd. The estimated cost of the expansion has been revised from the original estimate of $2.2 billion primarily due to an increase in engineering and construction costs as both labor and material costs have increased significantly over the last year. The majority of the remaining increase is primarily due to an increase in the processing unit capacities and tankage to help optimize the overall economics of the project. The expansion is subject to obtaining necessary permits from applicable regulatory agencies. We recently completed the FEED cost estimation phase and permitting is underway with the Louisiana Department of Environmental Quality (LDEQ). Upon final permit approval, construction is expected to begin in mid-2007 with startup planned for the fourth quarter of 2009.

We completed our ultra-low sulfur diesel fuel modifications on time and under budget during the second quarter of 2006. Production of ultra-low sulfur diesel fuel began prior to the June 1, 2006 deadline set by U.S. Environmental Protection Agency regulations.

The International Brotherhood of Teamsters labor agreement covering certain hourly employees of our St. Paul Park, Minnesota, refinery expired on May 31, 2006. Contract negotiations commenced in early May, but the union elected to strike on July 19, 2006. On September 5, 2006, an agreement was reached with the union, ending the strike, and the new contract is scheduled to expire on May 31, 2009. We operated the St. Paul Park refinery at normal capacity during the strike. Also in the third quarter of 2006, the labor agreement covering certain hourly employees of our Detroit, Michigan refinery was extended four years to January 31, 2011.

In October 2006, we signed a definitive agreement forming a joint venture to construct and operate one or more ethanol plants. Our partner in the joint venture will provide the day-to-day management of the plants, as well as corn origination, and distillers dried grain and ethanol marketing services. This venture will enable us to maintain the reliability of a portion of our future ethanol supplies.

The above discussion includes forward-looking statements with respect to projections of crude oil throughput, the Garyville expansion project and the joint venture to construct and operate ethanol plants. Some factors that could potentially affect these forward-looking statements include planned and unplanned refinery maintenance projects, the levels of refining margins and other operating considerations, transportation logistics, availability of materials and labor, necessary government and third-party approvals, unforeseen hazards such as weather conditions, and other risks customarily associated with construction projects. The Garyville project may be further affected by crude oil supply. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas (IG)

Our integrated gas activities during the third quarter of 2006 were marked by continued progress in constructing the LNG plant in Equatorial Guinea. The project was approximately 95 percent complete as of September 30, 2006 and is ahead of its original schedule with the first shipments of LNG projected for mid-2007. We own a 60 percent interest in Equatorial Guinea LNG Holdings Limited.

During the third quarter of 2006, the partners in the Equatorial Guinea LNG plant began FEED work for a second LNG train on Bioko Island, Equatorial Guinea, which is expected to be completed by the end of the first quarter of 2007. Key to the final investment decision regarding construction of a second train is securing long-term natural gas supply agreements with the owners of surrounding natural gas resources. Together with our partners, we are in discussions with natural gas resource holders in Equatorial Guinea, Nigeria and Cameroon to secure the necessary gas supplies. Upon securing adequate gas supplies and the completion of the FEED, we expect an investment decision will be made during 2007 or 2008, with LNG deliveries from the second train commencing in 2011 or 2012.

Atlantic Methanol Production Company LLC (AMPCO) experienced 35 days of downtime during the third quarter of 2006 primarily related to compressor problems. Deliveries resumed in October 2006 and AMPCO expects to reach its full expansion capacity during 2007.

The above discussion contains forward-looking statements with respect to the estimated construction and startup dates of a LNG project which could be affected by unforeseen problems arising from construction, inability or delay in obtaining necessary government and third-party approvals, unanticipated changes in market demand or supply, environmental issues, availability or construction of sufficient LNG vessels, and unforeseen hazards such as weather conditions. The above discussion also contains forward-looking statements with respect to the second LNG train which could be affected by partner approvals, results of the FEED work, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. The above discussion also contains forward-looking statements with respect to the timing and levels of future capacity at AMPCO which could be affected by unforeseen problems arising from equipment installation. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Other

In November 2006, we announced plans to issue a request for proposals to engage interested parties in a process that could lead to a Canadian oil sands venture. This process is intended to explore various commercial arrangements under which we would provide heavy Canadian oil sands crude oil processing capacity in exchange for an equity interest in a Canadian oil sands project through a joint venture, or other alternative business arrangements that potential partners may choose to propose. We also awarded a FEED contract for a proposed heavy oil upgrading project at our Detroit, Michigan refinery and will be undertaking a feasibility study for a similar upgrading project at our Catlettsburg, Kentucky refinery. The Detroit FEED work and the Catlettsburg feasibility study are expected to be completed by late 2007. The final investment decision for the Detroit project is subject to completion of the FEED, approval of our board of directors and the receipt of applicable permits. After conclusion of the Catlettsburg feasibility study, a decision will be made whether to move the project to the FEED stage.

The above discussion contains forward-looking statements concerning plans to issue a request for proposals regarding a potential venture, and potential heavy oil refining upgrading projects. Some factors that could potentially affect these forward-looking statements include unforeseen difficulty in negotiation of definitive agreements, completion of the FEED work, inability or delay in obtaining necessary government and third party approvals, continued favorable investment climate and other geological, operating and economic considerations. The refining upgrading projects may be further affected by approval of our board of directors. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Change in Accounting for Matching Buy/Sell Transactions

Matching buy/sell transactions arise from arrangements in which we agree to buy a specified quantity and quality of crude oil or refined petroleum products to be delivered to a specified location while simultaneously agreeing to sell a specified quantity and quality of the same commodity at a specified location to the same counterparty. Prior to April 1, 2006, all matching buy/sell transactions were recorded as separate sale and purchase transactions, or on a gross basis. Effective for contracts entered into or modified on or after April 1, 2006, the income effects of matching buy/sell transactions are reported in cost of revenues, or on a net basis. Transactions under contracts entered into before April 1, 2006 will continue to be reported on a gross basis.

Each purchase and sale transaction has the characteristics of a separate legal transaction, including separate invoicing and cash settlement. Accordingly, we believed that we were required to account for these transactions separately. A recent accounting interpretation clarified the circumstances under which a matching buy/sell transaction should be viewed as a single transaction for the exchange of inventory. For a further description of the accounting requirements and how they apply to matching buy/sell transactions, see Note 2 to the consolidated financial statements, New Accounting Standards.

This accounting change had no effect on net income. The amounts of revenues and cost of revenues recognized after April 1, 2006 will be less than the amounts that would have been recognized under previous accounting practices.

Additionally, this accounting change will affect the comparability of certain operating statistics, most notably refining and wholesale marketing gross margin per gallon. While this change will not have a significant effect on the refining and wholesale marketing gross margin (the numerator for calculating this statistic), sales volumes (the denominator for calculating this statistic) recognized after April 1, 2006 will be less than the amount that would have been recognized under previous accounting practices because volumes related to matching buy/sell transactions under contracts entered into or modified on or after April 1, 2006 have been excluded. Accordingly, the resulting refining and wholesale marketing gross margin per gallon statistic will be higher than that same statistic calculated from amounts determined under previous accounting practices. The effect of this change on the refining and wholesale marketing gross margin per gallon for the third quarter of 2006 was not significant.

Critical Accounting Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material.

There have been no significant changes to our critical accounting estimates subsequent to December 31, 2005.

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Results of Operations

Consolidated Results

Total revenues for the third quarters and first nine months of 2006 and 2005 are summarized by segment in the following table:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2006	2005	2006	2005
E&P	$ 2,265	$ 1,835	$ 7,081	$ 5,454
RM&T	14,277	15,460	44,289	41,139
IG	30	92	130	197
Segment revenues	16,572	17,387	51,500	46,790
Elimination of intersegment revenues	(201)	(228)	(593)	(586)
Gain (loss) on long-term U.K. natural gas contracts	121	(82)	182	(306)
Total revenues	$ 16,492	$ 17,077	$ 51,089	$ 45,898
Items included in both revenues and costs and expenses:				
Consumer excise taxes on petroleum products and merchandise	$ 1,297	$ 1,217	$ 3,739	$ 3,511
Matching crude oil and refined petroleum product buy/sell transactions:				
E&P		30	16	100
RM&T	237	3,403	5,233	9,707
Total buy/sell transactions included in revenues	$ 237	$ 3,433	$ 5,249	$ 9,807

E&P segment revenues increased by $430 million in the third quarter of 2006 and $1.627 billion for the first nine months of 2006 from the comparable prior-year periods. The increases were primarily due to higher liquid hydrocarbon sales prices and sales volumes in all regions. The largest sales volume increase for the period was in Libya, where the first crude oil sales occurred in the first quarter of 2006 and where sales volumes totaled 79,000 boepd for the third quarter of 2006. Included in these sales volumes were 2.8 million barrels of oil, or 30,000 boepd, produced and sold during the quarter that were owed to our account upon the resumption of our operations in Libya.

Excluded from E&P segment revenues are a gain of $121 million for the third quarter of 2006 and a loss of $82 million for the third quarter of 2005 on long-term natural gas contracts in the United Kingdom that are accounted for as derivative instruments. Similarly, for the first nine months of 2006 and 2005, a gain of $182 million and a loss of $306 million are excluded from E&P segment revenues.

RM&T segment revenues decreased by $1.183 billion in the third quarter of 2006 but increased $3.150 billion in the first nine months of 2006 when compared to the prior-year periods. The portion of RM&T revenues reported for matching buy/sell transactions decreased $3.166 billion and $4.474 billion in the same periods as a result of the change in accounting for these transactions effective April 1, 2006, discussed above. Excluding matching buy/sell transactions, the increases in revenues in both periods primarily reflected higher refined petroleum product prices and sales volumes.

For additional information on segment results, see Segment Income.

Cost of revenues for the third quarter and first nine months of 2006 increased by $435 million and $4.886 billion from the comparable prior-year periods. The increases in both periods are primarily in the RM&T segment and resulted mainly from higher acquisition costs for crude oil and other refinery charge and blend stocks. Additionally in the first nine months of 2006, we experienced higher acquisition costs for refined products and higher RM&T manufacturing costs, primarily a result of higher purchased energy and maintenance costs.

Depreciation, depletion and amortization for the third quarter and first nine months of 2006 increased $42 million and $180 million from the comparable prior-year periods. The Detroit refinery expansion completed in the fourth quarter of 2005 contributed to the RM&T depreciation expense increases in both periods. In addition, RM&T segment depreciation expense increased in the nine-month period as a result of the increase in asset value recorded for our acquisition of the 38 percent interest in MPC on June 30, 2005. E&P segment depreciation expense for the first nine months of 2006 included a $20 million impairment of capitalized costs related to the Camden Hills field in the Gulf of

Mexico and the associated Canyon Express pipeline. Natural gas production from the Camden Hills field ended during the first quarter of 2006 as a result of increased water production from the well.

Selling, general and administrative expenses decreased $24 million in the third quarter of 2006 and increased $44 million in the first nine months of 2006 over the same periods of 2005. The decrease for the third quarter of 2006 was primarily the result of contributions to hurricane relief efforts and higher stock-based compensation in the prior year. Selling, general and administrative expenses for the first nine months of 2006 increased primarily because personnel and staffing costs, such as employee salaries and outside consultant fees, have increased throughout the year primarily as a result of variable compensation arrangements and increased business activity. The increase for the nine months also reflects costs incurred during the second quarter of 2006 related to disaster preparedness programs.

Exploration expenses were $97 million in the third quarter of 2006 compared to $64 million in the third quarter of 2005 and were $234 million in the first nine months of 2006 compared to $130 million in the same period of 2005. Exploration expenses related to dry wells and other write-offs totaled $99 million for the first nine months of 2006, including $41 million in the third quarter of 2006, primarily related to a dry well in West Africa and a well in Equatorial Guinea that was written off when we decided to relinquish the related acreage. Additional write-offs of $58 million in the first nine months of 2006 were primarily related to a well offshore Angola, the Abbott well in the Gulf of Mexico, the Davan well in the United Kingdom and the Soulandaka well in Gabon.

Net interest and other financing costs (income) reflected a net $7 million of income in the third quarter of 2006 compared to a net $31 million expense for the third quarter of 2005. Net interest and other financing costs decreased $92 million in the first nine months of 2006 compared to the prior-year period. These favorable changes primarily resulted from increased interest income due to higher interest rates and average cash balances, foreign currency exchange gains, lower interest expense and greater capitalized interest.

Minority interest in the income of MPC decreased $384 million in the first nine months of 2006 from the comparable 2005 period due to the completion of our acquisition of the 38 percent interest in MPC held by Ashland Inc. on June 30, 2005.

Provision for income taxes increased $872 million and $2.305 billion in the third quarter and first nine months of 2006 from the comparable prior-year periods primarily due to increased income from continuing operations before income taxes as discussed above. Our effective income tax rates for the third quarter and first nine months of 2006 were 45.0 percent and 45.9 percent compared to 37.9 percent and 36.3 percent for the same periods of 2005. The increases are primarily a result of the income taxes related to our Libyan operations, where the statutory income tax rate is in excess of 90 percent. The following is an analysis of the effective tax rates for continuing operations for the third quarters and first nine months of 2006 and 2005:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Statutory U.S. income tax rate	35.0%	35.0%	35.0%	35.0%
Effects of foreign operations	9.2	(0.9)	9.9	(0.8)
State and local income taxes after federal income tax effects	2.9	3.6	2.3	2.4
Other tax effects	(2.1)	0.2	(1.3)	(0.3)
Effective income tax rate for continuing operations	45.0%	37.9%	45.9%	36.3%

Discontinued operations reflects the operations of our former Russian oil exploration and production businesses which were sold in June 2006. An after-tax gain on the disposal of $243 million is included in discontinued operations for the first nine months of 2006. See Note 4 to the consolidated financial statements, Discontinued Operations, for additional information.

Segment Results

Effective January 1, 2006, we revised our measure of segment income to include the effects of minority interests and income taxes related to the segments. In addition, the results of activities primarily associated with the marketing of our equity natural gas production, which had been presented as part of the Integrated Gas segment prior to 2006, are now included in the Exploration and Production segment. Segment results for all periods presented reflect these changes.

As discussed previously, we sold our Russian oil exploration and production businesses during the second quarter of 2006. The activities of these operations have been reported as discontinued operations and therefore are excluded from segment results for all periods presented.

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Segment income for the third quarters and the first nine months of 2006 and 2005 is summarized in the following table.

(Dollars in millions)	Third Quarter Ended September 30, 2006	Third Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
E&P				
United States	$ 218	$ 247	$ 706	$ 682
International	354	126	990	529
E&P segment	572	373	1,696	1,211
RM&T	1,026	473	2,262	863
IG	(2)	22	23	44
Segment income	1,596	868	3,981	2,118
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(52)	(91)	(217)	(235)
Gain (loss) on long-term U.K. natural gas contracts	58	(48)	93	(178)
Gain on sale of minority interests in EG Holdings		21		21
Ohio tax legislation				15
U.K. tax legislation	21		21	
Discontinued operations		20	277	26
Net income	$ 1,623	$ 770	$ 4,155	$ 1,767

United States E&P income in the third quarter of 2006 was $29 million lower than the same period of 2005, while income in the first nine months of 2006 was $24 million higher than the same period of 2005. Pretax income in the third quarter of 2006 decreased $22 million and the effective income tax rate increased to 38 percent from 34 percent in the third quarter of 2005. Pretax income in the first nine months of 2006 increased $59 million and the effective income tax rate was 38 percent and 36 percent in 2006 and 2005, respectively.

Revenues for the third quarter of 2006 were down when compared to the same quarter of 2005 primarily as a result of lower natural gas sales volumes and prices. Natural gas sales volumes of 522 million cubic feet per day (mmcfd) were down nearly 7 percent from the third quarter of 2005. The average realized natural gas price of $5.62 per thousand cubic feet (mcf) for the third quarter of 2006 was 94 cents lower than the $6.56 per mcf realized in the third quarter of 2005. These revenue declines were partially offset by higher liquid hydrocarbon prices which increased to an average of $60.37 per barrel (bbl) for the third quarter of 2006 from $52.38 per bbl in the comparable period of 2005. Liquid hydrocarbon sales volumes increased slightly between periods. Included in E&P segment revenues were derivative gains of $3 million and $27 million in the third quarter and first nine months of 2006 compared to losses of $22 million and $20 million in the comparable periods of 2005.

Revenues increased in the first nine months of 2006 primarily as a result of higher liquid hydrocarbon and natural gas prices. Our domestic average realized liquid hydrocarbon price was $56.38 per bbl for the first nine months of 2006 compared to $44.24 per bbl in the comparable prior-year period. The average realized natural gas price of $5.89 per mcf was also higher than the $5.76 per mcf realized in the corresponding 2005 period. Natural gas sales volume declines, primarily due to the cessation of production from the Camden Hills field in the first quarter of 2006, offset much of the impact of these price increases in the first nine months of 2006.

Both periods of 2006 were impacted by higher variable costs, including depreciation, depletion and amortization expense, and by higher exploration expenses. Additionally, the first nine months of 2005 included business interruption insurance proceeds of $53 million associated with Hurricane Ivan storm-related claims.

International E&P income increased $228 million and $461 million in the third quarter and first nine months of 2006. Pretax income increased $664 million and $1.581 billion in the same periods, while the effective income tax rate increased from 37 percent to 59 percent in the third quarter of 2006 and from 36 percent to 59 percent in the first nine- months of 2006. These increases in the effective income tax rates are primarily a result of the income taxes related to our Libyan operations, where the statutory income tax rate is in excess of 90 percent.

The increases in pretax income were primarily the result of increases in revenues from higher liquid hydrocarbon and natural gas prices and higher liquid hydrocarbon sales volumes in the third quarter and first nine months of 2006. Our international average realized liquid hydrocarbon prices were $64.07 per bbl and $62.63 per bbl in the third quarter and first nine months of 2006 compared to $52.53 per bbl and $48.07 per bbl in the same prior-year periods. Our average realized natural gas prices of $4.10 per mcf and $5.41 per mcf in the third quarter and first nine months of 2006 were higher than the $3.12 per mcf and $3.62 per mcf in the corresponding periods of 2005. International liquid hydrocarbon sales volumes were 170 mbpd and 151 mbpd in the third quarter and first nine months of 2006 as compared to 59 mbpd and 79 mbpd in the comparable periods of 2005 primarily due to our resumption of production in Libya, including the production and sale of 2.8 million barrels of oil in the third quarter of 2006 that were owed to our account upon our re-entry to Libya. The increase in sales volumes in the nine-month period also reflects the effect of the Equatorial Guinea condensate expansion project which reached full production levels in the third quarter of 2005. Natural gas sales volumes averaged 197 mmcfd in the third quarter of 2006 and 302 mmcfd in the first nine months of 2006, down 20 percent and 10 percent from the comparable periods of 2005. The lower natural gas sales volumes were primarily related to lower sales in Equatorial Guinea as a result of reduced demand for gas associated with downtime at the AMPCO methanol plant in the second and third quarters of 2006.

These increases in revenues were partially offset by higher international income taxes, dry well costs, operating costs and depreciation, depletion and amortization linked to the larger sales volumes in Libya, the U.K. and Equatorial Guinea in both periods of 2006.

RM&T segment income increased by $553 million and $1.399 billion from the third quarter and first nine months of 2005. Pretax income increased $869 million and $2.217 billion in the same periods, while the effective income tax rate decreased from 42 percent to 39 percent in the third quarter of 2006 and from 41 percent to 39 percent in the first nine months of 2006 compared to the 2005 periods. Segment income in the nine-month period of 2006 benefited from the 38 percent minority interest in MPC that we acquired on June 30, 2005. In the first nine months of 2005, the pretax earnings reduction related to the minority interest was $376 million.

A key driver of the increase in RM&T pretax income in both periods was our refining and wholesale marketing gross margin, which averaged 32.71 cents per gallon in the third quarter of 2006 and 24.78 cents per gallon in the first nine months of 2006, compared to 17.74 cents per gallon and 13.69 cents per gallon in the comparable periods of 2005. These results exceeded the change in the relevant market indicators period-over-period. Included in the refining and wholesale marketing gross margin were derivative gains of $384 million and $206 million in the third quarter and first nine months of 2006 compared to losses of $271 million and $410 million in the comparable 2005 periods. This change reflects both improvements in the realized effects of our derivatives programs as well as unrealized effects as a result of marking open derivatives positions to market. See further discussion under Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Crude oil refined during the third quarter 2006 averaged 1,031,000 bpd, 51,000 bpd higher than during the third quarter of 2005. In addition, total refinery throughputs totaled 1,249,000 bpd for the third quarter of 2006, approximately 4.5 percent higher than the 1,195,000 bpd during the third quarter of 2005. We were able to achieve both of these increases primarily as a result of the expansion of our Detroit refinery from 74,000 to 100,000 bpd that was completed during the fourth quarter of 2005.

IG segment income decreased $24 million and $21 million in the third quarter and first nine months of 2006 compared to the same periods of 2005 primarily as a result of lower income from our equity method investment in AMPCO in the third quarter of 2006. AMPCO experienced 35 days of downtime during the third quarter of 2006 related to compressor problems.

Cash Flows and Liquidity

Cash Flows

Net cash provided from operating activities totaled $3.745 billion in the first nine months of 2006, compared with $1.973 billion in the first nine months of 2005. The $1.772 billion increase primarily reflects the impact of higher liquid hydrocarbon prices and our increased refining and wholesale marketing gross margin.

Net cash used in investing activities totaled $1.852 billion in the first nine months of 2006, down $459 million from the same period of 2005 primarily as a result of the $832 million net cash proceeds from the sale of our Russian oil exploration and production businesses in June 2006. Capital expenditures were $2.405 billion compared with $1.952 billion for the comparable prior-year period. E&P spending increased $689 million, reflecting higher expenditures related to the Alvheim development offshore Norway, the Neptune development in the Gulf of Mexico, and acreage acquisitions in the Bakken Shale and the Piceance Basin. Partially offsetting the E&P spending increases was a $277 million decrease in IG spending as a result of major projects such as the LNG plant nearing completion. For information regarding capital expenditures by segment, refer to Supplemental Statistics. Cash paid for acquisitions during the first nine months of 2006 totaled $543 million, primarily related to the initial $520 million payment associated with our re-entry into Libya.

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Net cash used in financing activities was $1.726 billion in the first nine months of 2006, compared to $1.976 billion in the first nine months of 2005. Significant uses of cash in financing activities during the 2006 period included stock repurchases of $1.146 billion under a previously announced plan discussed under Liquidity and Capital Resources below, the repayment of our $300 million 6.65% notes that matured during the first quarter and dividend payments of $407 million. The 2005 activity includes the repayment of $1.9 billion in debt immediately after our June 2005 acquisition of the minority interest in MPC.

Dividends to Stockholders

On October 25, 2006, our Board of Directors declared a dividend of 40 cents per share, payable December 11, 2006, to stockholders of record at the close of business on November 16, 2006.

Derivative Instruments

See Quantitative and Qualitative Disclosures About Market Risk for a discussion of derivative instruments and associated market risk.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are cash on hand, internally generated cash flow from operations, committed credit facilities, and access to both the debt and equity capital markets. Our ability to access the debt capital market is supported by our investment grade credit ratings. Our senior unsecured debt is currently rated investment grade by Standard and Poor s Corporation, Moody s Investor Services, Inc. and Fitch Ratings with ratings of BBB+, Baa1 and BBB+, respectively. Because of the liquidity and capital resource alternatives available to us, including internally generated cash flow, we believe that our short-term and long-term liquidity is adequate to fund operations, including our capital spending programs, stock repurchase program, debt repurchases or repayments, and any amounts that may ultimately be paid in connection with contingencies.

Effective May 4, 2006, we entered into an amendment to our $1.5 billion five-year revolving credit agreement, expanding the size of the facility to $2.0 billion and extending the termination date from May 2009 to May 2011. Concurrent with this amendment, the $500 million MPC revolving credit facility was terminated. At September 30, 2006, there were no borrowings against our facility.

As a condition of the closing agreements for our acquisition of the minority interest in MPC, we are required to maintain MPC on a stand-alone basis financially for a two-year period. During this period of time, capital contributions into MPC are prohibited and MPC is prohibited from incurring additional debt, except for borrowings under an existing intercompany loan facility to fund the expansion project at our Detroit refinery and in the event of limited extraordinary circumstances. MPC was permitted to use its revolving credit facility only for short-term working capital requirements in a manner consistent with past practices. There are no restrictions against MPC making intercompany loans or declaring dividends to its parent. We believe that the existing cash balances of MPC and cash provided from its operations will be adequate to meet its liquidity requirements.

As of September 30, 2006, $1.7 billion aggregate amount of common stock, preferred stock and other equity securities, debt securities, trust preferred securities or other securities, including securities convertible into or exchangeable for other equity or debt securities were available to be issued under our $2.7 billion universal shelf registration statement filed in 2002.

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Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 6 percent at September 30, 2006, compared to 11 percent at year-end 2005 as shown below. This includes $519 million of debt that is serviced by United States Steel Corporation (United States Steel). We continually monitor our spending levels, market conditions and related interest rates to maintain what we perceive to be reasonable debt levels.

(Dollars in millions)	September 30, 2006	December 31, 2005
Long-term debt due within one year	$ 460	$ 315
Long-term debt	3,230	3,698
Total debt	$ 3,690	$ 4,013
Cash	$ 2,797	$ 2,617
Equity	$ 14,452	$ 11,705
Calculation:		
Total debt	$ 3,690	$ 4,013
Minus cash	2,797	2,617
Total debt minus cash	893	1,396
Total debt	3,690	4,013
Plus equity	14,452	11,705
Minus cash	2,797	2,617
Total debt plus equity minus cash	$ 15,345	$ 13,101
Cash-adjusted debt-to-capital ratio	6%	11%

In the fourth quarter of 2006, we have repurchased a portion of our debt with a face value of $87 million. The debt was repurchased at a weighted average price equal to 123 percent of face value. We will continue to evaluate debt repurchase opportunities as such opportunities arise.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies.

Stock Repurchase Program

On January 29, 2006, our Board of Directors authorized the repurchase of up to $2 billion of common stock over a period of two years. Such purchases will be made during this period as our financial condition and market conditions warrant. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. We will use cash on hand, cash generated from operations or cash from available borrowings to acquire shares. During the first nine months of 2006, Marathon acquired 14.4 million common shares, at an acquisition cost of $1.146 billion. On July 26, 2006, we announced that purchases under the program were being accelerated. We currently anticipate repurchasing approximately $1.5 billion of our common stock by December 31, 2006, with the balance of the shares being repurchased in 2007. This program does not include specific price targets and may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion.

The forward-looking statements about our common stock repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially are changes in prices of and demand for crude oil, natural gas and refined products, actions of competitors, disruptions or interruptions of our production or refining operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other operating and economic considerations.

Contractual Cash Obligations

As of September 30, 2006, our contractual cash obligations had increased by $930 million from December 31, 2005. Purchase obligations under crude oil, refinery feedstocks and ethanol contracts increased $1.4 billion primarily as a result of increased contract volumes and prices. Partially offsetting this increase were decreases in long-term debt obligations from the repayment of $300 million of notes that matured during the first quarter of 2006, and in future operating lease obligations related to the Russian businesses that were sold during the second quarter of 2006. There have been no other significant changes to our obligations to make future payments under existing contracts subsequent to December 31, 2005. The portion of our obligations to make future payments under existing contracts that have been assumed by United States Steel has not changed significantly subsequent to December 31, 2005.

Other Obligations and Planned Cash Outlays

An additional payment, estimated to be $212 million, is payable by us during the fourth quarter of 2006 under our agreement with the National Oil Corporation of Libya to return to our operations in the Waha concessions in Libya.

We also plan to make contributions totaling $350 million to our funded pension plans during the fourth quarter of 2006.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under generally accepted accounting principles. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources; and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources. There have been no significant changes to our off-balance sheet arrangements subsequent to December 31, 2005.

Nonrecourse Indebtedness of Investees

Certain of our investees have incurred indebtedness that we do not support through guarantees or otherwise. If we were obligated to share in this debt on a pro rata ownership basis, our share would have been $285 million as of September 30, 2006. Of this amount, $162 million relates to Pilot Travel Centers LLC (PTC). If any of these investees default, we have no obligation to support the debt. Our partner in PTC has guaranteed $125 million of the total PTC debt.

Obligations Associated with the Separation of United States Steel

We remain obligated (primarily or contingently) for certain debt and other financial arrangements for which United States Steel has assumed responsibility for repayment under the terms of the Separation. (See the discussion of the Separation in our 2005 Annual Report on Form 10-K.) United States Steel s obligations to Marathon are general unsecured obligations that rank equal to its accounts payable and other general unsecured obligations. If United States Steel fails to satisfy these obligations, we would become responsible for repayment. Under the Financial Matters Agreement, United States Steel has all of the existing contractual rights under the leases assumed from Marathon, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed leases, other than extensions set forth in the terms of the assumed leases.

As of September 30, 2006, we have obligations totaling $563 million that have been assumed by United States Steel. Of the total $563 million, obligations of $527 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet (current portion $20 million; long-term portion $507 million). The remaining $36 million was related to operating leases and contingent liabilities of United States Steel.

Environmental Matters

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately recovered in the prices of our products and services, operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil, refined products, and refinery feedstocks.

Of particular significance to our refining operations are U.S. Environmental Protection Agency (EPA) regulations that require reduced sulfur levels starting in 2004 for gasoline and 2006 for diesel fuel. We have achieved compliance with these regulations and began the production of ultra low sulfur diesel fuel prior to the June 1, 2006 deadline. The cost of achieving compliance is approximately $865 million.

During 2001, MPC entered into a New Source Review consent decree and settlement of alleged Clean Air Act (CAA) and other violations with the EPA covering all of its refineries. The settlement committed MPC to specific control technologies and implementation schedules for environmental expenditures and improvements to its refineries over approximately an eight-year period. In addition, MPC has been working on certain agreed upon supplemental environmental projects as part of this settlement of an enforcement action for alleged CAA violations and these should be completed in 2006 or 2007.

The oil industry across the U.K. continental shelf is making reductions in the amount of oil in its produced water discharges pursuant to the Department of Trade and Industry initiative under the Oil Pollution Prevention and Control Regulations (OSPAR) of 2005. In compliance with these regulations, we expect to spend an estimated $12 million in capital costs on the OSPAR project for Brae field to make the required reductions of oil in its produced water discharges.

In June 2006, Marathon and another operator filed a Complaint for Declaratory Judgment in Montana State District Court against the Montana Board of Environmental Review (MBER), and the Montana Department of Environmental Quality (MDEQ), seeking to set aside and declare invalid certain 2006 regulations (and underlying 2003 regulations) of the MBER that single out the coal bed natural gas industry and a few streams in eastern Montana for excessively severe and unjustified restrictions for surface water discharges of produced water from coal bed methane operations. None of the streams affected by the regulations suffers impairment from coal bed natural gas discharges. The complaint alleges that MBER violated Montana State law in that it adopted regulations without sound scientific justification, proposed water quality standards more stringent than federal law without required justification, and neglected to prepare an environmental impact statement to address resultant harm to jobs and communities from the regulations.

In September 2006, Marathon and other oil and gas companies joined the State of Wyoming in filing a Petition for Review against the U.S. EPA in the U.S. District Court for the District of Wyoming. These actions seek a Court order mandating the EPA to disapprove Montana s 2006 amended water quality standards, on grounds that the standards lack sound scientific justification, they are arbitrary and capricious, and were adopted contrary to law. These September 2006 actions have been consolidated with our pending April 2006 action against the EPA in the same Court. The water quality amendments at issue, if approved, could require more stringent discharge limits and have the potential to require certain Wyoming coal bed methane operations to perform more costly water treatment or inject produced water. Approval of these standards could delay or prevent obtaining permits needed to discharge produced water to streams flowing from Wyoming into Montana.

There have been no other significant changes to our environmental matters subsequent to December 31, 2005.

Other Contingencies

We are the subject of, or a party to, a number of pending or threatened legal actions, contingencies and commitments involving a variety of matters, including laws and regulations relating to the environment. The ultimate resolution of these contingencies could, individually or in the aggregate, be material to us. However, we believe that we will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably to us. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Accounting Standards Not Yet Adopted

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106, and 132(R). This standard requires an employer to: (a) recognize in its statement of financial position an asset for a plan s overfunded status or a liability for a plan s underfunded status; (b) measure a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year (with limited exceptions); and (c) recognize changes in the funded status of a plan in the year in which the changes occur through comprehensive income. The funded status of a plan is measured as the difference between plan assets at fair value and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation and for any other postretirement plan it is the accumulated postretirement benefit obligation. We are required to recognize the funded status of our plans and to provide the additional required disclosures in our December 31, 2006 consolidated financial statements. We currently measure the plan assets and benefit obligations of our pension and other postretirement plans as of December 31. Upon adoption, we expect to increase our recorded liabilities for pension and other postretirement benefits by $650 million to $700 million. After related income tax effects, the net decrease in stockholders equity is estimated to be between $400 million and $430 million.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Marathon, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In September 2006, the FASB issued FASB Staff Position (FSP) No. AUG AIR-1, Accounting for Planned Major Maintenance Activities. This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods. We expense such costs in the same annual period as incurred; however, estimated annual major maintenance costs are recognized as expense throughout the year on a pro rata basis. As such, adoption of FSP No. AUG AIR-1 will have no impact on our annual consolidated financial statements but will require us to retrospectively adjust our results of operations for prior interim periods because major maintenance costs will no longer be recognized on a pro rata basis throughout the year. We are required to adopt the FSP effective January 1, 2007, but early adoption is permitted. We are currently evaluating the provisions of FSP No. AUG AIR-1 to determine the impact on our interim consolidated financial statements.

In September 2006, the SEC issued SEC Staff Accounting Bulletin (SAB) No. 108, Financial Statements Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 addresses how a registrant should quantify the effect of an error in the financial statements for purposes of assessing materiality and requires that the effect be computed using both the current year income statement perspective (rollover) and the year end balance sheet perspective (iron curtain) methods for fiscal years ending after November 15, 2006. If a change in the method of quantifying errors is required under SAB No. 108, this represents a change in accounting policy; therefore, if the use of both methods results in a larger, material misstatement than the previously applied method, the financial statements must be adjusted. SAB No. 108 allows the cumulative effect of such adjustments to be made to opening retained earnings upon adoption. We do not expect adoption of SAB No. 108 to have an effect on our consolidated results of operations, financial position or cash flows.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. For Marathon, the provisions of FIN No. 48 are effective January 1, 2007. We are currently evaluating the provisions of FIN No. 48 to determine the impact on our consolidated financial statements.

In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). Included in the scope of this issue are any taxes assessed by a governmental authority that are imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF concluded that the presentation of such taxes on a gross basis (included in revenues and costs) or a net basis (excluded from revenues) is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22. In addition, the amounts of such taxes reported on a gross basis must be disclosed if those tax amounts are significant. For Marathon, the disclosure prescribed by this consensus is required in our 2007 consolidated financial statements, but early application is permitted.

In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets An Amendment of FASB Statement No. 140. This statement amends SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, with respect to the accounting for separately recognized servicing assets and servicing liabilities. We are required to adopt SFAS No. 156 effective January 1, 2007. We do not expect adoption of this statement to have a significant effect on our consolidated results of operations, financial position or cash flows.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140. SFAS No. 155 simplifies the accounting for certain hybrid financial instruments, eliminates the interim FASB guidance which provides that beneficial interests in securitized financial assets are not subject to the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and eliminates the restriction on the passive derivative instruments that a qualifying special-purpose entity may hold. For Marathon, SFAS No. 155 is effective for all financial instruments acquired or issued on or after January 1, 2007. We do not expect adoption of this statement to have a significant effect on our consolidated results of operations, financial position or cash flows.

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ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Management Opinion Concerning Derivative Instruments

Management has authorized the use of futures, forwards, swaps and options to manage exposure to market fluctuations in commodity prices, interest rates and foreign currency exchange rates.

We use commodity-based derivatives to manage price risk related to the purchase, production or sale of crude oil, natural gas and refined products. To a lesser extent, we are exposed to the risk of price fluctuations on natural gas liquids and petroleum feedstocks used as raw materials, and purchases of ethanol.

Our strategy has generally been to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. We use a variety of derivative instruments, including option combinations, as part of the overall risk management program to manage commodity price risk in our different businesses. As market conditions change, we evaluate our risk management program and could enter into strategies that assume market risk whereby cash settlement of commodity-based derivatives will be based on market prices.

Our E&P segment primarily uses commodity derivative instruments selectively to protect against price decreases on portions of our future production when deemed advantageous to do so. We also use derivatives to protect the value of natural gas purchased and injected into storage in support of production operations. We use commodity derivative instruments to mitigate the price risk associated with the purchase and subsequent resale of natural gas on purchased volumes and anticipated sales volumes.

Our RM&T segment uses commodity derivative instruments:

- to mitigate the price risk:
  - o between the time foreign and domestic crude oil and other feedstock purchases for refinery supply are priced and when they are actually refined into salable petroleum products,
  - o associated with anticipated natural gas purchases for refinery use,
  - o associated with freight on crude oil, feedstocks and refined product deliveries, and
  - o on fixed price contracts for ethanol purchases;
- to protect the value of excess refined product, crude oil and liquefied petroleum gas inventories;
- to protect margins associated with future fixed price sales of refined products to non-retail customers;
- to protect against decreases in future crack spreads;
- to take advantage of trading opportunities identified in the commodity markets.

We use financial derivative instruments in each of our segments to manage foreign currency exchange rate exposure on foreign currency denominated capital expenditures, operating expenses and foreign tax payments.

We use financial derivative instruments to manage interest rate risk exposures. As we enter into these derivatives, assessments are made as to the qualification of each transaction for hedge accounting.

We believe that our use of derivative instruments, along with risk assessment procedures and internal controls, does not expose us to material risk. However, the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods. We believe that the use of these instruments will not have a material adverse effect on our consolidated financial position or liquidity.

Commodity Price Risk

Sensitivity analyses of the incremental effects on income from operations (IFO) of hypothetical 10 percent and 25 percent changes in commodity prices for open derivative commodity instruments as of September 30, 2006 are provided in the following table:

	Incremental Decrease in IFO Assuming a Hypothetical Price Change of [a]:	
(Dollars in millions)	10%	25%
Commodity Derivative Instruments: [b][c]		
Crude oil [d]	$ 116(e)	$ 164(e)
Natural gas [d]	71(e)	177(e)
Refined products [d]	7(f)	17(f)

(a) We remain at risk for possible changes in the market value of derivative instruments; however, such risk should be mitigated by price changes in the underlying hedged item. Effects of these offsets are not reflected in the sensitivity analyses. Amounts reflect hypothetical 10 percent and 25 percent changes in closing commodity prices, excluding basis swaps, for each open contract position at September 30, 2006. Included in the natural gas impacts shown above are $79 million and $198 million related to the long-term U.K. natural gas contracts for hypothetical price changes of 10 percent and 25 percent, respectively. We evaluate our portfolio of derivative commodity instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. We are also exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed continuously and master netting agreements are used when practical. Changes to the portfolio after September 30, 2006, would cause future IFO effects to differ from those presented in the table.

(b) The number of net open contracts for the E&P segment varied throughout the third quarter of 2006, from a low of 341 contracts on August 16, 2006 to a high of 1,098 contracts on September 27, 2006, and averaged 685 for the quarter. The number of net open contracts for the RM&T segment varied throughout the third quarter of 2006, from a low of 15,663 contracts on July 1, 2006 to a high of 25,123 contracts on August 23, 2006, and averaged 20,754 for the quarter. The derivative commodity instruments used and hedging positions taken will vary and, because of these variations in the composition of the portfolio over time, the number of open contracts by itself cannot be used to predict future income effects.

(c) The calculation of sensitivity amounts for basis swaps assumes that the physical and paper indices are perfectly correlated. Gains and losses on options are based on changes in intrinsic value only.

(d) The direction of the price change used in calculating the sensitivity amount for each commodity reflects that which would result in the largest incremental decrease in IFO when applied to the commodity derivative instruments used to hedge that commodity.

(e) Price increase.

(f) Price decrease.

E&P Segment

Derivative gains of $3 million and $27 million were included in the third quarter and first nine months of 2006, and derivative losses of $22 million and $20 million were included in the third quarter and the first nine months of 2005. The results of activities primarily associated with the marketing of our equity natural gas production, which had been presented as part of the Integrated Gas segment prior to 2006, are included in the E&P segment for all periods presented.

Excluded from the E&P segment results were gains of $121 million and $182 million in the third quarter and first nine months of 2006 and losses of $82 million and $306 million in for the third quarter and the first nine months of 2005 related to long-term natural gas contracts in the United Kingdom that are accounted for as derivative instruments.

We continue to evaluate the commodity price risks related to our production and may enter into derivative commodity instruments when it is deemed advantageous. As a particular but not exclusive example, we may elect to use derivative commodity instruments to achieve minimum price levels on some portion of our production to support capital or acquisition funding requirements.

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RM&T Segment

We do not attempt to qualify commodity derivative instruments used in our RM&T operations for hedge accounting. As a result, we recognize in income all changes in the fair value of derivatives used in our RM&T operations. Pretax derivative gains and losses included in RM&T segment income for the third quarter and first nine months of 2006 and 2005 are summarized in the following table:

	Third Quarter Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2006	2005	2006	2005
Strategy:				
Mitigate price risk	$ 180	$ (100)	$ 75	$ (119)
Protect carrying values of excess inventories	208	(166)	130	(233)
Protect margin on fixed price sales	(11)	8	(1)	23
Protect crack spread values	7	(13)	2	(81)
Subtotal, non-trading activities	384	(271)	206	(410)
Trading activities	2	(42)		(76)
Total net derivative gains (losses)	$ 386	$ (313)	$ 206	$ (486)

Derivatives used in non-trading activities have an underlying physical commodity transaction. Derivative losses occur when market prices increase and generally are offset by gains on the underlying physical commodity transactions. Conversely, derivative gains occur when market prices decrease, which are generally offset by losses on the underlying physical commodity transactions. The income effect related to derivatives and the income effect related to the underlying physical transactions may not necessarily be recognized in income in the same period since we do not attempt to qualify commodity derivative instruments used in our RM&T operations for hedge accounting. The period-to-period improvement in net derivative gains or losses reflects changes in market conditions.

Other Commodity Related Risks

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. For example, New York Mercantile Exchange (NYMEX) contracts for natural gas are priced at Louisiana s Henry Hub, while the underlying quantities of natural gas may be produced and sold in the western United States at prices that do not move in strict correlation with NYMEX prices. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased exposure to basis risk. These regional price differences could yield favorable or unfavorable results. Over-the-counter transactions are being used to manage exposure to a portion of basis risk.

We are impacted by liquidity risk, caused by timing delays in liquidating contract positions due to a potential inability to identify a counterparty willing to accept an offsetting position. Due to the large number of active participants, liquidity risk exposure is relatively low for exchange-traded transactions.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. A sensitivity analysis of the projected incremental effect of a hypothetical 10 percent decrease in interest rates as of September 30, 2006 is provided in the following table:

(Dollars in millions)	Incremental Increase in Fair Value [(c)]

	Fair Value (b)	
Financial assets (liabilities) [(a)]		
Interest rate swap agreements	$ (26)	$ 10
Long-term debt, including that due within one year [(d)]	(3,924)	(143)

(a) Fair values of cash and cash equivalents, receivables, notes payable, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

(b) Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.

(c) Assumes a 10 percent decrease in the September 30, 2006 effective swap rate or a 10 percent decrease in the weighted average yield to maturity of our long-term debt at September 30, 2006, as appropriate.

(d) See below for sensitivity analysis.

At September 30, 2006, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to effects of interest rate fluctuations. This sensitivity is illustrated by the $143 million increase in the fair value of long-term debt assuming a hypothetical 10 percent decrease in interest rates. However, our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio would unfavorably affect our results of operations and cash flows only if we would elect to repurchase or otherwise retire all or a portion of our fixed-rate debt portfolio at prices above carrying value.

We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the fixed and floating interest rate mix of the debt portfolio. We have entered into several interest rate swap agreements, designated as fair value hedges, which effectively resulted in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates. There have been no unexpected changes to the positions subsequent to December 31, 2005.

Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in the foreign currency markets by locking in foreign currency rates. The aggregate effect on foreign exchange contracts of a hypothetical 10 percent change to quarter-end forward exchange rates would be approximately $14 million. There have been no significant changes to our exposure to foreign exchange rates subsequent to December 31, 2005.

Credit Risk

We are exposed to significant credit risk from United States Steel arising from the Separation. That exposure is discussed in Management s Discussion and Analysis of Financial Condition and Results of Operations Obligations Associated with the Separation of United States Steel.

Safe Harbor

These quantitative and qualitative disclosures about market risk include forward-looking statements with respect to management s opinion about risks associated with the use of derivative instruments. These statements are based on certain assumptions with respect to market prices and industry supply of and demand for crude oil, natural gas, refined products and other feedstocks. If these assumptions prove to be inaccurate, future outcomes with respect to our hedging programs may differ materially from those discussed in the forward-looking statements.

Item 4. Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-14 and 15d-14 under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this report based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective. During the quarter ended September 30, 2006, there were no changes in our internal controls over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal controls over financial reporting.

Marathon reviews and modifies its financial and operational controls on an ongoing basis to ensure that those controls are adequate to address changes in its business as it evolves. Marathon believes that its existing financial and operational controls and procedures are adequate.

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MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(Dollars in millions, except as noted)	Third Quarter Ended September 30, 2006	Third Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
SEGMENT INCOME (LOSS):				
Exploration and Production				
United States	$ 218	$ 247	$ 706	$ 682
International	354	126	990	529
E&P Segment	572	373	1,696	1,211
Refining, Marketing and Transportation[a]	1,026	473	2,262	863
Integrated Gas	(2)	22	23	44
Segment Income	1,596	868	3,981	2,118
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(52)	(91)	(217)	(235)
Long-term U.K. natural gas contracts	58	(48)	93	(178)
Gain on sale of minority interests in EG Holdings		21		21
Ohio tax legislation				15
U.K. tax legislation	21		21	
Discontinued operations		20	277	26
Net income	$ 1,623	$ 770	$ 4,155	$ 1,767
CAPITAL EXPENDITURES:				
Exploration and Production	$ 795	$ 361	$ 1,616	$ 927
Refining, Marketing and Transportation[a]	223	206	527	508
Integrated Gas[b]	72	205	236	513
Discontinued Operations		26	45	73
Corporate	7	1	26	4
Total	$ 1,097	$ 799	$ 2,450	$ 2,025
EXPLORATION EXPENSE:				
United States	$ 40	$ 18	$ 109	$ 59
International	57	46	125	71
Total	$ 97	$ 64	$ 234	$ 130
E&P OPERATING STATISTICS				
Net Liquid Hydrocarbon Sales (mbpd) [c]				
United States	72	71	77	76
Europe	29	11	35	31
Africa	141	48	116	48

Total International	170	59	151	79
Worldwide Continuing Operations	242	130	228	155
Discontinued Operations		27	16	25
Worldwide	242	157	244	180
Net Natural Gas Sales (mmcfd)[c][d]				
United States	522	562	536	570
Europe	141	159	237	244
Africa	56	86	65	93
Total International	197	245	302	337
Worldwide	719	807	838	907
Total Worldwide Sales (mboepd)	362	291	384	331
Discontinued operations (mboepd)		27	16	25
Continuing operations (mboepd)	362	264	368	306

(a) RM&T segment income for the first nine months of 2005 is net of $376 million pretax minority interest in MPC. RM&T capital expenditures include MPC at 100 percent.

(b) Includes Equatorial Guinea LNG Holdings at 100 percent.

(c) Amounts reflect sales after royalties, except for Ireland where amounts are before royalties.

(d) Includes natural gas acquired for

injection and subsequent resale of 36 mmcfd and 59 mmcfd in the third quarters of 2006 and 2005, and 45 mmcfd and 34 mmcfd for the first nine months of 2006 and 2005. Effective July 1, 2005, the methodology for allocating sales volumes between natural gas produced from the Brae complex and third-party natural gas production was modified, resulting in an increase in volumes representing natural gas acquired for injection and subsequent resale.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Third Quarter Ended September 30, 2006	Third Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
E&P OPERATING STATISTICS (continued)				
Average Realizations [e]				
Liquid Hydrocarbons ($ per bbl)				
United States	$ 60.37	$ 52.38	$ 56.38	$ 44.24
Europe	66.19	61.44	65.64	49.73
Africa	63.64	50.45	61.71	47.03
Total International	64.07	52.53	62.63	48.07
Worldwide Continuing Operations	62.96	52.45	60.51	46.19
Discontinued Operations		38.78	38.38	32.98
Worldwide	$ 62.96	$ 50.10	$ 59.02	$ 44.34
Natural Gas ($ per mcf)				
United States	$ 5.62	$ 6.56	$ 5.89	$ 5.76
Europe	5.65	4.69	6.83	4.90
Africa	0.24	0.25	0.25	0.25
Total International	4.10	3.12	5.41	3.62
Worldwide	$ 5.21	$ 5.52	$ 5.72	$ 4.96
RM&T OPERATING STATISTICS				
Refinery Runs(mbpd):				
Crude oil refined	1,031	980	989	972
Other charge and blend stocks	218	215	225	187
Total	1,249	1,195	1,214	1,159
Refined Product Yields(mbpd):				
Gasoline	655	658	655	624
Distillates	336	326	316	315
Propane	24	22	23	21
Feedstocks and special products	121	89	118	101
Heavy fuel oil	21	21	23	24
Asphalt	106	90	94	87
Total	1,263	1,206	1,229	1,172
Refined Products Sales Volumes (mbpd)[f][g]	1,434	1,467	1,437	1,438
	2	66	32	78

Matching buy/sell volumes included in refined products sales volumes (mbpd) [g]				
Refining and Wholesale Marketing Gross Margin ($/gallon)[h]	$ 0.3271	$ 0.1774	$ 0.2478	$ 0.1369
Number of SSA Retail Outlets	1,635	1,638		
SSA Gasoline and Distillate Sales [i]	867	825	2,459	2,392
SSA Gasoline and Distillate Gross Margin ($/gallon)	$ 0.1410	$ 0.1232	$ 0.1168	$ 0.1170
SSA Merchandise Sales	$ 729	$ 689	$ 2,029	$ 1,894
SSA Merchandise Gross Margin	$ 178	$ 162	$ 497	$ 468

(e) Excludes gains and losses on traditional derivative instruments and the unrealized effects of long-term U.K. natural gas contracts that are accounted for as derivatives.

(f) Total average daily volumes of all refined product sales to wholesale, branded and retail (SSA) customers.

(g) As a result of the change in accounting for matching buy/sell arrangements on April 1, 2006, the reported sales volumes will be lower than the volumes determined under the previous accounting practices. See

Note 2 to the consolidated financial statements, New Accounting Standards.

(h) Sales revenue less cost of refinery inputs, purchased products and manufacturing expenses, including depreciation. As a result of the change in accounting for matching buy/sell transactions on April 1, 2006, the resulting per gallon statistic will be higher than the statistic that would have been calculated from amounts determined under previous accounting practices. See Note 2 to the consolidated financial statements, New Accounting Standards.

(i) Millions of gallons.

Part II OTHER INFORMATION

Item 1. Legal Proceedings

Natural Gas Royalty Litigation

As reported in the 2005 Form 10-K, Marathon has been served in two qui tam cases, which allege that federal and Indian lessees violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids. One of the cases, U.S. ex rel Jack J Grynberg v. Alaska Pipeline Co., et al, which was primarily a gas measurement case, was dismissed as to Marathon on October 20, 2006 on jurisdictional grounds.

Marathon was served in October 2006 with an additional qui tam case, filed in the Western District of Oklahoma, which alleges that Marathon violated the False Claims Act by failing to pay the government past due interest resulting from royalty adjustments for crude oil, natural gas and other hydrocarbon production. The case is styled United States of America ex rel. Randy L. Little and Lanis G. Morris v. ENI Petroleum Co., et al. This case asserts that Marathon and other defendants are liable for past due interest, penalties, punitive damages and attorneys fees. Other than the specific allegation of underpayment for the month of May 2003 in the amount of $1,360, the parties in interest (Randy L. Little and Lanis G. Morris) have plead general damages with no other specific amounts against Marathon. The Department of Justice has filed notice with the Court that it will not intervene in the case. Marathon intends to vigorously defend this case.

U.S. EPA Litigation

In September 2006, Marathon and other oil and gas companies joined the State of Wyoming in filing a Petition for Review against the U.S. EPA in the U.S. District Court for the District of Wyoming. These actions seek a Court order mandating the EPA to disapprove Montana s 2006 amended water quality standards, on grounds that the standards lack sound scientific justification, they are arbitrary and capricious, and were adopted contrary to law. These September 2006 actions have been consolidated with our pending April 2006 action against the EPA in the same Court. The water quality amendments at issue, if approved, could require more stringent discharge limits and have the potential to require certain Wyoming coal bed methane operations to perform more costly water treatment or inject produced water. Approval of these standards could delay or prevent obtaining permits needed to discharge produced water to streams flowing from Wyoming into Montana.

Montana Litigation

In June 2006, Marathon and another operator filed a complaint for declaratory judgment in Montana State District Court against the Montana Board of Environmental Review (MBER), and the Montana Department of Environmental Quality (MDEQ), seeking to set aside and declare invalid certain 2006 regulations (and underlying 2003 regulations) of the MBER that single out the coal bed natural gas industry and a few streams in eastern Montana for excessively severe and unjustified restrictions for surface water discharges of produced water from coal bed methane operations. None of the streams affected by the regulations suffers impairment from coal bed natural gas discharges. The complaint alleges that MBER violated Montana State law in that it adopted regulations without sound scientific justification, proposed water quality standards more stringent than federal law without required justification, and neglected to prepare an environmental impact statement to address resultant harm to jobs and communities from the regulations.

Item 1A. Risk Factors

Marathon is subject to various risks and uncertainties in the course of its business. See the discussion of such risks and uncertainties under Item 1A. Risk Factors in our 2005 Annual Report on Form 10-K. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (a)(b)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (d)	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (d)
7/1/06 7/31/06	2,118,389	$ 88.97	2,116,000	$ 1,257,566,938
8/1/06 8/31/06	2,240,465	$ 89.25	2,239,151	$ 1,057,713,861
9/1/06 9/30/06	2,740,950(c)	$ 77.09	2,716,845	$ 848,202,039
Total	7,099,804	$ 84.47	7,071,996	

(a) 7,634 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) Under the terms of the transaction whereby Marathon acquired the minority interest in MPC and other businesses from Ashland Inc., Marathon paid Ashland Inc. shareholders cash in lieu of issuing fractional shares of Marathon common stock to which such holders would otherwise be entitled. Marathon acquired 4 shares due to acquisition share exchanges and Ashland Inc. share transfers pending at the closing of the transaction.

(c) 20,170 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the Dividend Reinvestment Plan) by the administrator of the Dividend Reinvestment Plan. Stock needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon.

(d) On January 29, 2006, our Board

of Directors authorized the repurchase of up to $2 billion of common stock over a period of two years. On July 26, 2006 we announced that purchases under the program were being accelerated. We currently anticipate repurchasing $1.5 billion of our common stock by December 31, 2006, with the balance of the shares being repurchased in 2007. This program does not include specific price targets and may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion.

Item 6. Exhibits

3.1 Marathon Oil Corporation By-Laws, effective October 25, 2006 (incorporated by reference to Exhibit 3.1 to Marathon Oil Corporation s Form 8-K filed on October 27, 2006)

10.1 First Amendment to the Marathon Petroleum Company LLC Excess Benefit Plan (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation s Form 8-K filed on October 10, 2006)

10.2 First Amendment to the Marathon Petroleum Company LLC Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Marathon Oil Corporation s Form 8-K filed on October 10, 2006)

10.3 Second Amendment to the Marathon Oil Company Excess Benefit Plan (incorporated by reference to Exhibit 10.3 to Marathon Oil Corporation s Form 8-K filed on October 10, 2006)

10.4 Second Amendment to the Marathon Oil Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.4 to Marathon Oil Corporation s Form 8-K filed on October 10, 2006)

10.5 Second Amendment to the Marathon Oil Company Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.1 to Marathon Oil Corporation s Form 8-K filed on October 27, 2006)

12.1 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

12.2 Computation of Ratio of Earnings to Fixed Charges

31.1 Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934

31.2 Certification of Senior Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934

32.1 Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350

32.2 Certification of Senior Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350

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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.

MARATHON OIL CORPORATION

By: Michael K. Stewart
Michael K. Stewart
Vice President, Accounting and
Controller

November 7, 2006

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