MARATHON OIL CORP
Form 10-Q
November 06, 2009

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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2009

OR

[ ] 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 or other jurisdiction of incorporation or organization)	(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, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of

Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes √ No

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

Large accelerated filer Ö		Accelerated filer
Non-accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company

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

There were 707,845,149 shares of Marathon Oil Corporation common stock outstanding as of October 30, 2009.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended September 30, 2009

INDEX

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).

Part I - Financial Information

Item 1. Financial Statements

MARATHON OIL CORPORATION

Consolidated Statements of Income (Unaudited)

(In millions, except per share data)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$ 14,335	$ 22,332	$ 37,509	$ 60,641
Sales to related parties	27	637	68	1,865
Income from equity method investments	75	270	184	735
Net gain on disposal of assets	5	15	200	37
Other income	35	47	112	151
Total revenues and other income	14,477	23,301	38,073	63,429
Costs and expenses:				
Cost of revenues (excludes items below)	10,963	16,978	28,080	49,342
Purchases from related parties	133	244	338	609
Consumer excise taxes	1,258	1,273	3,658	3,784
Depreciation, depletion and amortization	630	584	1,988	1,513
Selling, general and administrative expenses	323	349	935	1,008
Other taxes	98	126	296	376
Exploration expenses	55	108	181	367
Total costs and expenses	13,460	19,662	35,476	56,999
Income from operations	1,017	3,639	2,597	6,430
Net interest and other financing costs	(35)	(46)	(63)	(48)
Income from continuing operations before income taxes	982	3,593	2,534	6,382
Provision for income taxes	590	1,601	1,549	2,949
Income from continuing operations	392	1,992	985	3,433
Discontinued operations	21	72	123	136
Net income	$ 413	$ 2,064	$ 1,108	$ 3,569
Per Share Data				

Basic:				
Income from continuing operations	$ 0.55	$ 2.82	$ 1.39	$ 4.84
Discontinued operations	$ 0.03	$ 0.10	$ 0.17	$ 0.19
Net income per share	$ 0.58	$ 2.92	$ 1.56	$ 5.03
Diluted:				
Income from continuing operations	$ 0.55	$ 2.80	$ 1.39	$ 4.81
Discontinued operations	$ 0.03	$ 0.10	$ 0.17	$ 0.19
Net income per share	$ 0.58	$ 2.90	$ 1.56	$ 5.00
Dividends paid	$ 0.24	$ 0.24	$ 0.72	$ 0.72

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	September 30, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 1,370	$ 1,285
Receivables, less allowance for doubtful accounts of $13 and $6	4,288	3,094
Receivables from United States Steel	24	23
Receivables from related parties	56	33
Inventories	3,680	3,507
Other current assets	208	461
Total current assets	9,626	8,403
Equity method investments	1,991	2,080
Receivables from United States Steel	453	469
Property, plant and equipment, less accumulated depreciation,depletion and amortization of $16,631 and $15,581	31,115	29,414
Goodwill	1,424	1,447
Other noncurrent assets	806	873
Total assets	$ 45,415	$ 42,686
Liabilities		
Current liabilities:		
Accounts payable	$ 6,005	$ 4,712
Payables to related parties	50	21
Payroll and benefits payable	367	400
Accrued taxes	593	1,133
Deferred income taxes	611	561
Other current liabilities	513	828
Long-term debt due within one year	105	98
Total current liabilities	8,244	7,753
Long-term debt	8,581	7,087
Deferred income taxes	3,725	3,330
Defined benefit postretirement plan obligations	1,395	1,609
Asset retirement obligations	965	963
Payable to United States Steel	4	4
Deferred credits and other liabilities	410	531
Total liabilities	23,324	21,277
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – 5 million shares issued, 1 million and 3 million shares outstanding (no par value, 6 million shares authorized)	-	-

Common stock:					
Issued – 769 million and 767 million shares (par value $1 per share, 1.1 billion shares authorized)		769		767	
Securities exchangeable into common stock – 5 million shares issued, 1 million and 3 million shares outstanding (no par value, unlimited shares authorized)		-		-	
Held in treasury, at cost – 61 million and 61 million shares		(2,711		(2,720	)
Additional paid-in capital		6,730		6,696	
Retained earnings		17,857		17,259	
Accumulated other comprehensive loss		(554		(593	)
Total stockholders' equity		22,091		21,409	
Total liabilities and stockholders' equity	$	45,415	$	42,686	

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

3

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

(In millions)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$1,108	$3,569
Adjustments to reconcile net income to net cash provided by operating activities:		
Discontinued operations	(123)	(136)
Deferred income taxes	726	309
Depreciation, depletion and amortization	1,988	1,513
Pension and other postretirement benefits, net	(159)	118
Exploratory dry well costs and unproved property impairments	48	154
Net gain on disposal of assets	(200)	(37)
Equity method investments, net	42	(139)
Changes in the fair value of derivative instruments	7	218
Changes in:		
Current receivables	(1,241)	(396)
Inventories	(184)	(1,124)
Current accounts payable and accrued liabilities	742	595
All other operating, net	71	(57)
Net cash provided by continuing operations	2,825	4,587
Net cash provided by discontinued operations	81	220
Net cash provided by operating activities	2,906	4,807
Investing activities:		
Capital expenditures	(4,350)	(5,062)
Disposal of assets	573	68
Trusteed funds - withdrawals	16	402
Investing activities of discontinued operations	(66)	(106)
All other investing, net	63	(102)
Net cash used in investing activities	(3,764)	(4,800)
Financing activities:		
Short term debt, net	-	1,288
Borrowings	1,491	1,248
Debt issuance costs	(11)	(7)
Debt repayments	(43)	(1,331)
Purchases of common stock	-	(402)
Dividends paid	(510)	(511)
All other financing, net	(1)	17
Net cash provided by financing activities	926	302
Effect of exchange rate changes on cash:		
Continuing operations	19	(19)
Discontinued operations	(2)	(10)
Net increase in cash and cash equivalents	85	280
Cash and cash equivalents at beginning of period	1,285	1,199
Cash and cash equivalents at end of period	$1,370	$1,479

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

MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission 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 2009 classifications. Events and transactions subsequent to the balance sheet date have been evaluated through November 6, 2009, the date these consolidated financial statements were issued, for potential recognition or disclosure in the consolidated financial statements.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation ("Marathon") 2008 Annual Report on Form 10-K. The results of operations for the quarter and nine months ended September 30, 2009 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Recently Adopted

Subsequent events accounting standards were issued in May 2009 by the Financial Accounting Standards Board ("FASB"), which established the standards of accounting for and disclosing events that occur after the balance sheet date but before financial statements are issued or available to be issued. This codifies into the accounting standards guidance that existed in the auditing standards and should not significantly change the subsequent events that we report. We began applying these standards prospectively in the second quarter of 2009. The disclosures required appear in Note 1.

Interim disclosures about fair value of financial instruments were expanded by the FASB in April 2009. Disclosures about fair value of financial instruments are now required in interim reporting periods for publicly traded companies. This change was effective for the second quarter of 2009 and did not require disclosures for earlier periods presented for comparative purposes. Adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 11.

Guidance for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and guidance on identifying circumstances that indicate a transaction is not orderly was also issued in April 2009 by the FASB. It was effective for the second quarter of 2009 and did not require disclosures for earlier periods presented for comparative purposes. Adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting considerations for equity method investments were ratified by the FASB in November 2008, which address the initial measurement, decreases in value and changes in the level of ownership of the equity method investment. These were effective on a prospective basis on January 1, 2009 and for interim periods. Early application by an entity that has previously adopted an alternative accounting policy is not permitted. Since these were applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Guidance for determining whether instruments granted in share-based payment transactions are participating securities was issued by the FASB in June 2008. It provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share ("EPS") under the two-class method. It was effective January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) were adjusted retrospectively to conform to its provisions. While our restricted stock awards meet this definition of participating securities, this application did not have a significant impact on our reported EPS.

Guidance for determining the useful life of intangible assets was issued in April 2008 by the FASB. This guidance amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The intent is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. It was effective on January 1, 2009 and was applied prospectively to intangible assets acquired after the effective date, except

Notes to Consolidated Financial Statements (Unaudited)

for the disclosure requirements which must be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. Since this is applied prospectively, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Disclosures requirements for derivative instruments and hedging activities were expanded by the FASB in March 2008 to provide information regarding (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. Requirements include qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. The amendments were effective January 1, 2009 and encouraged, but did not require, disclosures for earlier periods presented for comparative purposes at initial adoption. The new disclosures required appear in Note 12.

Accounting for business combinations was revised by the FASB in December 2007. This significantly changes the accounting for business combinations. An acquiring entity will be required to recognize all the assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair value with limited exceptions. The definition of a business is expanded and is expected to be applicable to more transactions. In addition, there are changes in the accounting treatment for changes in control, step acquisitions, transaction costs, acquired contingent liabilities, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of a business combination and changes in income tax uncertainties after the acquisition date. Accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting recorded goodwill. Additional disclosures are also required. In April 2009, the FASB issued guidance for accounting for assets acquired and liabilities assumed in a business combination that arise from contingencies. Both the December 2007 revision and the April 2009 guidance were effective on January 1, 2009 for all new business combinations. Because we had no business combinations in progress at January 1, 2009, adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary were issued in December 2007 by the FASB. Specifically, the standards clarified that a noncontrolling interest in a subsidiary (sometimes called a minority interest) is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements, but separate from the parent's equity. It requires that the amount of consolidated net income attributable to the noncontrolling interest be clearly identified and presented on the face of the consolidated income statement. It also clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, a parent must recognize a gain or loss in net income when a subsidiary is deconsolidated, based on the fair value of the noncontrolling equity investment on the deconsolidation date. Additional disclosures are required that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. In January 2009, the FASB ratified implementation questions regarding the new accounting standards for noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Both the new accounting standards and the implementation questions were effective January 1, 2009 and must be applied prospectively, except for the presentation and disclosure requirements which must be applied retrospectively for all periods presented in consolidated financial statements. Adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting and reporting standards for fair value measurements were issued in September 2006 by the FASB. The standards define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. The standards do not require any new fair value measurements but may require some entities to change their measurement practices. We adopted these standards effective January 1, 2008 with respect to financial assets and liabilities and effective January 1, 2009 with respect to nonfinancial assets and liabilities. Adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows.

Application guidance to address fair value measurements for purposes of lease classification or measurement in accounting for leases was issued in February 2008 by the FASB. This guidance removes certain leasing transactions from the scope of fair value accounting and adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows.

Guidance for determining the fair value of a financial asset when the market for that asset is not active was issued by the FASB in October 2008. It clarifies the application of fair value measurements in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This guidance was effective upon issuance, including prior periods for which financial statements had not been issued, and any revisions resulting from a change in the valuation technique or its

Index

Notes to Consolidated Financial Statements (Unaudited)

application were required to be accounted for as a change in accounting estimate. Application of this new guidance did not cause us to change our fair value valuation techniques for assets and liabilities.

The fair value disclosures are presented in Note 11.

An employer's disclosures about plan assets of defined benefit pension or other postretirement plans were expanded in December 2008 by the FASB. Additional disclosures about investment policies and strategies, the reporting of fair value by asset category and other information about fair value measurements is required. This was effective January 1, 2009 and early application is permitted. Upon initial application, these new disclosures are not required for earlier periods that are presented for comparative purposes. We will expand disclosures in our Annual Report on Form 10-K for the year ending December 31, 2009; however, the adoption of this standard is not expected to have an impact on our consolidated results of operations, financial position or cash flows.

Not Yet Adopted

Measuring liabilities at fair value, a FASB accounting standards update, was issued in August 2009. This update provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. In such circumstances, an entity is required to measure fair value that uses (1) the quoted price of the identical liability when traded as an asset, or (2) quoted prices for similar liabilities or similar liabilities when traded as assets, or (3) another valuation technique consistent with the fair value measurement principles such as an income approach or a market approach. The new update for measuring liabilities at fair value is effective for the first reporting period (including interim periods) beginning after August 27, 2009 and is not expected to have a significant effect on our consolidated results of operations, financial position or cash flows.

Variable interest accounting standards were amended by the FASB in June 2009. The new accounting standards replace the existing quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity. In addition, the concept of qualifying special-purpose entities has been eliminated and therefore, will now be evaluated for consolidation in accordance with the applicable consolidation guidance. Ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity are also required. The amended variable interest accounting standard requires reconsideration for determining whether an entity is a variable interest entity when changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lack the power from voting rights or similar rights to direct the activities of the entity. Enhanced disclosures are required for any enterprise that holds a variable interest in a variable interest entity. Application will be prospective beginning in the first quarter of 2010, and for all interim and annual periods thereafter. Earlier application is prohibited. We are currently evaluating the provisions of this statement.

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include volumes in their reserve base from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices.

- Permit companies to disclose their probable and possible reserves on a voluntary basis. Under current rules, proved reserves are the only reserves allowed in the disclosures.

- Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

- Replace the existing "certainty" test for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" test.

- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company's overall reserve estimation process. Additionally, disclosures regarding internal controls surrounding reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

- Require separate disclosure of reserves in foreign countries if they represent more than 15 percent of total proved reserves, based on barrels of oil equivalents.

Index

Notes to Consolidated Financial Statements (Unaudited)

We expect to begin complying with the disclosure requirements in our Annual Report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The FASB issued an exposure draft in September 2009 which aligns the FASB's reporting requirements with the above SEC reporting requirements. The exposure draft also addresses the impact of changes in the SEC's rules and definitions on accounting for oil and gas producing activities. Similar to the SEC requirements, the exposure draft requirements would be effective for periods ending on or after December 31, 2009. We are currently in the process of evaluating the new requirements by the SEC and awaiting the final standard from the FASB.

3. Income per Common Share

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

	Three Months Ended September 30,			
	2009		2008	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 392	$ 392	$ 1,992	$ 1,992
Discontinued operations	21	21	72	72
Net income	$ 413	$ 413	$ 2,064	$ 2,064
Weighted average common shares outstanding	709	709	707	707
Effect of dilutive securities	-	2	-	4
Weighted average common shares, including dilutive effect	709	711	707	711
Per share:				
Income from continuing operations	$ 0.55	$ 0.55	$ 2.82	$ 2.80
Discontinued operations	$ 0.03	$ 0.03	$ 0.10	$ 0.10
Net income	$ 0.58	$ 0.58	$ 2.92	$ 2.90

	Nine Months Ended September 30,			
	2009		2008	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 985	$ 985	$ 3,433	$ 3,433
Discontinued operations	123	123	136	136

Net income	$	1,108	$	1,108	$	3,569	$	3,569
Weighted average common shares outstanding		709		709		710		710
Effect of dilutive securities		-		2		-		4
Weighted average common shares, including								
dilutive effect		709		711		710		714
Per share:								
Income from continuing operations	$	1.39	$	1.39	$	4.84	$	4.81
Discontinued operations	$	0.17	$	0.17	$	0.19	$	0.19
Net income	$	1.56	$	1.56	$	5.03	$	5.00

The per share calculations above exclude 11 million stock options for the third quarter and 10 million stock options for the first nine months of 2009, as they were antidilutive. Excluded in the third quarter and the first nine months of 2008 were 6 million and 5 million stock options.

8

Index

Notes to Consolidated Financial Statements (Unaudited)

4. Dispositions

During 2009, we have disposed of our exploration and production businesses in Ireland and certain producing assets in the Permian Basin of New Mexico and Texas. At September 30, 2009, agreements are pending to dispose of our exploration and production business in Gabon and certain assets under development in Angola. These dispositions all relate to our Exploration and Production ("E&P") segment. Our Irish and Gabonese exploration and production businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Assets and liabilities related to the Gabonese business are classified as held for sale in the consolidated balance sheet as of September 30, 2009.

Discontinued operations - Revenues and pretax income associated with our discontinued Irish and Gabonese operations are shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2009	2008	2009	2008
Revenues applicable to discontinued operations	$65	$144	$188	$342
Pretax income from discontinued operations	$48	$109	$98	$202

Net assets held for sale - As of September 30, 2009, assets and liabilities held for sale, which primarily represented our operated interests in Gabon, are shown in the following table:

(In millions)	
Other current assets	$10
Other noncurrent assets	46
Total assets	56
Other current liabilities	12
Deferred credits and other liabilities	17
Total liabilities	29
Net assets held for sale	$27

Pending Gabon disposition - In August 2009, we entered into an agreement to sell our operated fields offshore Gabon for $282 million, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We expect to close this transaction in the fourth quarter of 2009.

Pending Angola disposition - In July 2009, we entered into an agreement to sell an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We will retain a 10 percent outside-operated interest in Block 32. As of September 30, 2009, the book value being sold was $481 million. We expect to close the transaction by year end 2009, subject to government and regulatory approvals.

Permian Basin disposition - In June 2009, we closed sales of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded.

Ireland dispositions - In April 2009, we closed the sale of our operated properties in Ireland for net proceeds of $84 million, after adjusting for cash held by the sold subsidiary. A $158 million pretax gain on the sale was recorded. As a result of this sale, we terminated our pension plan in Ireland, incurring a charge of $18 million.

In June 2009 we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. Total proceeds will range between $235 million and $400 million, subject to the timing of first commercial gas at Corrib and closing adjustments. The fair value of the consideration for this asset was $311 million, which was less than its book value. A $154 million impairment of the held for sale asset was recognized in discontinued operations in the second quarter of 2009 (see Note 11). At closing on July 30, 2009, the initial $100 million payment plus closing adjustments was received. Additional proceeds of $135 million to $300 million will be received on the earlier of first commercial gas or December 31, 2012.

Index

Notes to Consolidated Financial Statements (Unaudited)

Existing guarantees of our subsidiaries' performance issued to Irish government entities will remain in place after the sales until the purchasers issue similar guarantees to replace them. The guarantees, related to asset retirement obligations and natural gas production levels, have been indemnified by the purchasers. Our maximum potential undiscounted payments under these guarantees are $160 million.

5. Segment Information

We have four reportable operating segments. Each of these segments is organized and managed based upon the nature of the products and services they offer.

1) Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis;

2) Oil Sands Mining ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and by-products;

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

4) 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.

As discussed in Note 4, our Irish and Gabonese businesses have been reported as discontinued operations. Segment information for all presented periods excludes amounts for these operations.

	Three Months Ended September 30, 2009				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$1,816	$130	$12,387	$15	$14,348
Intersegment (a)	148	37	8	-	193
Related parties	15	-	12	-	27
Segment revenues	1,979	167	12,407	15	14,568
Elimination of intersegment revenues	(148)	(37)	(8)	-	(193)
Loss on U.K. natural gas contracts(b)	(13)	-	-	-	(13)
Total revenues	$1,818	$130	$12,399	$15	$14,362
Segment income	$491	$25	$158	$13	$687
Income from equity method investments(c)	40	-	14	21	75
Depreciation, depletion and amortization (d)	427	26	167	1	621
Income tax provision (d)	297	7	119	12	435
Capital expenditures (e)	516	267	634	-	1,417

(a) Management believes intersegment transactions were conducted under terms comparable to those with unrelated parties.

(b) The U.K. natural gas contracts expired in September 2009.

(c) Our investment in Pilot Travel Centers LLC, which was reported in our RM&T segment, was sold in the fourth quarter of 2008.

(d) Differences between segment totals and our financial statement 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 reconciliation below.

(e) Differences between segment totals and our financial statement totals represent amounts related to corporate administrative activities.

Index

Notes to Consolidated Financial Statements (Unaudited)

Index

	Three Months Ended September 30, 2008				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$3,439	$532	$18,139	$24	$22,134
Intersegment (a)	278	68	1	-	347
Related parties	11	-	626	-	637
Segment revenues	3,728	600	18,766	24	23,118
Elimination of intersegment revenues	(278)	(68)	(1)	-	(347)
Gain on U.K. natural gas contracts(b)	198	-	-	-	198
Total revenues	$3,648	$532	$18,765	$24	$22,969
Segment income	$869	$288	$771	$65	$1,993
Income from equity method investments(c)	65	-	115	90	270
Depreciation, depletion and amortization (d)	389	37	148	1	575
Income tax provision(d)	947	98	464	34	1,543
Capital expenditures (e)	686	271	765	3	1,725

	Nine Months Ended September 30, 2009				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$4,952	$353	$32,099	$33	$37,437
Intersegment (a)	390	91	25	-	506
Related parties	44	-	24	-	68
Segment revenues	5,386	444	32,148	33	38,011
Elimination of intersegment revenues	(390)	(91)	(25)	-	(506)
Gain on U.K. natural gas contracts(b)	72	-	-	-	72
Total revenues	$5,068	$353	$32,123	$33	$37,577
Segment income	$782	$3	$482	$53	$1,320
Income from equity method investments(c)	77	-	16	91	184
Depreciation, depletion and amortization (d)	1,391	97	476	3	1,967
Income tax provision (benefit)(d)	910	(1)	329	27	1,265
Capital expenditures (e)	1,490	834	2,007	1	4,332

	Nine Months Ended September 30, 2008				
(In millions)	E&P	OSM	RM&T	IG	Total
Revenues:					
Customer	$9,244	$631	$50,739	$64	$60,678
Intersegment (a)	663	184	203	-	1,050
Related parties	40	-	1,825	-	1,865
Segment revenues	9,947	815	52,767	64	63,593
Elimination of intersegment revenues	(663)	(184)	(203)	-	(1,050)
Loss on U.K. natural gas contracts(b)	(37)	-	-	-	(37)

Total revenues	$9,247	$631	$52,564	$64	$62,506
Segment income	$2,316	$158	$854	$266	$3,594
Income from equity method investments(c)	204	-	186	345	735
Depreciation, depletion and amortization (d)	933	104	446	3	1,486
Income tax provision (d)	2,459	53	527	118	3,157
Capital expenditures (e)	2,281	781	1,978	4	5,044

11

Index

Notes to Consolidated Financial Statements (Unaudited)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2009	2008	2009	2008
Segment income	$687	$1,993	$1,320	$3,594
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(159)	(178)	(299)	(253)
Foreign currency remeasurement of taxes	(114)	76	(180)	111
Gain (loss) on U.K. natural gas contracts	(7)	101	37	(19)
Gain (loss) on disposal of assets	(15)	-	107	-
Discontinued operations	21	72	123	136
Net income	$413	$2,064	$1,108	$3,569

The following reconciles total revenues to sales and other operating revenues (including consumer excise taxes) as reported in the consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2009	2008	2009	2008
Total revenues	$14,362	$22,969	$37,577	$62,506
Less: Sales to related parties	27	637	68	1,865
Sales and other operating revenues (including consumer excise taxes)	$14,335	$22,332	$37,509	$60,641

6. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2009	2008	2009	2008
Service cost	$36	$37	$4	$5
Interest cost	42	40	11	11
Expected return on plan assets	(41)	(42)	-	-
Amortization:				
– prior service cost (credit)	4	3	(1)	(2)
– actuarial loss (gain)	8	8	(2)	-
Net periodic benefit cost	$49	$46	$12	$14

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2009	2008	2009	2008

Service cost	$	108	$	110	$	13	$	14
Interest cost		126		120		31		33
Expected return on plan assets		(121)		(126)		-		-
Amortization:								
– prior service cost (credit)		11		10		(4)		(6)
– actuarial loss (gain)		24		23		(4)		1
– net settlement/curtailment loss(a)		18		-		-		-
Net periodic benefit cost	$	166	$	137	$	36	$	42

(a) The curtailment and settlement is related to our discontinued operations in Ireland, as discussed in Note 4. Pension expense relatedto Ireland was not material in any period presented.

12

Index

Notes to Consolidated Financial Statements (Unaudited)

During the first nine months of 2009, we made contributions of $326 million to our funded pension plans. We expect to make additional contributions up to an estimated $7 million to our funded pension plans over the remainder of 2009. Current benefit payments related to unfunded pension and other postretirement benefit plans were $11 million and $25 million during the first nine months of 2009.

7. Income Taxes

The following is an analysis of the effective income tax rates for the periods presented:

	Nine Months Ended September 30,	
	2009	2008
Statutory U.S. income tax rate	35 %	35 %
Foreign taxes in excess of federal statutory rate	25	11
State and local income taxes, net of federal income tax effects	1	1
Other tax effects	-	(1)
Effective income tax rate	61 %	46 %

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The change in mix of liquid hydrocarbon and natural gas sales in 2009 from 2008 resulted in more income in jurisdictions with high tax rates. Beginning in the third quarter of 2009, we are crediting certain foreign taxes that were previously treated as deductible for U.S. tax purposes. We continue to assess the realizability of our deferred tax assets. Our assessments include estimates of our expected future taxable income and assumptions about matters that are dependent on future events. These future events include, but are not limited to, future operating and financial conditions. The 2009 effective tax rate increased due to a change in judgment about the realizability of a portion our deferred tax asset related to U.S. foreign tax credits generated during the year. These changes, as well as unfavorable foreign currency remeasurement effects, contributed to the increase in the effective income tax rate in the first nine months of 2009 as compared to the same period in 2008.

We are continuously undergoing examination of our U.S. federal income tax returns by the Internal Revenue Service. Such audits have been completed through the 2005 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities. As of September 30, 2009, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated.

United States (a)	2001 - 2008
Canada	2000 - 2008
Equatorial Guinea	2006 - 2008
Libya	2006 - 2008
Norway	2007 - 2008
United Kingdom	2007 - 2008

(a) Includes federal and state jurisdictions.

Index

Notes to Consolidated Financial Statements (Unaudited)

8. Comprehensive Income

The following sets forth comprehensive income for the periods indicated:

(In millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income	$413	$2,064	$1,108	$3,569
Other comprehensive income, net of taxes:				
Defined benefit postretirement plans	9	22	27	2
Derivatives	15	(12)	11	(8)
Other	-	(14)	1	(19)
Comprehensive income	$437	$2,060	$1,147	$3,544

9. Inventories

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

(In millions)	September 30, 2009	December 31, 2008
Liquid hydrocarbons, natural gas and bitumen	$ 1,462	$ 1,376
Refined products and merchandise	1,841	1,797
Supplies and sundry items	377	334
Inventories, at cost	$ 3,680	$ 3,507

10. Property, Plant and Equipment

Exploratory well costs capitalized greater than one year after completion of drilling were $371 million as of September 30, 2009, an increase of $317 million from December 31, 2008. Our Angola Block 32 exploration project is now in this category because exploratory drilling ceased in the third quarter of 2008. The $327 million of suspended costs for this project relate to 16 successful wells that have been drilled since 2002 in this license area. We plan to drill an additional exploration well in the fourth quarter of 2009. As discussed in Note 4, we have agreed to sell an undivided 20 percent outside-operated interest in this Angola Block 32.

In addition, an exploration well drilled for $20 million in early 2008 on the Southwest Foinaven prospect in the U.K. Atlantic Margin was added in the first quarter of 2009. It is being evaluated for combined development in conjunction with nearby prospects. For the North Sea Gudrun field, $24 million was removed since engineering and design efforts commenced on its development during the second quarter of 2009.

14

Notes to Consolidated Financial Statements (Unaudited)

11. Fair Value Measurements

Fair Values - Recurring

The following table presents the assets (liabilities) accounted for at fair value on a recurring basis as of September 30, 2009 and December 31, 2008:

	September 30, 2009			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative Instruments:				
Commodity	$27	$2	$(5)	$24
Interest rate	-	-	3	3
Foreign currency	-	3	1	4
Total derivative instruments	27	5	(1)	31
Other assets	2	-	-	2
Total at fair value	$29	$5	$(1)	$33

	December 31, 2008			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative Instruments:				
Commodity	$107	$6	$(55)	$58
Interest rate	-	-	29	29
Foreign currency	-	(75)	-	(75)
Total derivative instruments	107	(69)	(26)	12
Other assets	2	-	-	2
Total at fair value	$109	$(69)	$(26)	$14

Deposits of $25 million and $121 million in broker accounts covered by master netting agreements are netted against the values to arrive at the fair values of commodity derivatives as of September 30, 2009 and December 31, 2008. Derivatives in Level 1 are exchange-traded contracts for crude oil, natural gas, refined products and ethanol measured at fair value with a market approach using the close-of-day settlement prices for the market. Derivatives in Level 2 are measured at fair value with a market approach using broker quotes or third-party pricing services, which have been corroborated with data from active markets. Level 3 derivatives are measured at fair value using either a market or income approach. Generally at least one input is unobservable, such as the use of an internally generated model or an external data source.

Commodity derivatives in Level 3 at September 30, 2009 include crude oil options related to sales of Canadian synthetic crude oil. The crude oil options, which expire December 2009, are measured at fair value using a Black-Scholes option pricing model, an income approach that utilizes prices from an active market and market volatility calculated by a third-party service. The two U.K. natural gas sales contracts accounted for as derivative instruments which were previously included in Level 3 expired in September 2009.

Also in Level 3 are commodity derivatives intended to manage price risk related to acquisition of ethanol for blending and light products fixed priced sales contracts. The fair value of these derivatives is measured using quoted market prices adjusted for broker market assessments.

The fair value of interest rate swaps is measured using broker quotes or quotes from a reporting service which are not corroborated with data from an active market; therefore these inputs are classified as Level 3. The fair value of the foreign currency options are measured using an option pricing model and Level 3 inputs.

The following is a reconciliation of the net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy for the three and nine months ended September 30, 2009:

Index

Notes to Consolidated Financial Statements (Unaudited)

(In millions)	Three Months Ended September 30, 2009
Beginning balance	$ (29)
Total realized and unrealized losses:	
Included in net income	19
Purchases, sales, issuances and settlements, net	9
Ending balance	$ (1)

(In millions)	Nine Months Ended September 30, 2009
Beginning balance	$ (26)
Total realized and unrealized losses:	
Included in net income	63
Purchases, sales, issuances and settlements, net	(38)
Ending balance	$ (1)

Net income for the third quarter and first nine months of 2009 included unrealized gains of $4 million and unrealized losses of $20 million related to instruments held at September 30, 2009. See Note 12 for the income statement impacts of our derivative instruments.

Fair Values - Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ -	$ -	$ 5	$ 15
Long-lived assets held for sale	-	-	311	154

Several long-lived assets held for use were evaluated for impairment in the second and third quarters of 2009 due to reductions in estimated reserves and declining natural gas prices. The fair values of the assets were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs. In the second quarter, an impairment was recorded for one natural gas field in East Texas. No impairments were recorded in the third quarter of 2009.

The impairment charge recorded on assets held for sale in the second quarter of 2009 related to the sale of the Corrib natural gas development offshore Ireland and was based on a fair value of anticipated sale proceeds (see Note 4). Sales proceeds included $100 million at closing plus proceeds of $135 million to $300 million to be received on the earlier of first commercial gas or December 31, 2012. The minimum amount due of $135 million is payable no later than December 31, 2012. The fair value of the total proceeds was measured using an income method that incorporated a probability-weighted approach with respect to timing of first commercial gas and an associated sliding scale on the amount of corresponding consideration specified in the sales agreement: the longer it takes to achieve first gas, the lower the amount of the consideration. Because a portion of the proceeds is variable in timing and amount depending upon timing of first commercial gas, the inputs to the fair value calculation were classified as Level 3 inputs.

At closing on July 30, 2009, the subsidiary that held the Corrib assets was deconsolidated, the initial $100 million payment, plus closing adjustments, was received and a $198 million long-term receivable was recorded for the fair value of the remaining proceeds. The fair value of this portion of the proceeds was measured as discussed above and therefore used Level 3 inputs. The amount ultimately collected could differ from the recorded long-term receivable.

Index

Notes to Consolidated Financial Statements (Unaudited)

Fair Values - Reported

The following table summarizes financial instruments, excluding the derivative financial instruments, and their reported fair value by individual balance sheet line item at September 30, 2009 and December 31, 2008:

	September 30, 2009		December 31, 2008	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Receivables from United States Steel, including current portion	$ 491	$ 477	$ 438	$ 492
Other noncurrent assets(a)	514	376	260	91
Total financial assets	1,005	853	698	583
Financial liabilities				
Long-term debt, including current portion(b)	8,913	8,337	5,683	6,854
Deferred credits and other liabilities(c)	61	62	55	55
Total financial liabilities	$ 8,974	$ 8,399	$ 5,738	$ 6,909

(a) Includes cost method investments, miscellaneous long-term receivables or deposits and restricted cash, of which there was $108 million at September 30, 2009.

(b) Excludes capital leases.

(c) Includes long-term liabilities related to contract terminations.

Our current assets and liabilities accounts include financial instruments, the most significant of which are trade accounts receivable and payable. We believe the carrying values of our current assets and liabilities approximate fair value, with the exception of the current portion of receivables from United States Steel and the current portion of our long-term debt, which is reported above. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The fair value of the receivables from United States Steel is measured using an income approach that discounts the future expected payments over the remaining term of the obligations. Because this asset is not publicly-traded and not easily transferable, a hypothetical market based upon United States Steel’s borrowing rate curve is assumed and the majority of inputs to the calculation are Level 3. The industrial revenue bonds are to be redeemed on or before December 31, 2011.

The majority of our restricted cash represents cash accounts that earn interest or will be held for a short time; therefore, the balance approximates fair value. Other financial instruments included in other noncurrent assets include cost method investments and miscellaneous long-term receivables or deposits. Fair value for the cost method investments is measured using an income approach. Estimated future cash flows, obtained from the partially owned companies, are discounted at an appropriate discount rate to obtain the fair value. We may adjust the companies' estimates based upon current market conditions. Long-term receivables, deposits and long-term liabilities are measured using an income approach. The expected timing of payments is scheduled and then discounted using a rate deemed appropriate. The long-term receivable related to the sale of our Corrib asset was recorded at fair value in the third quarter of 2009, as discussed above.

Over 90 percent of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions is used to measure the fair value of such debt. Because these quotes cannot be independently verified to the market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

12. Derivatives

We may use derivatives to manage our exposure to commodity price risk, interest rate risk and foreign currency risk. Derivative instruments are recorded at fair value. Derivative instruments on our consolidated balance sheet are reported on a net basis by brokerage firm for commodities, as permitted by master netting agreements. For further information regarding the fair value measurement of derivative instruments see Note 11. The following table presents

Index

Notes to Consolidated Financial Statements (Unaudited)

the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of September 30, 2009:

(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$2	$-	$2	Other current assets
Fair Value Hedges				
Interest rate	5	(2)	3	Other noncurrent assets
Total Designated Hedges	7	(2)	5	
Not Designated as Hedges				
Foreign currency	3	-	3	Other current assets
Commodity	202	(3)	199	Other current assets
Total Not Designated as Hedges	205	(3)	202	
Total	$212	$(5)	$207	

(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ -	$ (1)	$ (1)	Other current liabilities
Fair Value Hedges				
Commodity	-	(3)	(3)	Other current liabilities
Total Designated Hedges	-	(4)	(4)	
Not Designated as Hedges				
Commodity	1	(198)	(197)	Other current liabilities
Total Not Designated as Hedges	1	(198)	(197)	
Total	$ 1	$ (202)	$ (201)	

Derivatives Designated as Cash Flow Hedges

We also use foreign currency forwards and options to hedge anticipated transactions, primarily expenditures for capital projects, in certain foreign currencies and designate them cash flow hedges. In the third quarter of 2009, hedge accounting was discontinued prospectively for Kroner and Euro foreign currency forwards when it was determined that they were no longer highly effective hedges. The contracts remain in place for reporting as derivatives not designated as hedges and prospective changes in the fair value of the derivative will be recognized in net interest and financing costs. Ineffectiveness on these hedges of $3 million was recorded as a gain to net interest and other financing costs in the third quarter of 2009. As of September 30, 2009, the following foreign currency forwards and options designated as cash flow hedges were outstanding:

(In millions)	Period

		Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards:			
Dollar (Canada)	October 2009 - February 2010	$ 159	1.075 (a)

(a) U.S. dollar to foreign currency.

(In millions)	Period	Notional Amount	Weighted Average Exercise Price
Foreign Currency Options:			
Dollar (Canada)	October 2009 - March 2010	$ 84	1.053 (a)

((a) U.S. dollar to foreign currency.

We may use interest rate derivative instruments to manage the market risk of interest rate movements on anticipated borrowings. No such derivatives were outstanding at September 30, 2009. In recent past transactions, such

Index

Notes to Consolidated Financial Statements (Unaudited)

derivatives have been outstanding for a period of less than one month.

For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion of cash flow hedges is recognized in net interest and financing costs as it occurs. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

Approximately $2 million in losses are expected to be reclassified from accumulated other comprehensive income ("AOCI") over the next 12 months. The ineffective portion of currently outstanding cash flow hedges was $2 million loss in the third quarter of 2009.

The following table summarizes the pretax effect of derivative instruments designated as hedges of cash flows in other comprehensive income:

	Gain (Loss) in OCI	
(In millions)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Foreign currency	$19	$37
Interest rate	$-	$(15)

The following table summarizes the pretax effect of AOCI reclasses related to derivative instruments designated as hedges of cash flows in our consolidated statement of income:

		Gain (Loss) reclassified from AOCI into Net Income	
(In millions)	Income Statement Location	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Foreign currency	Discontinued operations	$-	$1
Foreign currency	Depreciation, depletion and amortization	$1	$1
Interest rate	Net interest and other financing costs	$(1)	$(2)

Derivatives Designated as Fair Value Hedges

We use interest rate swaps to manage the mix of fixed and floating interest rate debt in our portfolio. As of September 30, 2009, we had multiple interest rate swap agreements with a total notional amount of $1.35 billion at a weighted-average, LIBOR-based, floating rate of 4.38 percent. For such derivatives designated as hedges of fair value, changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

We use commodity derivative instruments to manage the price risk for natural gas that is purchased to be marketed with our own natural gas production. These are also designated as fair value hedges. As of September 30, 2009, commodity derivative instruments for a weighted average 5,000 mcf ("thousand cubic feet") were outstanding for the period October 2009 through March 2010.

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statement of income for the three months and nine months ended September 30, 2009:

Index

Notes to Consolidated Financial Statements (Unaudited)

(In millions)	Income Statement Location	Gain (Loss) Three Months Ended September 30, 200	Gain (Loss) Nine Months Ended September 30, 2009
Derivative			
Commodity	Sales and other operating revenues	$(4)	$(14)
Interest rate	Net interest and other financing costs	26	(3)
		22	(17)
Hedged Item			
Commodity	Sales and other operating revenues	4	14
Long-term debt	Net interest and other financing costs	(26)	3
		(22)	17

The interest rate swaps have no hedge ineffectiveness. Hedge ineffectiveness related to the commodity derivatives is less than $1 million year-to-date September 30, 2009.

Derivatives not Designated as Hedges

Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income. Some derivative instruments not designated as hedges may be classified as trading activities, for which all related effects are recognized in net income and are classified as other income.

The two U.K. natural gas sales contracts accounted for as derivative instruments expired in September 2009.

Crude oil options entered by Western Oil Sands Inc. ("Western") to protect against price decreases on a portion of future sales of synthetic crude oil were not designated as hedges upon our acquisition of Western in October 2007. In the first quarter of 2009, we sold derivative instruments which effectively offset the open put options for the remainder of 2009. All of these options expire in December 2009. The following table summarizes the put and call options outstanding at September 30, 2009:

Option Contract Volumes (Barrels per day)	
Put options purchased	20,000
Put options sold	20,000
Call options sold	15,000
Average Exercise Price (Dollars per barrel)	
Put options	$50.50
Call options	$90.50

We use commodity derivative instruments to manage price risk on inventories and natural gas held in storage before it is sold. We also use derivative instruments to manage price risk related to fixed price sales of refined products, the acquisition of foreign-sourced crude oil, the acquisition of feedstocks used in the refining process and the acquisition of ethanol for blending with refined products. The following table summarizes volumes related to our net open positions as of September 30, 2009:

	Buy/(Sell)
Crude oil (million barrels)	(2.9)
Refined products (million barrels)	0.5
Natural gas (billion cubic feet)	
Price	(2.8)
Basis	(1.6)

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statement of income for the three months and nine months ended September 30, 2009:

20

Index

Notes to Consolidated Financial Statements (Unaudited)

		Gain (Loss)	
(In millions)	Income Statement Location	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Commodity	Sales and other operating revenues	$(11)	$80
Commodity	Cost of revenues	(17)	(59)
Commodity	Other income	4	7
		$(24)	$28

Contingent Credit Features

Our derivative instruments contain no significant contingent credit features.

Concentrations of Credit Risk

All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

13. Debt

At September 30, 2009, we had no borrowings against our revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

On February 17, 2009, we issued $700 million aggregate principal amount of senior notes bearing interest at 6.5 percent with a maturity date of February 15, 2014 and $800 million aggregate principal amount of senior notes bearing interest at 7.5 percent with a maturity date of February 15, 2019. Interest on both issues is payable semi-annually beginning August 15, 2009.

14. Stock-Based Compensation Plans

The following table presents a summary of stock option award and restricted stock award activity for the nine months ended September 30, 2009:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2008	13,841,748	$37.59	2,049,255	$47.72
Granted (a)	4,970,500	27.62	249,721	24.70
Options Exercised/Stock Vested	(108,414)	19.90	(628,020)	46.02
Canceled	(203,892)	48.53	(82,147)	43.95
Outstanding at September 30, 2009	18,499,942	$34.89	1,588,809	$44.97

(a) The weighted average grant date fair value of stock option awards granted was $7.67 per share.

15. Commitments and Contingencies

We are 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. The ultimate resolution of these contingencies could, individually or in the aggregate, be material to our consolidated financial statements. However, management believes that we will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably. Certain of our commitments are discussed below.

Litigation – We settled a number of lawsuits pertaining to methyl tertiary-butyl ether (“MTBE”) in 2008. Presently, we are a defendant, along with other refining companies, in 27 cases arising in four states alleging damages for MTBE contamination. Like the cases that were settled in 2008, 12 of the remaining cases are consolidated in a

Index

Notes to Consolidated Financial Statements (Unaudited)

multi-district litigation (“MDL”) in the Southern District of New York for pretrial proceedings. Fourteen of the remaining cases have been filed in state courts (Nassau and Suffolk Counties, New York), some being re-filed after being dismissed from the MDL. These 12 MDL cases and 14 New York state court cases allege damages to water supply wells, similar to the damages claimed in the cases settled in 2008. In the other remaining case, the New Jersey Department of Environmental Protection is seeking natural resources damages allegedly resulting from contamination of groundwater by MTBE. This is the only MTBE contamination case in which we are a defendant and natural resources damages are sought. We are vigorously defending these cases. We, along with a number of other defendants, have engaged in settlement discussions related to the majority of the cases in which we are a defendant. We do not expect our share of liability, if any, for the remaining cases to significantly impact our consolidated results of operations, financial position or cash flows. We voluntarily discontinued producing MTBE in 2002.

We are currently a party to one qui tam case, which alleges that Marathon and other defendants violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids for federal and Indian leases. A qui tam action is an action in which the relator files suit on behalf of himself as well as the federal government. The case currently pending is U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al. It is primarily a gas valuation case. Marathon has reached a settlement with the Relator and the U.S. Department of Justice (“DOJ”) which will be finalized after the Indian Tribes review and approve the settlement terms. Such settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

A lawsuit filed in the U.S. District Court for the Southern District of West Virginia alleged that our Catlettsburg, Kentucky, refinery distributed contaminated gasoline to wholesalers and retailers for a period prior to August 2003, causing permanent damage to storage tanks, dispensers and related equipment, resulting in lost profits, business disruption and personal and real property damages. Following the incident, we conducted remediation operations at affected facilities and there was no permanent damage to wholesaler and retailer equipment. Class action certification was granted in August 2007. A settlement of the case was approved by the court on March 18, 2009, payment has been made and the case has been dismissed with prejudice. The settlement did not significantly impact our consolidated results of operations, financial position or cash flows.

Contractual commitments – At September 30, 2009, Marathon’s contract commitments to acquire property, plant and equipment were $3,245 million.

16. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
(In millions)	2009	2008
Net cash provided from operating activities included:		
Interest paid (net of amounts capitalized)	$26	$85
Income taxes paid to taxing authorities	1,398	2,458
Short term debt, net:		

Commercial paper - issuances	$897	$46,693
- repayments	(897)	(45,405)
Noncash investing and financing activities:		
Capital lease and sale-leaseback financing obligations	$73	$49

Index

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

We are a global integrated energy company with significant operations in the U.S., Canada, Africa and Europe. Our operations are organized into four reportable segments:

- w Exploration and Production ("E&P") which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- w Oil Sands Mining ("OSM") which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and by-products.
- w Refining, Marketing & Transportation ("RM&T") which refines, markets and transports crude oil and petroleum products, primarily in the Midwest, upper Great Plains, Gulf Coast and southeastern regions of the United States.
- w Integrated Gas ("IG") which 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.

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," "may," "shou 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 forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2008 Annual Report on Form 10-K.

Activities related to discontinued operations in Gabon and Ireland have been excluded from segment results and operating statistics.

Overview and Outlook

Exploration and Production ("E&P")

Production

Net liquid hydrocarbon and natural gas sales averaged 366 and 396 thousand barrels of oil equivalent per day ("mboepd") during the third quarter and first nine months of 2009 compared to 367 and 357 mboepd during the third quarter and first nine months of 2008. Sales increases in the first nine months of 2009 over the same period of 2008 primarily reflect the impact of liquid hydrocarbon production from the Alvheim/Vilje development offshore Norway which commenced production in mid-2008 and natural gas sales in Equatorial Guinea.

We continue to make progress on well completions at the Droshky development in the Gulf of Mexico on Green Canyon Block 244. Work is under way to tie back to the third-party operated Bullwinkle platform. First production is targeted for mid-2010. We hold a 100 percent operated working interest and an 81 percent net revenue interest in Droshky.

In September 2009, the Volund field offshore Norway produced first oil. This is the second major field tied to our Alvheim floating production, storage and offloading (“FPSO”) vessel. While we expect our net share of the field’s peak oil production to be 16,000 bpd, the timing of future production is subject to available processing capacity on the Alvheim FPSO. The first Volund well is functioning as a swing producer to the FPSO until there is some natural decline in the Alvheim field production. We hold a 65 percent operated interest in the Volund field.

Also offshore Norway, our partners announced the Marihone discovery, which is the first of five prospects near the Alvheim FPSO with tie back potential. The Marihone oil discovery is located in license PL340 about 12 miles south of the Volund and Alvheim fields. We hold a 65 percent operated working interest in Marihone.

We hold approximately 335,000 acres over the Bakken Shale play in North Dakota. We currently have three rigs running in our Bakken program and plan to add a fourth rig in the fourth quarter of 2009. Net production from Bakken in the third quarter of 2009 amounted to approximately 11 mboepd compared to 7 mboepd in the same quarter of 2008.

Index

Exploration

During the third quarter of 2009, we announced the Tebe discovery on Block 31 offshore Angola. We hold a 10 percent outside-operated interest in Block 31 and a 30 percent outside-operated interest in Block 32, pending the sale of two-thirds of our Block 32 interest as discussed below.

During the second quarter of 2009, we were awarded all 16 blocks bid in the Central Gulf of Mexico Lease Sale No. 208 conducted by the Minerals Management Service. Ten blocks are 100 percent Marathon, and the remaining six blocks were bid with partners, for a total of $62 million. We have acquired a total of 59 new leases from lease sales held 2007 through 2009.

In the second quarter of 2009, we were awarded a 49 percent interest and will serve as operator in the Kumawa Block offshore Indonesia, our third Indonesian offshore exploration block. The Kumawa Block encompasses 1.24 million acres.

The above discussions include forward-looking statements with respect to the timing and levels of future production and anticipated future drilling activity. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, 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 foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Divestitures

During 2009, we have disposed of our exploration and production businesses in Ireland and certain producing assets in the Permian Basin of New Mexico and Texas. At September 30, 2009, agreements are pending to dispose of our exploration and production business in Gabon and certain assets under development in Angola. Our Irish and Gabonese exploration and production businesses have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Assets and liabilities related to the Gabonese business are classified as held for sale in the consolidated balance sheet as of September 30, 2009.

In August 2009, we entered into an agreement to sell our operated fields offshore Gabon for $282 million, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We expect to close the transaction by year-end 2009.

In July 2009, we entered into an agreement to sell an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion, excluding any purchase price adjustments at closing, with an effective date of January 1, 2009. We will retain a 10 percent outside-operated interest in Block 32. We expect to close the transaction by year-end 2009, subject to government and regulatory approvals.

In June 2009, we closed the sales of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded. Net production from these operations averaged 8,150 barrels of oil equivalent per day (“boepd”) in the first quarter of 2009. Our net proved reserves associated with these assets as of December 31, 2008, were 14 million barrels of oil equivalent (“mmboe”).

In April 2009, we closed the sale of our operated properties in Ireland for net proceeds of $84 million, after adjusting for cash held by the sold subsidiary. A $158 million pretax gain on the sale was recorded. Net production from these operations averaged 5,000 boepd in the first quarter of 2009. Our net proved reserves associated with these assets as of December 31, 2008, were 6 million barrels of oil equivalent (“mmboe”). As a result of this sale, we terminated our pension plan in Ireland, incurring a charge of $18 million which reduced the gain on sale.

In June 2009 we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. Total proceeds will range between $235 million and $400 million, subject to the timing of first commercial gas at Corrib and closing adjustments. The fair value of the consideration for this asset was $311 million, which was less than its book value. A $154 million impairment of the held for sale asset was recognized in discontinued operations in the second quarter of 2009 (see Note 11 and Note 4). At closing on July 30, 2009, the initial $100 million payment plus closing adjustments was received. Additional proceeds of $135 million to $300 million will be received on the earlier of first commercial gas or December 31, 2012.

The above discussions include forward-looking statements with respect to pending divestitures. The divestitures could be adversely affected by customary closing conditions or affected by the inability to obtain or delay in obtaining necessary government and third-party approvals. The divestiture in Gabon could be further affected by consultation

Index

with the Gabonese government. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining ("OSM")

Our bitumen production was 27 thousand barrels per day ("mbpd") in the third quarter and 26 mbpd in the first nine months of 2009.

The Athabasca Oil Sands Project ("AOSP") Phase 1 expansion is on track and anticipated to begin mining operations in the second half of 2010, and upgrader operations in late 2010 or early 2011.

In October, the Government of Canada and Government of Alberta jointly announced their intent to partially fund AOSP's Quest Carbon Capture and Storage ("Quest CCS") project. Under the terms of their letters of intent, the Government of Alberta would contribute 745 million Canadian dollars and the Government of Canada would provide 120 million Canadian dollars toward the project's development. A final investment decision on the Quest CCS project will be made at a later date, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as a final joint venture partner agreement. Marathon has a 20 percent interest in AOSP.

In the second quarter of 2009, the operator of AOSP offered three additional leases to the other joint venture partners for the Muskeg River Mine. Terms of the transaction were as agreed in the original 1999 AOSP Joint Venture Agreement. We elected to participate in these leases and our net proved reserves increased 168 million barrels.

The above discussion includes forward-looking statements with respect to the start of operations of the AOSP Phase 1 expansion. Factors that could affect the project are transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals and other risks customarily associated with construction projects. The foregoing forward-looking statements may be further affected by commissioning and start-up risks associated with proto-type equipment and new technology.

Refining, Marketing and Transportation ("RM&T")

Our total refinery throughputs were 4 percent higher in the third quarter of 2009 compared to the third quarter of 2008, but were relatively flat for the nine-month periods of the same years. Crude oil refined increased 7 percent in the third quarter of 2009. Lower throughputs in 2008 resulted primarily from weather-related events. Planned major maintenance activities were completed at our Canton, Ohio; Catlettsburg, Kentucky; Robinson, Illinois, and Garyville, Louisiana, refineries in the first nine months of 2009. In the first nine months of 2008, major maintenance activities occurred at our Detroit, Michigan; Garyville and Robinson refineries.

Ethanol volumes sold in blended gasoline increased to an average of 62 mbpd for the third quarter of 2009, an 8 percent increase over the same period of 2008. For the first nine months of 2009 we blended an average of 59 mbpd, or 15 percent more ethanol than in the same period of 2008. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

Third quarter 2009 Speedway SuperAmerica LLC ("SSA") same store gasoline sales volume increased 3 percent when compared to the third quarter of 2008, while same store merchandise sales increased by 12 percent for the same period.

As of October 31, 2009, the expansion of our Garyville, Louisiana refinery is approximately 98 percent complete with an on-schedule startup expected late in the fourth quarter 2009. This expansion will increase the Garyville refinery's crude oil refining capacity by 180,000 bpd, improving scale efficiencies and feedstock flexibility. We now forecast that the project will cost between \$3.8 billion and \$3.9 billion. In early January 2010, we plan to commence an extended turnaround at the existing base refinery in Garyville. The entire facility (base and expansion) is expected to reach full refining capacity by the second quarter of 2010.

Construction activities continue on the heavy oil upgrading and expansion project at our Detroit refinery with completion expected in the last half of 2012.

The above discussion includes forward-looking statements with respect to the Garyville and Detroit refinery expansion projects. Factors that could affect those projects include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals, and other risks customarily associated with construction projects. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Integrated Gas ("IG")

Our share of LNG sales worldwide totaled 6,372 metric tonnes per day ("mtpd") for the third quarter of 2009 compared to 6,048 mtpd in the third quarter of 2008 and 6,583 mtpd in the first nine months of 2009 compared to 6,453

Index

mtpd in the first nine months of 2008. These LNG sales volumes include both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska are conducted through a consolidated subsidiary. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

We continue to invest in the development of new technologies to create value and supply new energy sources. In the first nine months of 2009, we recorded costs of approximately $45 million related to natural gas technology research, including our GTFTM technology. Similar spending in the same period of 2008 was $59 million.

Market Conditions

Exploration and Production

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices continue to be volatile in 2009, with the following table listing benchmark crude oil and natural gas price averages for the third quarter and first nine months of 2009 and 2008 to illustrate the volatility:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2009	2008	2009	2008
West Texas Intermediate ("WTI") crude oil (Dollars per barrel)	$68.24	$118.22	$57.32	$113.52
Brent crude oil (Dollars per barrel)	$68.08	$115.09	$57.32	$111.11
Henry Hub natural gas (Dollars per mmbtu)(a)	$3.39	$10.25	$3.93	$9.74

(a) First-of-month price index per million British thermal units.

On average, crude oil prices in 2009 were lower than in 2008. Crude oil prices declined rapidly to lows around $40 per barrel in February 2009 from a high of over $140 per barrel in July 2008. By September 2009 prices had increased to near $70 per barrel.

Our domestic crude oil production is on average heavier and higher in sulfur content than light sweet WTI. Heavier and higher sulfur crude oil (commonly referred to as heavy sour crude oil) typically sells at a discount to light sweet crude oil. Our international crude oil production is relatively sweet and is generally priced in relation to the Brent crude oil benchmark.

Natural gas prices on average were also lower in 2009 than in 2008. Our natural gas sales in Alaska are subject to term contracts. Our other major natural gas-producing regions are Europe and Equatorial Guinea, where large portions of our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. As we sell larger quantities of natural gas from these regions, to the extent that these fixed prices are lower than prevailing prices, our reported average natural gas price realizations may decrease.

Our worldwide E&P revenues during the third quarter and first nine months of 2009 were 47 and 46 percent lower than in the same periods of 2008, with the majority of the revenue decreases tied to these decreases in average commodity prices.

Oil Sands Mining

OSM segment revenues correlate with prevailing market prices for the various qualities of synthetic crude oil and vacuum gas oil we produce. Approximately two-thirds of our normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mine or upgrader.

The operating cost structure of the oil sands mining operations is predominantly fixed, and therefore many of the costs incurred in times of full operation continue during production downtime. Per unit costs are sensitive to production rates. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company ("AECO") natural gas sales index and crude prices respectively.

The table below shows benchmark prices that impacted both our revenues and variable costs for the third quarter and first nine months of 2009 and 2008:

Index

Benchmark	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
WTI crude oil (Dollars per barrel)	$68.24	$118.22	$57.32	$113.52
Western Canadian Select (Dollars per barrel)(a)	$58.05	$100.22	$48.47	$93.16
AECO natural gas sales index (Canadian dollars per gigajoule)(b)	$2.78	$7.45	$3.59	$8.19

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.

(b) Monthly average of Alberta Energy Company day ahead index.

Excluding the impact of derivatives, our OSM segment revenues for the third quarter and first nine months of 2009 were lower than for the same periods of 2008, reflecting the impact of lower price realizations for synthetic crude oil and vacuum gas oil sales. Realizations were 45 percent lower in the third quarter and 51 percent lower for the first nine months of 2009, compared to the same periods of 2008.

Refining, Marketing and Transportation

RM&T segment income depends largely on our refining and wholesale marketing gross margin, refinery throughputs, retail marketing gross margins for gasoline, distillates and merchandise, and the profitability of our pipeline transportation operations.

Our refining and wholesale marketing gross margin is the difference between the prices of refined products sold and the costs of crude oil and other charge and blendstocks refined, including the costs to transport these inputs to our refineries, the costs of purchased products and manufacturing expenses, including depreciation. The crack spread is a measure of the difference between spot market prices at major trading locations for refined products and crude oil, commonly used by the industry as an indicator of the impact of price on the refining margin. Crack spreads can fluctuate significantly, particularly when prices of refined products do not move in the same relationship as the cost of crude oil. As a performance benchmark and a comparison with other industry participants, we calculate Midwest (Chicago) and U.S. Gulf Coast crack spreads that we feel most closely track our operations and slate of products. Posted Light Louisiana Sweet (“LLS”) prices and a 6-3-2-1 ratio of products (6 barrels of crude oil refined into 3 barrels of gasoline, 2 barrels of distillate and 1 barrel of residual fuel) are used for the crack spread calculation. The following table lists calculated average crack spreads for the Midwest and Gulf Coast markets and the sweet/sour differential for the third quarter and first nine months of 2009 and 2008:

(Dollars per barrel)	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
Chicago LLS 6-3-2-1 crack spread	$3.93	$7.81	$4.20	$3.59
U.S. Gulf Coast LLS 6-3-2-1 crack spread	$2.50	$6.32	$2.99	$3.26
Sweet/Sour differential(a)	$5.64	$11.38	$5.62	$12.64

(a)

Calculated using the following mix of crude types: 15% Arab Light, 20% Kuwait, 10% Maya, 15% Western Canadian Select, 40% Mars.

In addition to the market changes indicated by the crack spreads, our refining and wholesale marketing gross margin is impacted by factors such as:

- the types of crude oil and other charge and blendstocks processed,
- the selling prices realized for refined products,
- the impact of commodity derivative instruments used to manage price risk,
- the cost of products purchased for resale, and
- changes in manufacturing costs, which include depreciation.

Our refineries can process significant amounts of sour crude oil which may enhance our margin compared to what the change in the relevant crack spread indicators would suggest, as sour crude oil typically can be purchased at a discount to sweet crude oil. The amount of this discount can and does vary significantly and can therefore have a significant impact on our refining and wholesale marketing gross margin. Manufacturing costs are primarily driven by the cost of energy used by our refineries and the level of maintenance activities.

Index

Our refining and wholesale marketing gross margin for the third quarter and first nine months of 2009 was 70 percent and 29 percent lower when compared to the same periods of 2008, consistent with changes in crack spreads, with the significantly reduced sweet/sour differential adding to the unfavorable impact.

Integrated Gas

Our integrated gas strategy is to link stranded natural gas resources with areas where a supply gap is emerging due to declining production and growing demand. Our integrated gas operations include marketing and transportation of products manufactured from natural gas, such as LNG and methanol, primarily in the U.S., Europe and West Africa.

Our most significant LNG investment is our 60 percent ownership in a production facility in Equatorial Guinea, which sells LNG under a long-term contract at prices tied to Henry Hub natural gas prices.

We own a 45 percent interest in a methanol plant located in Equatorial Guinea through our investment in Atlantic Methanol Production Company LLC (“AMPCO”). AMPCO’s plant capacity is 1.1 million tones per annum, or 3 percent of 2008 world demand. Also included in the financial results of the Integrated Gas segment are costs associated with ongoing development of integrated gas projects, including natural gas technology research.

The impact of lower Henry Hub prices in the third quarter and first nine months of 2009 compared to the same periods of 2008 can be seen in decreased earnings from the LNG production facility although the production levels increased over the same periods. Our methanol realizations were also down during the third quarter, in line with global methanol prices.

Management's Discussion and Analysis of Results of Operations

Consolidated Results of Operations

Revenues are summarized by segment in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2009	2008	2009	2008
E&P	$1,979	$3,728	$5,386	$9,947
OSM	167	600	444	815
RM&T	12,407	18,766	32,148	52,767
IG	15	24	33	64
Segment revenues	14,568	23,118	38,011	63,593
Elimination of intersegment revenues	(193)	(347)	(506)	(1,050)
Gain (loss) on U.K. natural gas contracts	(13)	198	72	(37)
Total revenues	$14,362	$22,969	$37,577	$62,506

Items included in both revenues and costs:				
Consumer excise taxes on petroleum products and merchandise	$1,258	$1,273	$3,658	$3,784

E&P segment revenues decreased $1,749 million in the third quarter and $4,561 million in the first nine months of 2009 from the comparable prior-year periods. The decreases were primarily a result of lower liquid hydrocarbon and natural gas price realizations. Liquid hydrocarbon realizations averaged $64.12 per barrel in the third quarter and $53.62 in the first nine months of 2009 compared to $110.69 and $104.05 in the same periods of 2008, while natural gas realizations averaged $2.20 per mcf in the third quarter and $2.42 in the first nine months of 2009 compared to $5.09 and $4.88 in the same periods of 2008.

Net sales volumes during the quarter were flat when compared to the same period last year, averaging 366 mboepd in 2009 and 367 mboepd in 2008. Net sales volumes for the first nine months of 2009 were 11 percent higher than the comparable prior-year period, primarily impacted by liquid hydrocarbon sales volumes from the Alvheim/Vilje field which commenced production in mid-2008. This increase in sales volumes partially offsets the impact of liquid hydrocarbon and natural gas realization decreases previously discussed.

See Supplemental Statistics for information regarding net sales volumes and average realizations by geographic area.

Index

Excluded from E&P segment revenues were losses of $13 million and gains of $198 million for the third quarters of 2009 and 2008 related to natural gas sales contracts in the U.K. accounted for as derivative instruments. For the first nine months of 2009 and 2008 gains of $72 million and losses of $37 million are excluded from E&P segment revenues. These derivative instruments expired in September 2009.

OSM segment revenues decreased $433 million in the third quarter and $371 million in the first nine months of 2009 compared to the same periods of 2008. The crude oil options we entered in the first quarter of 2009 effectively offset the open put options for the remainder of 2009. As a result, the impact of derivatives in 2009 was insignificant compared to pretax derivative gains of $255 million in the third quarter and losses of $131 million in the first nine months of 2008. Net synthetic crude sales for the third quarter of 2009 were 33 mbpd at an average realized price of $62.08 per barrel compared to 32 mbpd at an average realized price of $113.42 in the same period last year.

See Note 12 to the consolidated financial statements for additional information about derivative instruments.

RM&T segment revenues decreased $6,359 million in the third quarter of 2009 and $20,619 million in the first nine months of 2009 from the comparable prior-year periods. The third quarter and the nine month decreases compared to prior year primarily reflect lower refined product selling prices.

Sales to related parties decreased as a result of the sale of our interest in Pilot Travel Centers LLC (“PTC”) during the fourth quarter of 2008.

Income from equity method investments decreased $195 million in the third quarter of 2009 and $551 million in the first nine months of 2009 from the comparable prior-year periods. Lower commodity prices negatively impacted the earnings of many of our equity investees. The sale of our equity method investment in PTC during the fourth quarter of 2008 also contributed to the decrease.

Net gain on disposal of assets in the first nine months of 2009 primarily represents the sale of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas.

Cost of revenues decreased $6,015 million and $21,262 million in the third quarter and first nine months of 2009 from the comparable prior-year periods. These decreases resulted primarily from decreases in acquisition costs of crude oil, refinery charge and blendstocks and purchased refined products in the RM&T segment.

Depreciation, depletion and amortization (“DD&A”) increased in third quarter and first nine months of 2009 from the comparable prior-year periods. The DD&A increase is primarily due to the commencement of production from the Alvheim/Vilje and Neptune developments in mid-year 2008 combined with the impact of a reduction in the Neptune field reserves in the first quarter of 2009.

Selling, general and administrative expenses decreased in the third quarter and first nine months of 2009 from the comparable prior-year periods primarily due to lower compensation expenses.

Exploration expenses were $55 million and $181 million in the third quarter and first nine months of 2009, including expenses related to dry wells of $10 million and $22 million. Exploration expenses were $108 million and $367 million in the third quarter and first nine months of 2008, including expenses related to dry wells of $24 million and $106 million. Other exploration expenses incurred in the first nine months of 2008 related to the acquisition of seismic data in Indonesia and the evaluation of Canadian in-situ oil sands leases.

Provision for income taxes decreased $1,011 million and $1,400 million in the third quarter and first nine months of 2009 from the comparable periods of 2008. Changes in our provision for income taxes are driven by the decrease in income before income taxes and changes in our effective income tax rate. The following is an analysis of the effective income tax rates for the first nine months of 2009 and 2008:

	Nine Months Ended September 30,			
	2009		2008	
Statutory U.S. income tax rate	35	%	35	%
Foreign taxes in excess of federal statutory rate	25		11	
State and local income taxes, net of federal income tax effects	1		1	
Other tax effects	-		(1	)
Effective income tax rate	61	%	46	%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The change in mix of liquid hydrocarbon and natural gas sales in 2009 from 2008 resulted in more income in jurisdictions with high tax rates. Beginning in the third quarter of 2009, we are crediting certain foreign taxes that were previously treated as deductible for U.S. tax purposes. We continue to assess the realizability of our deferred tax assets. Our assessments include estimates of our expected future taxable income and assumptions about matters that are dependent on future

Index

events. These future events include, but are not limited to, future operating and financial conditions. The 2009 effective tax rate increased due to a change in judgment about the realizability of a portion our deferred tax asset related to U.S. foreign tax credits generated during the year. These changes, as well as unfavorable foreign currency remeasurement effects, contributed to the increase in the effective income tax rate in the first nine months of 2009 as compared to the same period in 2008.

Discontinued operations reflect the current year disposal of our E&P businesses in Ireland and Gabon (see Note 4) and the historical results of those operations, net of tax, for all periods presented.

Segment Results

Segment income is summarized in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2009	2008	2009	2008
E&P				
United States	$ 32	$ 285	$ (61)	$ 888
International	459	584	843	1,428
E&P segment	491	869	782	2,316
OSM	25	288	3	158
RM&T	158	771	482	854
IG	13	65	53	266
Segment income	687	1,993	1,320	3,594
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(159)	(178)	(299)	(253)
Foreign currency remeasurement of deferred taxes	(114)	76	(180)	111
Gain (loss) on U.K. natural gas contracts	(7)	101	37	(19)
Gain on disposal of assets	(15)	-	107	-
Discontinued operations	21	72	123	136
Net income	$ 413	$ 2,064	$ 1,108	$ 3,569

United States E&P income decreased $253 million and $949 million in the third quarter and first nine months of 2009 compared to the same periods of 2008. Revenues decreased approximately 49 percent in the third quarter and 55 percent in the first nine months of 2009, primarily as a result of lower realizations on both liquid hydrocarbons and natural gas. Liquid hydrocarbon sales were flat in the third quarter and first nine months of 2009 compared to the same periods of 2008. Natural gas sales for both periods were lower than in the same periods of 2008 primarily due to disposition of our Permian assets, declining production in Alaska and increased storage activity in Alaska. Offsetting the losses were lower operating expenses in 2009, primarily as a result of lower ad valorem and severance taxes. Other expenses, totaling $63 million for the nine-month period, included rig cancellation fees and partial impairment of a natural gas field in east Texas and a Gulf of Mexico pipeline investment.

International E&P income decreased $125 million and $585 million in the third quarter and first nine months of 2009 compared to the same periods of 2008. The decreases were primarily due to over 40 percent lower liquid hydrocarbon realizations for the third quarter and first nine months of 2009 compared to the same periods of 2008. Liquid hydrocarbon sales from the Alvheim/Vilje development which commenced production in June 2008 had a favorable income impact, partially offset by the DD&A related to this production. Lower exploration expenses had a positive income impact in both periods.

OSM segment income decreased $263 million and $155 million in the third quarter and first nine months of 2009. After-tax derivative gains of $190 million and losses of $98 million were included in reported income for the third quarter and first nine months of 2008. Derivative gains or losses in 2009 were not significant. Exclusive of the derivative effects, OSM segment income reflects decreases in both periods driven by lower synthetic crude realizations, partially offset by lower energy and blendstock costs. DD&A in the third quarter of 2009 was lower than in the same period of 2008 primarily as a result of the reserves added in the second quarter of 2009.

RM&T segment income decreased by $613 million and $372 million in the third quarter and first nine months of 2009 compared to the same periods of 2008. The decreases were primarily due to our refining and wholesale marketing

Index

gross margin which averaged 7.62 cents per gallon in the third quarter of 2009 and 8.08 cents per gallon in the first nine months of 2009 compared to 25.19 cents per gallon and 11.37 cents per gallon in the comparable periods of 2008. The gross margin decrease was consistent with the declines in crack spreads as reflected in the relevant market indicators in the Midwest (Chicago) and Gulf Coast and the substantial reduction in the sweet-sour differential. However, these unfavorable impacts were partially offset by lower manufacturing and other expenses in the third quarter and first nine months of 2009 as compared to the same periods of 2008 primarily due to lower energy costs.

Our refining and wholesale marketing gross margin also included pretax derivative losses of $17 million and $64 million in the third quarter and first nine months of 2009 compared to gains of $156 million and losses of $151 million in the third quarter and first nine months of 2008.

SSA's total light products and merchandise margin declined $10 million in the third quarter and improved $26 million in the first nine months of 2009 compared to the same periods of 2008. Increased merchandise margins, resulting from higher same store sales were the primary factor contributing to the improved margins in the first nine months of 2009.

IG segment income decreased $52 million in the third quarter of 2009 and $213 million in the first nine months of 2009 compared to the same periods of 2008. The decrease was primarily the result of lower price realizations. The LNG sales contract in Equatorial Guinea has a Henry Hub basis so the approximately 67 percent decline in this index had a significant effect on LNG profitability. During the third quarter of 2009 the LNG plant was down for planned maintenance, which was completed in 14 days versus the original 18-day schedule, but higher plant reliability had a positive impact on year-over-year volumes.

Management's Discussion and Analysis of Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities totaled $2,906 million in the first nine months of 2009, compared to $4,807 million in the first nine months of 2008. Cash provided by operating activities decreased primarily due to lower net income, driven primarily by lower commodity prices.

Net cash used in investing activities totaled $3,764 million in the first nine months of 2009, compared to $4,800 million in the first nine months of 2008. Our long-term projects, such as the Garyville refinery major expansion, Expansion 1 of the AOSP, exploration offshore Angola and in the Gulf of Mexico, and development of Alvheim, the Bakken Shale resource play and the Droshky prospect, were the most significant investing activities in both periods. For further information regarding capital expenditures by segment, see Supplemental Statistics. In addition, proceeds of $573 million were generated from the sale of assets in 2009.

Net cash provided by financing activities was $926 million in the first nine months of 2009, compared to $302 million in the first nine months of 2008. Sources of cash in the first nine months of 2009 included the issuance of $1.5 billion in senior notes, while $1.0 billion in senior notes were issued in the first nine months of 2008. Uses of cash in the first nine months of 2008 included the repayment of $400 million 6.85 percent notes, the payment and termination of the Marathon Oil Canada Corporation (previously Western Oil Sands Inc.) revolving credit facility, and purchases of common stock. Dividends paid were a significant use of cash in both years.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations and our $3.0 billion committed revolving credit facility. Because of the alternatives available to us, including internally generated cash flow and access to capital markets, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, share repurchase program, dividend payments, defined benefit plan contributions, repayment of debt maturities and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

At September 30, 2009, we had no borrowings against our revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

On February 17, 2009, we issued $700 million aggregate principal amount of senior notes bearing interest at 6.5 percent with a maturity date of February 15, 2014 and $800 million aggregate principal amount of senior notes bearing interest at 7.5 percent with a maturity date of February 15, 2019. Interest on both issues is payable semi-annually beginning August 15, 2009.

On July 26, 2007, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Index

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+.

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 25 percent at September 30, 2009, compared to 22 percent at December 31, 2008. This includes $470 million of debt that is serviced by United States Steel.

(In millions)	September 30, 2009	December 31, 2008
Long-term debt due within one year	$ 105	$ 98
Long-term debt	8,581	7,087
Total debt	$ 8,686	$ 7,185
Cash	$ 1,370	$ 1,285
Trusted funds from revenue bonds	$ -	$ 16
Equity	$ 22,091	$ 21,409
Calculation:		
Total debt	$ 8,686	$ 7,185
Minus cash	1,370	1,285
Minus trusteed funds from revenue bonds	-	16
Total debt minus cash	$ 7,316	$ 5,884
Total debt	8,686	7,185
Plus equity	22,091	21,409
Minus cash	1,370	1,285
Minus trusteed funds from revenue bonds	-	16
Total debt plus equity minus cash	$ 29,407	$ 27,293
Cash-adjusted debt-to-capital ratio	25 %	22 %

Capital Requirements

On October 28, 2009, our Board of Directors declared a dividend of 24 cents per share, payable December 10, 2009, to stockholders of record at the close of business on November 18, 2009.

Since August 2008, we have not made any purchases under the common share repurchase program authorized by our Board of Directors in January 2006.

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. Estimates may differ from actual results. 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. 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, refining and mining 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, 2009, our consolidated contractual cash obligations have increased by $1,848 million from December 31, 2008. Short and long-term debt increased by $1,501 million primarily due to the issuance of $1.5 billion in senior notes as previously discussed. Also, our obligations under crude oil, refinery feedstock, and refined product contracts increased $509 million due mainly to price increases. There have been no other significant changes to our

32

Index

obligations to make future payments under existing contracts subsequent to December 31, 2008. 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, 2008.

Receivable from United States Steel

We remain obligated (primarily or contingently) for $494 million of certain debt and other financial arrangements for which United States Steel Corporation ("United States Steel") has assumed responsibility for repayment (see the USX Separation in Item 1. of our 2008 Annual Report on 10-K). In its Form 10-Q for the nine months ended September 30, 2009, United States Steel management stated that it believes its liquidity will be adequate to satisfy its obligations for the foreseeable future. During the second quarter of 2009, United States Steel undertook certain plans and actions designed to preserve and enhance its liquidity and financial flexibility, including the sale of its common stock and issuance of senior convertible notes due 2014 for net proceeds of approximately $1,496 million. United States Steel's senior unsecured debt ratings are BB by Standard and Poor's Corporation, Ba3 by Moody's Investment Service, Inc. and BBB- by Fitch Ratings.

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 reflected in the prices of our products and services or if demand for our products is lowered because of these additional costs, our 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, operational efficiencies, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil, refined products and feedstocks.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to impact us In April of 2009, the Environmental Protection Agency ("EPA") issued a proposed finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. It is anticipated EPA will finalize this finding later this year. Related to this finding, in September of 2009, the EPA proposed a greenhouse gas emission standard for mobile sources. This standard is expected to be finalized in the spring of 2010. The EPA has also proposed a greenhouse gas emission reporting rule which was signed by the Administrator in September to be effective for calendar year 2010. Further, in May 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454) (commonly referred to as the "Waxman-Markey Bill") which includes a cap and trade system to reduce carbon emissions in the United States. Cap and trade legislation (commonly referred to as the "Kerry-Boxer Bill") has also been introduced into and will be considered by the U.S. Senate.

Adverse impacts to our business if a cap and trade system as in the Waxman-Markey or Kerry-Boxer Bill or some other comprehensive greenhouse gas legislation is enacted or if the EPA finalizes standards for greenhouse gas emissions, include increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances adding costs to the products we produce, and reduced demand for crude oil and certain refined products. The extent and magnitude of such adverse impacts cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We have estimated that we may spend approximately $1 billion over a six-year period that began in 2008 to comply with Mobile Source Air Toxics II ("MSAT II") regulations relating to benzene content in refined products. We have not finalized our strategy or cost estimates to comply with these requirements. Our actual MSAT II expenditures since inception have totaled $198 million through September 30, 2009, with $53 million in the third quarter of 2009. We expect 2009 spending will be approximately $220 million. The cost estimates are forward-looking statements and are subject to change as further work is completed in 2009.

There have been no other significant changes to our environmental matters subsequent to December 31, 2008.

Resolved Matters

The matter of a suit by the State of Colorado's Department of Public Health and Environment alleging violations of storm water requirements was resolved in the third quarter of 2009 with the parties paying a penalty of $280,000 of which our share was $98,000.

A previously disclosed lawsuit brought by the State of New Mexico alleging air pollution violations at our Indian Basin Natural Gas Plant has been settled in principle with the State of New Mexico. The parties are working on a consent order to finalize the settlement. The settlement requires a cash penalty of $450,000 and plant compliance projects and supplemental environmental projects estimated to cost over $5 million. We were the operator and part owner of the plant through June 2009. We are working with the other plant owners to obtain reimbursement for their share of these costs.

Index

The Texas Commission on Environmental Quality ("TCEQ") had issued us a notice of enforcement relating to benzene waste national emission standards for hazardous air pollutants inspection at our Texas City refinery. We resolved this matter in the second quarter of 2009 with an order including a civil penalty of $46,000. We are also required to continue to operate an ambient air monitoring system for an additional six months as a supplemental environmental project in settlement of this enforcement action brought by the TCEQ.

The matter of an EPA notice of violation for oil spills at the Catlettsburg Refinery in 2004 and 2008 was resolved in the second quarter of 2009 through an order and civil penalty of $118,000.

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.

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.

Effective January 1, 2009, we adopted accounting and reporting standards for fair value measurements with respect to nonfinancial assets and liabilities. These standards define fair value, establish a fair value framework for measuring fair value and expand disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques to measure fair value. See Note 11 of the consolidated financial statements for disclosures regarding our fair value measurements.

There have been no other changes to our critical accounting estimates subsequent to December 31, 2008.

Accounting Standards Not Yet Adopted

Measuring liabilities at fair value, a FASB accounting standards update, was issued in August 2009. This update provides clarification for circumstances in which a quoted price in an active market for the identical liability is not available. In such circumstances, an entity is required to measure fair value that uses (1) the quoted price of the identical liability when traded as an asset, or (2) quoted prices for similar liabilities or similar liabilities when traded as assets, or (3) another valuation technique consistent with the fair value measurement principles such as an income approach or a market approach. The new update for measuring liabilities at fair value is effective for the first reporting period (including interim periods) beginning after August 27, 2009 and is not expected to have a significant effect on our consolidated results of operations, financial position or cash flows.

Variable interest accounting standards were amended by the FASB in June 2009. The new accounting standards replace the existing quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity. In addition, the concept of qualifying special-purpose entities has been eliminated and therefore, will now be evaluated for consolidation in accordance with the applicable consolidation guidance. Ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity are also required. The amended variable interest accounting standard requires reconsideration for determining whether an entity is a variable interest entity when changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lack the power from voting rights or similar rights to direct the activities of the entity. Enhanced disclosures are required for any enterprise that holds a variable interest in a variable interest entity. Application will be prospective beginning in the first quarter of 2010, and for all interim and annual periods thereafter. Earlier application is prohibited. We are currently evaluating the provisions of this statement.

Index

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include volumes in their reserve base from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.
- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices.
- Permit companies to disclose their probable and possible reserves on a voluntary basis. Under current rules, proved reserves are the only reserves allowed in the disclosures.
- Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.
- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.
- Replace the existing "certainty" test for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" test.
- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company's overall reserve estimation process. Additionally, disclosures regarding internal controls surrounding reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.
- Require separate disclosure of reserves in foreign countries if they represent more than 15 percent of total proved reserves, based on barrels of oil equivalents.

We expect to begin complying with the disclosure requirements in our Annual Report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The FASB issued an exposure draft in September 2009 which aligns the FASB’s reporting requirements with the above SEC reporting requirements. The exposure draft also addresses the impact of changes in the SEC’s rules and definitions on accounting for oil and gas producing activities. Similar to the SEC requirements, the exposure draft requirements would be effective for periods ending on or after December 31, 2009. We are currently in the process of evaluating the new requirements by the SEC and awaiting the final standard from the FASB.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For a detailed discussion of our risk management strategies and our derivative instruments, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our 2008 Annual Report on Form 10-K.

Disclosures about how derivatives are reported in our consolidated financial statements and how the fair values of our derivative instruments are measured may be found in Note 11 and 12 to the consolidated financial 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-15(e) and 15d-15(e) 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 upon 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, 2009, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Index

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Segment Income (Loss)				
Exploration and Production				
United States	$32	$285	$(61)	$888
International	459	584	843	1,428
E&P segment	491	869	782	2,316
Oil Sands Mining	25	288	3	158
Refining, Marketing and Transportation	158	771	482	854
Integrated Gas	13	65	53	266
Segment income	687	1,993	1,320	3,594
Items not allocated to segments, net of income taxes	(274)	71	(212)	(25)
Net income	$413	$2,064	$1,108	$3,569
Capital Expenditures				
Exploration and Production	$516	$686	$1,490	$2,281
Oil Sands Mining	267	271	834	781
Refining, Marketing and Transportation	634	765	2,007	1,978
Integrated Gas	-	3	1	4
Discontinued Operations	3	52	66	106
Corporate	10	9	18	18
Total	$1,430	$1,786	$4,416	$5,168
Exploration Expenses				
United States	$23	$68	$88	$173
International	32	40	93	194
Total	$55	$108	$181	$367

Index

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd)				
United States	63	63	64	63
Europe	76	66	87	43
Africa	83	83	87	86
Total International	159	149	174	129
Worldwide Continuing Operations	222	212	238	192
Discontinued Operations(a)	10	12	6	7
Worldwide	232	224	244	199
Net Natural Gas Sales (mmcfd) (b)				
United States	339	426	376	446
Europe	119	153	143	164
Africa	409	346	427	379
Total International	528	499	570	543
Worldwide Continuing Operations	867	925	946	989
Discontinued Operations(a)	-	3	22	31
Worldwide	867	928	968	1,020
Total Worldwide Sales (mboepd)				
Continuing operations	366	367	396	357
Discontinued operations(a)	10	12	9	12
Worldwide	376	379	405	369
Average Realizations (c)				
Liquid Hydrocarbons (per bbl)				
United States	$ 61.07	$ 106.81	$ 50.19	$ 100.27
Europe	70.58	118.52	60.10	115.15
Africa	60.50	107.47	49.67	101.33
Total International	65.32	112.33	54.88	105.90
Worldwide Continuing Operations	64.12	110.69	53.62	104.05
Discontinued Operations(a)	67.77	123.06	56.27	112.37
Worldwide	$ 64.27	$ 111.33	$ 53.68	$ 104.33
Natural Gas (per mcf)				
United States	$ 3.63	$ 7.70	$ 3.94	$ 7.70
Europe	4.87	8.76	4.89	7.94
Africa(d)	0.25	0.25	0.25	0.25
Total International	1.29	2.86	1.41	2.57
Worldwide Continuing Operations	2.20	5.09	2.42	4.88

Discontinued Operations(a)	-	13.79	8.54	8.98
Worldwide	$ 2.20	$ 5.11	$ 2.56	$ 5.00

(a) Our oil and gas businesses in Ireland (natural gas) and Gabon (liquid hydrocarbons) are treated as discontinued operations in all periods presented.

(b) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd and 2 mmcfd in the third quarters of 2009 and 2008, and 20 mmcfd and 21 mmcfd for the first nine months of 2009 and 2008.

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

(d) Primarily represents a fixed price under long-term contracts with Alba Plant LLC, AMPCO and Equatorial Guinea LNG Holdings Limited ("EGHoldings"), equity method investees. We include our share of Alba Plant LLC's income in our E&P segment and we include our share of AMPCO's and EGHoldings' income in our Integrated Gas segment.

Index

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions, except as noted)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
OSM Operating Statistics				
Net Bitumen Production (mbpd)	27	28	26	25
Net Synthetic Crude Sales (mbpd)	33	32	31	31
Synthetic Crude Average Realization (per bbl)	$62.08	$113.42	$52.02	$106.37
RM&T Operating Statistics				
Refinery Runs (mbpd)				
Crude oil refined	1,019	955	943	941
Other charge and blend stocks	171	189	197	201
Total	1,190	1,144	1,140	1,142
Refined Product Yields (mbpd)				
Gasoline	687	586	655	598
Distillates	330	358	319	336
Propane	23	21	23	22
Feedstocks and special products	75	95	66	104
Heavy fuel oil	22	20	23	24
Asphalt	70	79	70	75
Total	1,207	1,159	1,156	1,159
Refined Products Sales Volumes (mbpd) (e)	1,400	1,357	1,353	1,335
Refining and Wholesale Marketing Gross Margin (per gallon) (f)	$0.0762	$0.2519	$0.0808	$0.1137
Speedway SuperAmerica				
Retail outlets	1,610	1,620	-	-
Gasoline and distillate sales (millions of gallons)	818	796	2,408	2,376
Gasoline and distillate gross margin (per gallon)	$0.1399	$0.1690	$0.1175	$0.1235
Merchandise sales	$842	$764	$2,341	$2,133
Merchandise gross margin	$207	$197	$577	$541
IG Operating Statistics				
Net Sales (mtpd) (g)				
LNG	6,372	6,048	6,583	6,453
Methanol	1,145	757	1,220	1,024

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

(f) Sales revenue less cost of refinery inputs, purchased products and manufacturing expenses, including depreciation.

(g) Includes both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska are conducted through a consolidated subsidiary. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

38

Index

Part II – OTHER INFORMATION

Item 1. Legal Proceedings

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. Certain of these matters are included below. The ultimate resolution of these contingencies could, individually or in the aggregate, be material. However, we believe that we will remain a viable and competitive enterprise even though it is possible that these contingencies could be resolved unfavorably.

MTBE Litigation

We settled a number of lawsuits pertaining to methyl tertiary-butyl ether ("MTBE") in 2008. Presently, we are a defendant, along with other refining companies, in 27 cases arising in four states alleging damages for MTBE contamination. Like the cases that were settled in 2008, 12 of the remaining cases are consolidated in a multi-district litigation ("MDL") in the Southern District of New York for pretrial proceedings. Fourteen of the remaining cases have been filed in state courts (Nassau and Suffolk Counties, New York), some being re-filed after being dismissed from the MDL. These 12 MDL cases and 14 New York state court cases allege damages to water supply wells, similar to the damages claimed in the cases settled in 2008. In the other remaining case, the New Jersey Department of Environmental Protection is seeking natural resources damages allegedly resulting from contamination of groundwater by MTBE. This is the only MTBE contamination case in which we are a defendant and natural resources damages are sought. We are vigorously defending these cases. We, along with a number of other defendants, have engaged in settlement discussions related to the majority of the cases in which we are a defendant. We do not expect our share of liability, if any, for the remaining cases to significantly impact our consolidated results of operations, financial position or cash flows. We voluntarily discontinued producing MTBE in 2002.

Natural Gas Royalty Litigation

We are currently a party to one qui tam case, which alleges that Marathon and other defendants violated the False Claims Act with respect to the reporting and payment of royalties on natural gas and natural gas liquids for federal and Indian leases. A qui tam action is an action in which the relator files suit on behalf of himself as well as the federal government. The case currently pending is U.S. ex rel Harrold E. Wright v. Agip Petroleum Co. et al. It is primarily a gas valuation case. Marathon has reached a settlement with the Relator and the DOJ which will be finalized after the Indian Tribes review and approve the settlement terms. Such settlement is not expected to significantly impact our consolidated results of operations, financial position or cash flows.

Product Contamination Litigation

A lawsuit filed in the U.S. District Court for the Southern District of West Virginia alleged that our Catlettsburg, Kentucky, refinery distributed contaminated gasoline to wholesalers and retailers for a period prior to August 2003, causing permanent damage to storage tanks, dispensers and related equipment, resulting in lost profits, business disruption and personal and real property damages. Following the incident, we conducted remediation operations at affected facilities and there was no permanent damage to wholesaler and retailer equipment. Class action certification was granted in August 2007. A settlement of the case was approved by the court on March 18, 2009, payment has been made and the case has been dismissed with prejudice. The settlement did not significantly impact our consolidated results of operations, financial position or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. See the discussion of such risks and uncertainties under Item 1A. Risk Factors in our 2008 Annual Report on Form 10-K. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

Index

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

Period	column (a) Total Number of Shares Purchased (a)(b)		column (b) Average Price Paid per Share	column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (d)	column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (d)
07/01/09 – 07/31/09	14,659		$30.59	-	$2,080,366,711
08/01/09 – 08/31/09	77,428		$32.81	-	$2,080,366,711
09/01/09 – 09/30/09	49,901	(c)	$31.85	-	$2,080,366,711
Total	141,988		$32.24	-	

(a) 95,112 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 we acquired the minority interest in Marathon Petroleum Company and other businesses from Ashland Inc. (“Ashland”), Ashland shareholders have the right to receive 0.2364 shares of Marathon common stock for each share of Ashland common stock owned as of June 30, 2005 and cash in lieu of fractional based on a value of $52.17 per share. In the third quarter of 2009, we acquired 6 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 46,870 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. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon.

(d) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of September 30, 2009, 66 million split-adjusted common shares had been acquired at a cost of $2,922 million, which includes transaction fees and commissions that are not reported in the table above. No shares have been repurchased under this program since August 2008.

Index

Item 6. Exhibits

The following exhibits are filed as a part of this report:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
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					X	
31.2	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
32.1	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350					X	
32.2	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350					X	
101.INS	XBRL Instance Document						X
101.SCH	XBRL Taxonomy Extension Schema						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase						X
101.LAB	XBRL Taxonomy Extension Label Linkbase						X

Index

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.

November 6, 2009

MARATHON OIL CORPORATION

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