MARATHON OIL CORP
Form 10-Q
August 06, 2010

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 June 30, 2010

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 x No o

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 x No o

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

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

There were 709,668,991 shares of Marathon Oil Corporation common stock outstanding as of July 30, 2010.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended June 30, 2010

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Unless the context otherwise indicates, references in this Form 10-Q to “Marathon,” “we,” “our,” or “us” are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon exerts significant influence by virtue of its ownership interest).

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Part I - Financial Information

Item 1. Financial Statements

MARATHON OIL CORPORATION

Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2010	2009	2010	2009
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$18,417	$13,018	$34,266	$23,174
Sales to related parties	32	21	52	41
Income from equity method investments	101	62	206	109
Net gain on disposal of assets	12	191	825	195
Other income	12	25	45	77
Total revenues and other income	18,574	13,317	35,394	23,596
Costs and expenses:				
Cost of revenues (excludes items below)	14,292	9,760	27,173	17,117
Purchases from related parties	141	110	274	205
Consumer excise taxes	1,308	1,226	2,520	2,400
Depreciation, depletion and amortization	658	683	1,307	1,343
Long-lived asset impairments	33	15	467	15
Selling, general and administrative expenses	336	321	634	612
Other taxes	110	96	225	198
Exploration expenses	125	64	223	126
Total costs and expenses	17,003	12,275	32,823	22,016
Income from operations	1,571	1,042	2,571	1,580
Net interest and other financing costs	(18)	(12)	(48)	(28)
Loss on early extinguishment of debt	(92)	-	(92)	-
Income from continuing operations before income taxes	1,461	1,030	2,431	1,552
Provision for income taxes	752	702	1,265	959
Income from continuing operations	709	328	1,166	593
Discontinued operations	-	85	-	102

Net income	$709	$413	$1,166	$695
Per Share Data				
Basic:				
Income from continuing operations	$1.00	$0.46	$1.64	$0.84
Discontinued operations	$-	$0.12	$-	$0.14
Net income per share	$1.00	$0.58	$1.64	$0.98
Diluted:				
Income from continuing operations	$1.00	$0.46	$1.64	$0.84
Discontinued operations	$-	$0.12	$-	$0.14
Net income per share	$1.00	$0.58	$1.64	$0.98
Dividends paid	$0.25	$0.24	$0.49	$0.48

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

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MARATHON OIL CORPORATION
Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	June 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$2,062	$2,057
Receivables, less allowance for doubtful accounts of $17 and $14	4,974	4,677
Receivables from related parties	54	60
Inventories	3,586	3,622
Other current assets	584	221
Total current assets	11,260	10,637
Equity method investments	1,868	1,970
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $18,310 and $17,185	31,703	32,121
Goodwill	1,383	1,422
Other noncurrent assets	1,282	902
Total assets	$47,496	$47,052
Liabilities		
Current liabilities:		
Accounts payable	$6,790	$6,982
Payables to related parties	42	64
Payroll and benefits payable	312	399
Accrued taxes	1,049	547
Deferred income taxes	462	403
Other current liabilities	546	566
Long-term debt due within one year	101	96
Total current liabilities	9,302	9,057
Long-term debt	7,829	8,436
Deferred income taxes	4,013	4,104
Defined benefit postretirement plan obligations	1,989	2,056
Asset retirement obligations	1,148	1,099
Deferred credits and other liabilities	374	390
Total liabilities	24,655	25,142
Commitments and contingencies		

Stockholders’ Equity		
Preferred stock – zero and 5 million shares issued, zero and 1 million shares outstanding (no par value, 26 million shares authorized)	-	-
Common stock:		
Issued – 770 million and 769 million shares (par value $1 per share, 1.1 billion shares authorized)	770	769
Securities exchangeable into common stock – zero and 5 million shares issued, zero and 1 million shares outstanding (no par value, 29 million authorized)	-	-
Held in treasury, at cost – 61 million shares	(2,687)	(2,706)
Additional paid-in capital	6,754	6,738
Retained earnings	18,859	18,043
Accumulated other comprehensive loss	(855)	(934)
Total stockholders' equity	22,841	21,910
Total liabilities and stockholders' equity	$47,496	$47,052

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

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MARATHON OIL CORPORATION

Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
(In millions)	2010	2009
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$1,166	$695
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on early extinguishment of debt	92	-
Discontinued operations	-	(102)
Deferred income taxes	(114)	338
Depreciation, depletion and amortization	1,307	1,343
Long-lived asset impairments	467	15
Pension and other postretirement benefits, net	101	73
Exploratory dry well costs and unproved property impairments	111	33
Net gain on disposal of assets	(825)	(195)
Equity method investments, net	(26)	11
Changes in:		
Current receivables	(280)	(792)
Inventories	(303)	6
Current accounts payable and accrued liabilities	381	449
All other operating, net	50	102
Net cash provided by continuing operations	2,127	1,976
Net cash provided by discontinued operations	-	61
Net cash provided by operating activities	2,127	2,037
Investing activities:		
Additions to property, plant and equipment	(2,505)	(3,207)
Disposal of assets	1,361	402
Trusteed funds - withdrawals	-	16
Investments - loans and advances	(17)	(10)
Investments - repayments of loans and return of capital	56	45
Investing activities of discontinued operations	-	(66)
All other investing, net	(37)	(86)
Net cash used in investing activities	(1,142)	(2,906)
Financing activities:		
Borrowings	-	1,491
Debt issuance costs	-	(11)
Debt repayments	(625)	(40)
Dividends paid	(350)	(340)
All other financing, net	5	(1)
Net cash provided by (used in) financing activities	(970)	1,099
Effect of exchange rate changes on cash:		
Continuing operations	(10)	(17)
Discontinued operations	-	(2)

Total effect of exchange rate changes on cash	(10)	(19)
Net increase in cash and cash equivalents	5	211
Cash and cash equivalents at beginning of period	2,057	1,285
Cash and cash equivalents at end of period	$2,062	$1,496

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

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MARATHON OIL CORPORATION

Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Net income	$709	$413	$1,166	$695
Other comprehensive income (loss)				
Post-retirement and post-employment plans				
Change in actuarial gain	128	41	158	49
Income tax provision on post-retirement and post-employment plans	(59)	(22)	(83)	(31)
Post-retirement and post-employment plans, net of tax	69	19	75	18
Derivative hedges				
Net unrecognized gain	1	30	3	3
Income tax benefit (provision) on derivatives	-	(4)	1	(7)
Derivative hedges, net of tax	1	26	4	(4)
Foreign currency translation and other				
Unrealized gain	-	(1)	-	1
Income tax provision on foreign currency translation and other	-	1	-	-
Foreign currency translation and other, net of tax	-	-	-	1
Other comprehensive income (loss)	70	45	79	15
Comprehensive income	$779	$458	$1,245	$710

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

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MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, these statements 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 have been made to conform to current year presentation.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Marathon Oil Corporation ("Marathon") 2009 Annual Report on Form 10-K. The results of operations for the quarter and six months ended June 30, 2010 are not necessarily indicative of the results to be expected for the full year.

2. Accounting Standards

Recently Adopted

Variable interest accounting standards were amended by the Financial Accounting Standards Board ("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. 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. Prospective application of this standard in the first quarter of 2010 did not have significant impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 3.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. We adopted all aspects of this standard in the first quarter of 2010, including the gross presentation of the Level 3 activity rollforward, which could have been deferred until 2011. This adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 11.

Oil and Gas Reserve Estimation and Disclosure standards were issued by the FASB in January 2010, which align the FASB's reporting requirements with the Securities and Exchange Commission ("SEC") requirements. Similar to the SEC requirements, the FASB requirements were effective for periods ending on or after December 31, 2009. The SEC introduced a new definition of oil and gas producing activities which allows companies to include volumes in their reserve base from unconventional resources. The FASB also addresses the impact of changes in the SEC's rules and definitions on accounting for oil and gas producing activities. Initial adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The effect on depreciation, depletion and amortization expense in the first quarter of 2010, as compared to prior periods, was not significant.

3. Variable Interest Entities

The Athabasca Oil Sands Project ("AOSP"), in which we hold a 20 percent undivided interest, contracted with a wholly-owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River mine, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $1 million current liability recorded at June 30, 2010. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we are responsible for the portion of the payment related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a VIE. We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of

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Notes to Consolidated Financial Statements (Unaudited)

the total; therefore, the Corridor Pipeline is not consolidated by Marathon. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $838 million as of June 30, 2010. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month's activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

4. Income per Common Share

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

	Three Months Ended June 30,			
	2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$709	$709	$328	$328
Discontinued operations	-	-	85	85
Net income	$709	$709	$413	$413
Weighted average common shares outstanding	710	710	709	709
Effect of dilutive securities	-	2	-	2
Weighted average common shares, including dilutive effect	710	712	709	711
Per share:				
Income from continuing operations	$1.00	$1.00	$0.46	$0.46
Discontinued operations	$-	$-	$0.12	$0.12
Net income	$1.00	$1.00	$0.58	$0.58

	Six Months Ended June 30,			
	2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$1,166	$1,166	$593	$593
Discontinued operations	-	-	102	102
Net income	$1,166	$1,166	$695	$695
Weighted average common shares outstanding	709	709	709	709
Effect of dilutive securities	-	2	-	2
Weighted average common shares, including dilutive effect	709	711	709	711

Per share:				
Income from continuing operations	$1.64	$1.64	$0.84	$0.84
Discontinued operations	$-	$-	$0.14	$0.14
Net income	$1.64	$1.64	$0.98	$0.98

The per share calculations above exclude 12 million stock options and stock appreciation rights for the second quarter and the first six months of 2010, as they were antidilutive. Excluded in the second quarter and the first six months of 2009 were 8 million stock options and stock appreciation rights.

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Notes to Consolidated Financial Statements (Unaudited)

5. Dispositions

Assets Held For Sale

In May 2010, we entered into a non-binding letter of intent to sell our RM&T segment's St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 Speedway SuperAmerica retail outlets, plus related inventories. A final agreement is being negotiated and the sale is anticipated to close by year end 2010. Based on the estimated fair value of the consideration at June 30, 2010, any gain to be recognized at closing is not expected to be significant.

As of June 30, 2010, the Minnesota assets and liabilities held for sale are reported in the consolidated balance sheet as follows:

(In millions)	
Other current assets	$329
Other noncurrent assets	494
Total assets	823
Deferred credits and other liabilities	3
Total liabilities	$3

2010 Disposition

During the first quarter 2010, we closed the sale of a 20 percent outside-operated interest in our E&P segment’s Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale in the amount of $811 million. We retained a 10 percent outside-operated interest in Block 32.

2009 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. Activities related to our operated properties in Ireland had been reported in our Exploration and Production (E&P) segment.

On June 24, 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. An initial $100 million payment was made at closing. Additional fixed proceeds of $135 million will be received on the earlier of first commercial gas or

December 31, 2012. Including contingent consideration, the fair value of $311 million at June 30, 2009, was less than book value. An impairment of $154 million was recognized in the second quarter of 2009 and reported as part of the loss on disposal of discontinued operations.

Existing guarantees of our subsidiaries' performance issued to Irish government entities 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. The fair value of these guarantees is not significant.

In December 2009, we closed the sale of our operated fields offshore Gabon, receiving net proceeds of $269 million, after closing adjustments. A $232 million pretax gain on this disposition was reported in discontinued operations in the fourth quarter of 2009.

Our Irish businesses and our Gabonese businesses, which had been reported in our E&P segment, have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for the three and six months ended June 30, 2009. Revenues, pretax income and the net pretax loss on these dispositions are shown on the table below.

(In millions)	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Revenues applicable to discontinued operations	$43	$121
Pretax income from discontinued operations	20	50
Pretax loss on disposal of discontinued operations	$14	$14

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Notes to Consolidated Financial Statements (Unaudited)

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.

6. 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 vacuum gas oil;

3) Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis; and

4) 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.

As discussed in Note 5, our Irish and Gabonese businesses were sold in 2009 and have been reported as discontinued operations. Segment information for all presented periods of 2009 excludes amounts for these operations.

	Three Months Ended June 30, 2010				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$2,464	$158	$33	$15,762	$18,417
Intersegment (a)	152	21	-	15	188
Related parties	14	-	-	18	32
Segment revenues	2,630	179	33	15,795	18,637
Elimination of intersegment revenues	(152)	(21)	-	(15)	(188)
Total revenues	$2,478	$158	$33	$15,780	$18,449
Segment income (loss)	$432	$(60)	$24	$421	$817
Income from equity method investments	40	-	43	18	101

Depreciation, depletion and amortization (b)	391	16	1	241	649
Income tax provision (benefit)(c)	624	(10)	12	257	883
Capital expenditures (b)(d)	585	243	-	256	1,084

	Three Months Ended June 30, 2009				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$1,830	$126	$7	$11,052	$13,015
Intersegment (a)	123	29	-	8	160
Related parties	14	-	-	7	21
Segment revenues	1,967	155	7	11,067	13,196
Elimination of intersegment revenues	(123)	(29)	-	(8)	(160)
Gain on U.K. natural gas contracts(e)	3	-	-	-	3
Total revenues	$1,847	$126	$7	$11,059	$13,039
Segment income	$208	$2	$13	$165	$388
Income from equity method investments	26	-	28	8	62
Depreciation, depletion and amortization (b)	484	34	1	157	676
Income tax provision(c)	435	-	2	104	541
Capital expenditures (b)(d)	609	281	1	713	1,604

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Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30, 2010				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$4,801	$305	$60	$29,100	$34,266
Intersegment (a)	324	39	-	31	394
Related parties	26	-	-	26	52
Segment revenues	5,151	344	60	29,157	34,712
Elimination of intersegment revenues	(324)	(39)	-	(31)	(394)
Total revenues	$4,827	$305	$60	$29,126	$34,318
Segment income (loss)	$934	$(77)	$68	$184	$1,109
Income from equity method investments	77	-	91	38	206
Depreciation, depletion and amortization (b)	788	39	2	461	1,290
Income tax provision (benefit)(c)	1,162	(17)	35	104	1,284
Capital expenditures (b)(d)	1,188	508	1	566	2,263

	Six Months Ended June 30, 2009				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$3,136	$223	$18	$19,712	$23,089
Intersegment (a)	242	54	-	17	313
Related parties	29	-	-	12	41
Segment revenues	3,407	277	18	19,741	23,443
Elimination of intersegment revenues	(242)	(54)	-	(17)	(313)
Gain on U.K. natural gas contracts(e)	85	-	-	-	85
Total revenues	$3,250	$223	$18	$19,724	$23,215
Segment income (loss)	$291	$(22)	$40	$324	$633
Income from equity method investments	37	-	70	2	109
Depreciation, depletion and amortization (b)	949	71	2	309	1,331
Income tax provision (benefit)(c)	613	(8)	15	210	830
Capital expenditures (b)(d)	974	567	1	1,373	2,915

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

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

(c) 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 the reconciliation below.

(d) Includes accruals.

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

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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 June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Segment income	$817	$388	$1,109	$633
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(62)	(90)	(72)	(140)
Foreign currency remeasurement of income taxes	37	(94)	70	(66)
Gain on dispositions(a)	-	122	449	122
Impairments(b)	(26)	-	(288)	-
Loss on early extinguishment of debt(c)	(57)	-	(57)	-
Deferred income taxes - tax legislation changes(d)	-	-	(45)	-
Gain on U.K. natural gas contracts	-	2	-	44
Discontinued operations	-	85	-	102
Net income	$709	$413	$1,166	$695

(a) Additional information on these gains can be found in Note 5.

(b) Impairments include those based upon fair value measurements discussed in Note 11 and a $15 million pretax writeoff of the remaining portion of the contingent proceeds from the sale of the Corrib natural gas development which was taken based upon new public information regarding the pipeline that would transport gas from the Corrib development.

(c) Additional information on debt retired early can be found in Note 13.

(d) A discussion of the tax legislation changes can be found in Note 8.

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 June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Total revenues	$ 18,449	$ 13,039	$ 34,318	$ 23,215
Less: Sales to related parties	32	21	52	41
Sales and other operating revenues (including consumer excise taxes)	$ 18,417	$ 13,018	$ 34,266	$ 23,174

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2010	2009	2010	2009
Service cost	$ 25	$ 37	$ 4	$ 4
Interest cost	42	42	9	9
Expected return on plan assets	(40)	(40)	-	-
Amortization:				
– prior service cost (credit)	3	4	(1)	(2)
– actuarial loss (gain)	25	10	(1)	(2)
– net settlement/curtailment loss(a)	-	18	-	-
Net periodic benefit cost	$ 55	$ 71	$ 11	$ 9

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Notes to Consolidated Financial Statements (Unaudited)

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2010	2009	2010	2009
Service cost	$ 54	$ 72	$ 9	$ 9
Interest cost	87	84	19	20
Expected return on plan assets	(80)	(80)	-	-
Amortization:				
– prior service cost (credit)	6	7	(3)	(3)
– actuarial loss (gain)	50	16	(1)	(2)
– net settlement/curtailment loss(a)	-	18	-	-
Net periodic benefit cost	$ 117	$ 117	$ 24	$ 24

(a) The curtailment and settlement is related to our discontinued operations in Ireland, as discussed in Note 5. Pension expense related to Ireland was not material in any period presented.

During the first six months of 2010, we made contributions of $12 million to our funded pension plans. We expect to make additional contributions up to an estimated $230 million to our funded pension plans over the remainder of 2010. Current benefit payments related to unfunded pension and other postretirement benefit plans were $13 million and $18 million during the first six months of 2010.

8. Income Taxes

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

	Six Months Ended June 30,	
	2010	2009
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	16	26
State and local income taxes, net of federal income tax effects	-	1
Legislation change	2	-
Other	(1)	-
Effective income tax rate for continuing operations	52 %	62 %

The Patient Protection and Affordable Care Act (“PPACA”) and the Health Care and Education Reconciliation Act of 2010 (“HCERA”), (together, the “Acts”) were signed in to law in March 2010. The “Acts” effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the “MPDIMA”). Under the MPDIMA, the federal subsidy does not reduce our income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Beginning in 2013, under the Acts, our income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. As a result, we have recorded a charge of $45 million in the first quarter of 2010 for the write-off of deferred tax assets to reflect the change in the tax treatment of the federal subsidy.

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 provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in the Corporate and other unallocated items line of the reconciliation shown in Note 6.

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Notes to Consolidated Financial Statements (Unaudited)

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)	June 30, 2010	December 31, 2009
Liquid hydrocarbons, natural gas and bitumen	$1,393	$1,393
Refined products and merchandise	1,825	1,790
Supplies and sundry items	368	439
Inventories	$3,586	$3,622

10. Property, Plant and Equipment

(In millions)	June 30, 2010	December 31, 2009
E&P		
U.S.	$6,044	$6,005
International	4,935	5,522
Total E&P	10,979	11,527
OSM	8,938	8,531
IG	35	34
RM&T	11,613	11,887
Corporate	138	142
Property, plant and equipment	$31,703	$32,121

Exploratory well costs capitalized greater than one year after completion of drilling were $158 million as of June 30, 2010, an increase of $8 million from December 31, 2009.

The offshore Gulf of Mexico Shenandoah appraisal well, located at Walker Ridge Block 52, was added to this category in the first quarter of 2010 at a cost of $28 million. The Shenandoah costs were incurred primarily during 2009. Appraisal drilling for the Shenandoah prospect is in our near-term plans. The results of the appraisal well program will be used to evaluate the commercial viability of the project.

A new, detailed study of the commerciality of the Gardenia well in Equatorial Guinea concluded that development of this area is now uncertain and therefore $20 million in costs associated with this well were written off in the first quarter of 2010. The remaining $10 million of exploration well costs in Equatorial Guinea are associated with the

Corona well which were incurred in 2004. Efforts to develop these reserves continue and we are evaluating both a unitization with existing production facilities and stand-alone development.

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11. Fair Value Measurements

Fair Values - Recurring

The following table presents assets and liabilities accounted for at fair value on a recurring basis as of June 30, 2010 and December 31, 2009 by fair value hierarchy level.

	June 30, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 184	$ 50	$ -	$ 6	240
Interest rate	-	30	-	-	30
Foreign currency	-	-	1	-	1
Derivative instruments, assets	184	80	1	6	271
Derivative instruments, liabilities					
Commodity	$ (160)	$ (1)	$ (4)	$ -	(165)
Foreign currency	-	(1)	-	-	(1)
Derivative instruments, liabilities	(160)	(2)	(4)	-	(166)

	December 31, 2009				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 133	$ 11	$ 12	$ 63	$ 219
Interest rate	-	-	7	-	7
Foreign currency	-	1	2	-	3
Derivative instruments, assets	133	12	21	63	229
Derivative instruments, liabilities					
Commodity	$ (125)	$ (12)	$ (10)	$ -	$ (147)
Interest rate	-	-	(2)	-	(2)
Derivative instruments, liabilities	(125)	(12)	(12)	-	(149)

Commodity 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 price for the market. Commodity derivatives, interest rate derivatives and foreign currency forwards in Level 2 are measured at fair value with a market approach using broker price quotes or prices obtained from third-party services such as Bloomberg L.P. or Platt's, a Division of McGraw-Hill Corporation ("Platt's"), which have been corroborated with data from active markets for similar assets and liabilities. Collateral deposits related to both Level 1 and Level 2 commodity derivatives are in broker accounts covered by master netting agreements.

Commodity derivatives in Level 3 are measured at fair value with a market approach using prices obtained from third-party services such Platt’s and price assessments from other independent brokers. The fair value of foreign currency options is measured using an option pricing model for which the inputs are obtained from a reporting service. Since we are unable to independently verify information from the third-party service providers to active markets, all these measures are considered Level 3.

Interest rate derivatives, formerly in Level 3, are reported in Level 2 beginning second quarter because we now corroborate the interest rates used in the fair value measurement.

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Notes to Consolidated Financial Statements (Unaudited)

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Beginning balance	$8	$9	$9	$(26)
Total realized and unrealized gains (losses):				
Included in net income	20	(33)	19	44
Included in other comprehensive income	2	-	4	-
Transfers to Level 2	(30)	-	(30)	-
Purchases	-	-	2	-
Sales	-	(23)	-	(23)
Issuances	-	-	-	(44)
Settlements	(3)	18	(7)	20
Ending balance	$(3)	$(29)	$(3)	$(29)

Net income for the second quarter and first six months of 2010 included unrealized losses of $2 million and $4 million related to instruments held at June 30, 2010. Net income for second quarter and first six months of 2009 included unrealized losses of $4 million and unrealized gains of $76 million related to instruments held on those dates. See Note 12 for the income statement impacts of our derivative instruments.

Fair Values - Nonrecurring

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

	Three Months Ended June 30,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 2	$ 33	$ 5	$ 15
Long-lived assets held for sale	-	-	311	154

	Six Months Ended June 30,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 146	$ 467	$ 5	$ 15
Long-lived assets held for sale	-	-	311	154

In March 2010, we completed a reservoir study which resulted in a portion of our Powder River Basin field being removed from plans for future development in our E&P segment. The field's fair value was measured at $144 million, using an income approach based upon internal estimates of future production levels, prices and discount rate which are Level 3 inputs. This resulted in an impairment of $423 million.

As a result of changing market conditions, a supply agreement with a major customer was revised in June 2010. An impairment of $28 million was recorded in our RM&T segment for a plant that manufactures maleic anhydride. The fair value was measured using a market approach based upon comparable area land values which are Level 3 inputs.

Several other long-lived assets held for use in our E&P segment were evaluated for impairment in the six months ended June 30, 2010 and the comparable period of 2009 due to reduced drilling expectations, reduction of estimated reserves or 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.

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 5).

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Fair value of anticipated sale proceeds includes (1) $100 million received at closing, (2) $135 million minimum amount due at the earlier of first gas or December 31, 2012, and (3) a range of contingent proceeds subject to the timing of first gas. 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.

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 June 30, 2010 and December 31, 2009:

	June 30, 2010		December 31, 2009	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 23	$ 22	$ 23	$ 22
Other noncurrent assets	575	411	671	499
Total financial assets	598	433	694	521
Financial liabilities				
Long-term debt, including current portion(a)	8,308	7,565	8,754	8,190
Deferred credits and other liabilities	73	74	71	73
Total financial liabilities	$ 8,381	$ 7,639	$ 8,825	$ 8,263

(a) Excludes capital leases.

Our current assets and liabilities accounts include financial instruments, the most significant of which are trade accounts receivables and payables. 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 Corporation ("United States Steel"), which is reported in other current assets above, and the current portion of our long-term debt, which is reported with long-term debt 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 current portion of receivables from United States Steel is reported in other current assets, and the long-term portion is included in other noncurrent assets. 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 receivable 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 January 1, 2012, the tenth anniversary of the USX Separation.

Restricted cash is included in other noncurrent assets. The majority of our restricted cash represent cash accounts that earn interest; therefore, the balance approximates fair value. Fair values of our remaining financial assets included in other noncurrent assets and of our financial liabilities included in deferred credits and other liabilities are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

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.

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Notes to Consolidated Financial Statements (Unaudited)

12. Derivatives

For information regarding the fair value measurement of derivative instruments, see Note 11. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheets as of June 30, 2010, and December 31, 2009.

	June 30, 2010			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ 1	$ -	$ 1	Other current assets
Fair Value Hedges				
Interest rate	30	-	30	Other noncurrent assets
Total Designated Hedges	31	-	31	
Not Designated as Hedges				
Commodity	234	161	73	Other current assets
Total Not Designated as Hedges	234	161	73	
Total	$ 265	$ 161	$ 104	

	June 30, 2010			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$-	$1	$1	Other current liabilities
Total Designated Hedges	-	1	1	
Not Designated as Hedges				
Commodity	-	4	4	Other current liabilities
Total Not Designated as Hedges	-	4	4	
Total	$-	$5	$5	

	December 31, 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	8	3	5	Other noncurrent assets
Total Designated Hedges	10	3	7	

Not Designated as Hedges							
Foreign currency		1		-		1	Other current assets
Commodity		116		104		12	Other current assets
Total Not Designated as Hedges		117		104		13	
Total	$	127	$	107	$	20	

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Notes to Consolidated Financial Statements (Unaudited)

	December 31, 2009			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$-	$-	$-	Other current liabilities
Fair Value Hedges				
Commodity	-	1	1	Other current liabilities
Total Designated Hedges	-	1	1	
Not Designated as Hedges				
Commodity	13	15	2	Other current liabilities
Total Not Designated as Hedges	13	15	2	
Total	$13	$16	$3	

Derivatives Designated as Cash Flow Hedges

As of June 30, 2010, the following foreign currency forwards and options were designated as cash flow hedges.

(In millions)	Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards:			
Dollar (Canada)	July 2010 - October 2010	$ 50	1.049 (a)

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

(In millions)	Period	Notional Amount	Weighted Average Exercise Price
Foreign Currency Options:			
Dollar (Canada)	July 2010 - December 2010	$ 96	1.040 (a)

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

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

	Gain (Loss) in OCI			
	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Foreign currency	$1	$30	$3	$18
Interest rate	-	-	-	(15)

Derivatives Designated as Fair Value Hedges

As of June 30, 2010, we had multiple interest rate swap agreements with a total notional amount of $1,450 million at a weighted-average, LIBOR-based, floating rate of 4.5 percent.

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Notes to Consolidated Financial Statements (Unaudited)

The following table summarizes the pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2010	2009	2010	2009
Derivative					
Interest rate	Net interest and other financing costs	$19	$(29)	$24	$(29)
Hedged Item					
Long-term debt	Net interest and other financing costs	$(19)	$29	$(24)	$29

Derivatives not Designated as Hedges

The largest portion of our June 30, 2010, open commodity derivative contracts not designated as hedges in our E&P and OSM segments are related to 2010 forecasted sales, as shown in the table below.

	Term	Bbls per Day	Weighted Average Swap Price	Benchmark
Crude Oil				
Canada	July 2010 - December 2010	25,000	$82.56	West Texas Intermediate

	Term	Mmbtu per Day(a)	Weighted Average Swap Price	Benchmark
Natural Gas				
U.S. Lower 48	July 2010 - December 2010	80,000	$5.39	CIG Rocky Mountains(b)
U.S. Lower 48	July 2010 - December 2010	30,000	$5.59	NGPL Mid Continent(c)

(a) Million British thermal units.
(b) Colorado Interstate Gas Co. (“CIG”).
(c) Natural Gas Pipeline Co. of America (“NGPL”).

The table below summarizes open commodity derivative contracts of our RM&T segment at June 30, 2010 that are not designated as hedges. These contracts enable us to effectively correlate our commodity price exposure to the relevant market indicators, thereby mitigating fixed price risk.

	Position	Bbls per Day	Weighted Average Price	Benchmark
Crude Oil				
Exchange-traded	Long(a)	119,066	$78.03	CME and IPE Crude(b) (c)
Exchange-traded	Short(a)	(144,005)	$78.13	CME and IPE Crude(b) (c)
	Position	Bbls per Day	Weighted Average Price	Benchmark
Refined Products				
Exchange-traded	Long(d)	12,373	$2.10	CME Heating Oil and RBOB(b) (e)
Exchange-traded	Short(d)	(7,323)	$2.12	CME Heating Oil and RBOB(b) (e)

(a) 92 percent of these contracts expire in the third quarter of 2010.
(b) Chicago Mercantile Exchange (“CME”).
(c) International Petroleum Exchange (“IPE”).
(d) 95 percent of these contracts expire in the third quarter of 2010.
(e) Reformulated Gasoline Blendstock for Oxygen Blending (“RBOB”).

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Notes to Consolidated Financial Statements (Unaudited)

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statements of income.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	Income Statement Location	2010	2009	2010	2009
Commodity	Sales and other operating revenues	$81	$(1)	$129	$92
Commodity	Cost of revenues	73	17	44	(42)
Commodity	Other income	1	2	3	3
		$155	$18	$176	$53

13. Debt

At June 30, 2010, 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.

In April 2010, we repurchased $500 million in aggregate principal of our debt under two tender offers for the notes below, at a weighted average price equal to 117 percent of face value.

(In millions)	
9.375% debentures due 2012	$34
9.125% debentures due 2013	60
6.000% Senior notes due 2017	68
5.900% Senior notes due 2018	106
7.500% debentures due 2019	112
9.375% debentures due 2022	33
8.500% debentures due 2023	46
8.125% debentures due 2023	41
Total	$500

As a result of the tender offers, we recorded a loss on extinguishment of debt of $92 million, including the transaction premium costs as well as the expensing of related deferred financing costs on the repurchased debt, in the second quarter of 2010.

In May 2010, United States Steel redeemed $89 million of certain industrial development and environmental improvement bonds for which we were liable.

14. Stock-Based Compensation Plans

The following table presents a summary of stock option award and restricted stock award activity for the six months ended June 30, 2010:

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2009	18,230,074	$35.01	1,441,499	$44.89
Granted (a)	4,757,080	30.00	359,245	30.22
Options Exercised/Stock Vested	(205,384)	21.72	(203,860)	50.96
Canceled	(553,847)	39.77	(103,258)	40.58
Outstanding at June 30, 2010	22,227,923	$33.95	1,493,626	$40.83

(a) The weighted average grant date fair value of stock option awards granted was $9.12 per share.

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Notes to Consolidated Financial Statements (Unaudited)

15. Stockholders' Equity

In conjunction with our acquisition of Western Oil Sands Inc. on October 18, 2007, Canadian residents were able to receive, at their election, cash, Marathon common stock or securities exchangeable into Marathon common stock (the "Exchangeable Shares"). The Exchangeable Shares are shares of an indirect Canadian subsidiary of Marathon and were exchanged into Marathon stock based upon an exchange ratio that began at one-for-one and adjusted quarterly to reflect cash dividends. The Exchangeable Shares were exchangeable at the option of the holder at any time and are automatically redeemable on October 18, 2011. They could also be redeemed prior to their automatic redemption if certain conditions were met. Those conditions were met and we filed notice of the proposed redemption in Canada on March 3, 2010. On April 7, 2010, the remaining exchangeable shares were redeemed and the related preferred shares were eliminated in June 2010.

16. Supplemental Cash Flow Information

	Six Months Ended June 30,	
(In millions)	2010	2009
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$53	$-
Income taxes paid to taxing authorities	845	1,050
Commercial paper and revolving credit arrangements, net:		
Commercial paper - issuances	$-	$897
- repayments	-	(897)
Total	$-	$-

The consolidated statements of cash flows exclude changes to the consolidated balance sheets that did not affect cash. The following is a reconciliation of additions to property, plant and equipment to total capital expenditures.

	Six Months Ended June 30,	
(in millions)	2010	2009
Additions to property, plant and equipment	$2,505	$3,207
Change in capital accruals	(228)	(287)
Discontinued operations	-	66
Capital expenditures	$2,277	$2,986

17. 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.

Contractual commitments – At June 30, 2010, Marathon's contract commitments to acquire property, plant and equipment were $2,610 million.

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

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

- Exploration and Production ("E&P") which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- 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 vacuum gas oil.
- Integrated Gas ("IG") which markets and transports products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol, on a worldwide basis.
- 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.

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 2009 Annual Report on Form 10-K and the update to Item 1A. Risk Factors later in this Form 10-Q.

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

Overview and Outlook

Gulf of Mexico Drilling Moratorium

On April 22, 2010, the Deepwater Horizon, a rig that was engaged in drilling operations in the deepwater Gulf of Mexico, sank after an explosion and fire. The incident resulted in a significant oil spill in the Gulf of Mexico. We have no ownership interest in those operations.

As a result of the incident, the U.S. Department of the Interior issued a drilling moratorium through November 30, 2010 to suspend the drilling of wells using subsea blowout preventers or operations using a floating facility. As a result of the drilling moratorium, we suspended drilling an exploratory well on the Innsbruck prospect, located on Mississippi Canyon Block 993. The future effects of the Deepwater Horizon incident or the drilling moratorium, including any new or additional laws or regulations that may be adopted in response, are not known at this time. Our current investment for unproved property and suspended well costs in the Gulf of Mexico is approximately $780 million.

Exploration and Production (“E&P”)

The budget for our 2010 global exploration program is $1 billion. Our current plan is to drill two wells in the deepwater area of the Gulf of Mexico, as discussed below. To the extent our current plans are impacted by the drilling moratorium or new or additional laws or regulations adopted in response to the Deepwater Horizon incident, we may make adjustments to projected funding levels.

In the Gulf of Mexico, we commenced drilling an exploratory well on the Innsbruck prospect in April 2010. As stated above, we suspended drilling, temporarily abandoning this well, and the rig was released without incurring any stand-by or penalty costs. With the expected delivery of the Noble Jim Day rig in the fourth quarter of 2010, we intend to reestablish our Gulf of Mexico exploration and development programs upon expiration of the drilling moratorium unless new laws or regulations prohibit these activities or make them not viable financially. The revised cost of the Innsbruck well is now estimated at $145 million. We are the operator and hold an 85 percent working interest in the prospect.

In December 2009, we began drilling an exploratory well on the Flying Dutchman prospect, located on Green Canyon Block 511 in the Gulf of Mexico. The Flying Dutchman reached its targeted total depth in early May 2010. The

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well encountered hydrocarbon-bearing sands that require further technical evaluation. During the second quarter of 2010, we expensed approximately $51 million for drilling costs incurred below the depth of the hydrocarbon-bearing sands and have approximately $95 million of exploratory well costs suspended as of June 30, 2010. The results of the Flying Dutchman well will be evaluated along with additional potential drilling on Green Canyon Block 511 to determine overall commerciality, which could be impacted by any new or additional laws or regulations that may be adopted in response to the Gulf of Mexico incident described above. We are the operator and have a 63 percent working interest in this prospect.

In Indonesia, the rig has arrived and we will begin drilling a deepwater well in the Pasangkayu block in the third quarter of 2010. We are the operator and hold a 70 percent working interest in the Pasangkayu block.

During the second quarter 2010, we were awarded all five blocks bid in the Central Gulf of Mexico Lease Sale No. 213 conducted by the U.S. Department of the Interior, for a total of $24 million. Four blocks are 100 percent Marathon, and the remaining block was bid with partners.

We continue to acquire additional onshore exploration licenses with shale gas potential in Poland, adding six through July 2010, bringing our total number of licenses to ten and increasing our total acreage position to approximately 2.1 million net acres. We have a 100 percent interest and operate all ten blocks. We continue to pursue additional licenses and plan to begin geologic studies in Poland in 2010 followed by the acquisition of 2D seismic in 2011.

Production

Net liquid hydrocarbon and natural gas sales averaged 386 thousand barrels of oil equivalent per day (“mboepd”) during the second quarter and 374 mboepd during the first six months of 2010 compared to 428 and 411 mboepd during the second quarter and first six months of 2009. This decrease in sales volumes from the prior year was primarily the result of a planned turnaround in Equatorial Guinea, the sale of a portion of our Permian Basin assets in the second quarter of 2009 and normal production declines.

Our Droshky development in the Gulf of Mexico on Green Canyon Block 244 began production in mid-July, on time and under budget. This major subsea project, which consists of four development wells tied back to a third-party platform, is expected to produce approximately 50,000 boepd, net of royalties, at its peak, consisting of approximately 45,000 bpd of liquid hydrocarbons and 30 million cubic feet per day (“mmcfd”) of natural gas. We hold a 100 percent operated working interest and an 81 percent net revenue interest in Droshky.

Our net liquid hydrocarbon sales in North Dakota from the Bakken Shale resource play have increased to 11 thousand barrels per day (“bpd”) in second quarter of 2010 compared to 8 mbpd in the same quarter of last year. We added a fifth operated rig during the second quarter, with plans to add a sixth by the end of 2010.

In the second quarter of 2010, we commenced production at the Volund field offshore Norway which allows us to maintain full capacity on the Alvheim FPSO. We hold a 65 percent operated interest in the Volund field.

Also offshore Norway in the first quarter of 2010, 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.

Divestitures

During the first quarter 2010, we closed the sale of a 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale in the amount of $811 million. We retained a 10 percent outside-operated interest in Block 32.

The above discussions include forward-looking statements with respect to the timing and levels of future production, exploration budget, anticipated future drilling activity and the drilling moratorium. While the drilling moratorium is scheduled to end on November 30, 2010, we cannot predict when it will end. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for crude oil, natural gas and 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 factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements. The exploration budget is based on current expectations, estimates and projections and is not a guarantee of future performance. 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.

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Oil Sands Mining ("OSM")

Our net synthetic crude oil sales were 20 thousand barrels per day ("mbpd") in the second quarter and 22 mbpd in the first six months of 2010 compared to 30 mbpd and 31 mbpd in the periods of 2009, reflecting the impact of a planned turnaround at the mine and upgrader that began March 22, 2010 and halted production in April before a staged resumption of operations in May. Our net share of total turnaround costs in the first six months of 2010 was $99 million.

The AOSP Expansion 1 is anticipated to begin a phased start-up of mining operations in the third quarter of 2010, and upgrader operations in late 2010 or early 2011. Expansion 1 includes construction of mining and extraction facilities at the Jackpine mine, expansion of treatment facilities at the existing Muskeg River mine, expansion of the Scotford upgrader and development of related infrastructure. We hold a 20 percent working interest in the AOSP.

The above discussion includes forward-looking statements with respect to the start of operations of AOSP Expansion 1. 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.

Integrated Gas ("IG")

Our share of LNG sales worldwide totaled 6,556 metric tonnes per day ("mtpd") for the second quarter of 2010 compared to 6,611 mtpd in the second quarter of 2009 and 6,176 mtpd in the first six months of 2010 compared to 6,690 mtpd in the first six months of 2009. 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.

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

Our total refinery throughputs were 20 percent higher in the second quarter and 12 percent higher in the first six months of 2010 compared to the same periods of 2009. Crude oil refined likewise increased 28 percent and 23 percent the same periods primarily related to the startup of the Garyville, Louisiana expansion, while other charge and blendstocks decreased 18 percent and 38 percent. Due to the significant turnaround activity in the first quarter of 2010 along with the expected reduction in external charge and blendstocks requirements due to the Garyville refinery expansion, we have seen a reduction in our first half 2010 purchased charge and blendstocks volume.

We completed turnarounds at both the Garyville and Texas City, Texas, refineries in the first quarter of 2010 as well as a turnaround at our Catlettsburg, Kentucky refinery in the second quarter of 2010. Such activity in 2010 compares to turnarounds at our Canton, Ohio; Robinson, Illinois; Catlettsburg and Garyville refineries in the first half of 2009.

The refinery units completed as part of the expansion at Garyville have now been fully integrated into the Garyville refinery and are operating as expected. The 180,000 bpd expansion establishes the Garyville facility as the fourth-largest U.S. refinery with a rated crude oil capacity of 436,000 bpd.

Ethanol volumes sold in blended gasoline increased to an average of 67 mbpd for the second quarter and 65 mbpd in the first six months of 2010 compared to 60 mbpd and 58 mbpd in the same periods of 2009. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

Second quarter 2010 Speedway SuperAmerica LLC ("SSA") same store gasoline sales volume increased 5 percent when compared to the second quarter of 2009, while same store merchandise sales increased by 4 percent for the same period. During the first quarter of 2010, Speedway was ranked the nation's top retail gasoline brand for the second consecutive year, according to the 2010 EquiTrend® Brand Study conducted by Harris Interactive®.

As of June 30, 2010, the heavy oil upgrading and expansion project at our Detroit, Michigan, refinery was approximately 41 percent complete and on schedule for an expected completion in the second half of 2012.

In May 2010, we entered into a non-binding letter of intent to sell our RM&T segment's St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 Speedway SuperAmerica retail outlets, plus related inventories. A final agreement is being negotiated and the sale is anticipated to close by year end 2010.

The above discussion includes forward-looking statements with respect to the Detroit refinery project and the sale of the Minnesota assets. Factors that could affect the Detroit refinery project 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. Some factors that could potentially affect the sale of Minnesota assets include completion of due diligence,

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execution of a definitive agreement, buyer financing and customary closing conditions, including government and regulatory approvals. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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 have been volatile in recent years. The following table lists benchmark crude oil and natural gas price averages in the second quarter and first six months of 2010, when compared to the same periods in 2009.

	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2010	2009	2010	2009
West Texas Intermediate ("WTI") crude oil (Dollars per barrel)	$ 78.05	$ 59.79	$ 78.46	$ 51.68
Brent crude oil (Dollars per barrel)	$ 78.24	$ 59.13	$ 77.29	$ 51.68
Henry Hub natural gas (Dollars per mmbtu)(a)	$ 4.09	$ 3.51	$ 4.70	$ 4.21

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

Our domestic crude oil production is about 62 percent sour, which means that it contains more sulfur than light sweet WTI does. Sour crude oil also tends to be heavier than and sells at a discount to light sweet crude oil because of its higher refining costs and lower refined product values. Our international crude oil production is relatively sweet and is generally sold in relation to the Dated Brent crude oil benchmark.

A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas. Our other major natural gas-producing region is Equatorial Guinea, where large portions of our natural gas sales is subject to term contracts, making realized prices in this area 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 prices realizations may decrease.

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. Roughly 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 market, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mine or upgrader. See Note 12 for the commodity derivatives contracts related to 2010 forecasted sales.

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 rate. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian 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 second quarter and first six months of 2010 and 2009:

	Three Months Ended June 30,		Six Months Ended June 30,	
Benchmark	2010	2009	2010	2009
WTI crude oil (Dollars per barrel)	$ 78.05	$ 59.79	$ 78.46	$ 51.68
Western Canadian Select (Dollars per barrel)(a)	$ 63.95	$ 52.19	$ 66.81	$ 43.17
AECO natural gas sales index (Canadian dollars per gigajoule)(b)	3.69	3.28	4.21	3.76

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

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

Integrated Gas

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.

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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. In general, LNG delivered to the U.S. is tied to Henry Hub prices and will track with changes in U.S. natural gas prices, while LNG sold in Europe and Asia is indexed to crude oil prices and will track the movement of those 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"). Methanol demand has a direct impact on AMPCO's earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. AMPCO's plant capacity is 1.1 million tonnes, or 3 percent of estimated 2009 world demand.

Refining, Marketing and Transportation

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

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 market prices for refined products and crude oil, commonly used by the industry as a proxy for 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.

Our refineries can process significant amounts of sour crude oil which typically can be purchased at a discount to sweet crude oil. The amount of this discount, the sweet/sour differential, can vary significantly causing our refining and wholesale marketing gross margin to differ from the crack spreads which are based upon sweet crude. In general, a larger sweet/sour differential will enhance our refining and wholesale marketing gross margin.

In addition to the market changes indicated by the crack spreads and sweet/sour differential, 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, energy used by our refineries and the level of maintenance costs.

The following table lists calculated average crack spreads for the Midwest and Gulf Coast markets and the sweet/sour differential for the second quarter and first six months of 2010 and 2009:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Dollars per barrel)	2010	2009	2010	2009
Chicago LLS 6-3-2-1 crack spread	$ 3.86	$ 5.73	$ 3.28	$ 4.34
U.S. Gulf Coast LLS 6-3-2-1 crack spread	$ 2.33	$ 3.59	$ 2.90	$ 3.25
Sweet/Sour differential(a)	$ 8.78	$ 3.98	$ 7.03	$ 5.60

(a) Calculated using the following mix of crude types: 15% Arab Light, 20% Kuwait, 10% Maya, 15% Western Canadian Select and 40% Mars compared to WTI.

Even though the LLS 6-3-2-1 crack spread was lower in second quarter and first six months of 2010 compared to the same periods of 2009, we realized improved financial earnings from processing sour crude, due to the widening of the sweet/sour differential. The benchmark sweet/sour differential widened 120 percent in the second quarter and 25 percent in the first six months of 2010 relative to the same periods of last year. Due to the Garyville refinery expansion we were also able to process a higher volume of sour crude oil during the second quarter 2010. Within our refining system, sour crude accounted for 56 percent of the 1,229 mbpd of crude oil processed in the second quarter of 2010 and 55 percent of the 1,117 mbpd of crude oil processed in the first six months of 2010 compared to 54 percent of the 959 mbpd of crude processed in the second quarter and 53 percent of the 905 mbpd of crude processed in the first six months in 2009.

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Our retail marketing gross margin for gasoline and distillates, which is the difference between the ultimate price paid by consumers and the cost of refined products, including secondary transportation and consumer excise taxes, also impacts RM&T segment profitability. There are numerous factors including local competition, seasonal demand fluctuations, the available wholesale supply, the level of economic activity in our marketing areas and weather conditions that impact gasoline and distillate demand throughout the year. The gross margin on merchandise sold at retail outlets has been historically less volatile.

Results of Operations

Consolidated Results of Operation

Consolidated net income for 2010 was 72 percent higher in second quarter and 68 percent higher in the first six months than in the same periods of 2009. Our E&P and RM&T segments' income increases in the second quarter were driven primarily by higher liquid hydrocarbon prices, refining and marketing gross margins and throughput.

Revenues are summarized by segment in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
E&P	$ 2,630	$ 1,967	$ 5,151	$ 3,407
OSM	179	155	344	277
IG	33	7	60	18
RM&T	15,795	11,067	29,157	19,741
Segment revenues	18,637	13,196	34,712	23,443
Elimination of intersegment revenues	(188)	(160)	(394)	(313)
Gain on U.K. natural gas contracts	-	3	-	85
Total revenues	$ 18,449	$ 13,039	$ 34,318	$ 23,215
Items included in both revenues and costs:				
Consumer excise taxes on petroleum products and merchandise	$ 1,308	$ 1,226	$ 2,520	$ 2,400

E&P segment revenues increased $663 million in the second quarter and $1,744 million in the first six months of 2010 from the comparable prior-year periods. The increases were primarily a result of higher liquid hydrocarbon and natural gas price realizations. Liquid hydrocarbon realizations averaged $73.68 per barrel in the second quarter and $74.00 in the first six months of 2010 compared to $55.88 and $48.80 in the same periods of 2009, while natural gas realizations averaged $2.61 per mcf in the second quarter and $2.95 in the first six months of 2010 compared to $2.19

and $2.51 in the same periods of 2009.

Revenues in both 2010 periods include the impact of derivative instruments intended to mitigate price risk on future sales of liquid hydrocarbons and natural gas. A net pretax gain of $29 million was reported by the E&P segment in the second quarter of 2010, while there was a net pretax gain of $78 million in the first six months of 2010.

Net sales volumes during the quarter were 386 mboepd in 2010 and 428 mboepd in 2009. Net sales volumes for the first six months of 2010 were 9 percent lower than the comparable prior-year period, primarily impacted by the sale of a portion of our Permian Basin assets in the second quarter of 2009, the planned turnaround in Equatorial Guinea, and normal production declines. This decrease in sales volumes partially offsets the impact of liquid hydrocarbon and natural gas realization increases previously discussed.

For the second quarter and the first six months of 2009, gains of $3 million and $85 million related to natural gas sales contracts in the U.K. that are accounted for as derivative instruments were excluded for E&P segment revenues. Those contracts expired in the third quarter of 2009.

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The following tables report E&P segment realizations and sales volumes in greater detail for all periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd)				
United States	57	64	57	65
Europe	110	112	98	92
Africa	79	92	81	89
Total International	189	204	179	181
Worldwide Continuing Operations	246	268	236	246
Discontinued Operations(a)	-	9	-	4
Worldwide	246	277	236	250
Natural Gas Sales (mmcfd)				
United States	334	365	343	395
Europe(b)	104	151	106	155
Africa	402	439	378	436
Total International	506	590	484	591
Worldwide Continuing Operations	840	955	827	986
Discontinued Operations(a)	-	3	-	33
Worldwide	840	958	827	1,019
Total Worldwide Sales (mboepd)				
Continuing Operations	386	428	374	411
Discontinued Operations(a)	-	9	-	10
Worldwide	386	437	374	421

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
E&P Operating Statistics				
Average Realizations (c)				
Liquid Hydrocarbons (per bbl)				
United States	$68.01	$53.25	$70.25	$44.84
Europe	79.66	60.91	79.36	55.71
Africa	69.41	51.62	70.20	44.52
Total International	75.37	56.70	75.20	50.22
Worldwide Continuing Operations	73.68	55.88	74.00	48.80
Discontinued Operations	-	43.01	-	43.05
Worldwide	$73.68	$55.49	$74.00	$48.70

Natural Gas (per mcf)				
United States	$4.41	$3.60	$4.96	$4.08
Europe	5.92	4.43	6.05	4.90
Africa	0.25	0.25	0.25	0.25
Total International	1.41	1.32	1.52	1.47
Worldwide Continuing Operations	2.61	2.19	2.95	2.51
Discontinued Operations	-	7.49	-	8.54
Worldwide	$2.61	$2.21	$2.95	$2.71

(a) Our businesses in Ireland and Gabon were sold in 2009. The 2009 values have been recast to reflect these businesses as discontinued operations.

(b) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 18 mmcfd for the second quarters of 2010 and 2009, and 21 mmcfd and 21 mmcfd for the first six months of 2010 and 2009.

(c) Excludes gains and losses on derivative instruments and the unrealized effects of U.K. natural gas contracts that were accounted for as derivatives in 2009.

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OSM segment revenues increased $24 million in the second quarter and $67 million in the first six months of 2010 compared to the same periods of 2009. Revenues in both periods include the impact of derivative instruments intended to mitigate price risk relative to future sales of synthetic crude. Derivative gains of $53 million and $43 million were included in segment revenues for the second quarter and first six months of 2010, but were not significant in 2009.

Excluding the derivative gains, segment revenues decreased in both periods of 2010, primarily due to lower sales volumes as both periods were impacted by a turnaround that commenced on March 22, 2010 that caused production to be completely shutdown in April with a staged resumption of operations in May. Net synthetic crude sales for the second quarter of 2010 were 20 mbpd at an average realized price of $65.11 per barrel compared to 30 mbpd at $55.02 in the same period last year. For the six months period net synthetic crude sale of 22 mbpd at $69.94 in 2010 compared to 31 mbpd at $46.63 in 2009.

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

RM&T segment revenues increased $4,728 million in the second quarter of 2010 and $9,416 million in the first six months of 2010 from the comparable periods of 2009. Our refined product and liquid hydrocarbon selling prices were higher as illustrated by the spot benchmark prices in the following table and accounted for 61 percent of the quarterly and 76 percent of year-to-date overall revenue increase. Refined product sales volumes increased 17 percent in the second quarter and 12 percent in the first six months of 2010, in part due to higher production from our expanded Garyville refinery.

	Three Months Ended June 30,		Six Months Ended June 30,	
(Dollars per gallon)	2010	2009	2010	2009
Chicago Spot Unleaded regular gasoline	$ 2.11	$ 1.74	$ 2.07	$ 1.49
Chicago Spot Ultra-low sulfur diesel	2.16	1.57	2.10	1.44
USGC Spot Unleaded regular gasoline	2.05	1.64	2.05	1.43
USGC Spot Ultra-low sulfur diesel	$ 2.14	$ 1.57	$ 2.10	$ 1.45

Income from equity method investments increased $39 million in the second quarter of 2010 and $97 million in the first six months of 2010 from the comparable prior-year periods. Higher commodity prices in 2010 compared to 2009 positively impacted the earnings of many of our equity method investees.

Net gain on disposal of assets in the first six months of 2010 primarily represents the sale of a 20 percent outside-operated undivided interest in our Production Sharing and Joint Operating Agreement in Block 32 offshore Angola. During the first quarter of 2010, we recorded a gain of $811 million on the sale. The net gain on disposal of assets in the first six 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 increased $4,532 million and $10,056 million in the second quarter and first six months of 2010 from the comparable periods of 2009. In both periods, the increase was primarily the result of higher acquisition costs of crude oil, charge and blendstocks and purchased refined products in the RM&T segment. Increased volumes of purchased crude oil also contributed to the increased costs.

Depreciation, depletion and amortization (“DD&A”) decreased in second quarter and first six months of 2010 from the comparable prior-year periods. Decreased DD&A related to the lower sales volumes in our E&P and OSM segments and a lower rate of DD&A per barrel on our domestic E&P assets. We had a high DD&A rate in the second quarter of 2009, but reserves were added in the fourth quarter of 2009; thereby reducing the current DD&A per barrel. Increased DD&A related to the Garyville expansion being put in to service at the end of 2009 mostly offset the impact of these decreases. In addition, DD&A in the RM&T segment increased for the second quarter as a result of a $23 million charge to abandon partially completed MSAT II compliance equipment in favor of a more cost effective compliance approach.

Long-lived asset impairments in the second quarter of 2010 related primarily to our maleic anhydride plant. In the first quarter of 2010 the impairments were primarily related to our Powder River Basin field. See Note 11 for information about these impairments.

Exploration expenses were $125 million and $223 million in the second quarter and first six months of 2010, including expenses related to dry wells of $57 million and $89 million. Exploration expenses were $64 million and $126 million in the second quarter and first six months of 2009, including expenses related to dry wells of $8 million and $13 million. The majority of dry well costs in 2010 relate to the partial writeoff of the previously discussed offshore Gulf of Mexico well on the Flying Dutchman prospect.

Provision for income taxes increased $50 million and $306 million in the second quarter and first six months of 2010 from the comparable periods of 2009 primarily due to the increase in pretax income. The effective income tax rate decreased primarily as a result of favorable foreign currency remeasurement effects. Such decrease was partially offset by an increase from legislation changes, see Note 8. The effective tax rate is also influenced by a variety of factors

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including the geographical and functional sources of income and the relative magnitude of these sources of income.

The following is an analysis of the effective income tax rates for the first six months of 2010 and 2009:

	Six Months Ended June 30,	
	2010	2009
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	16	26
State and local income taxes, net of federal income tax effects	-	1
Legislation change	2	-
Other	(1)	-
Effective income tax rate	52 %	62 %

The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in corporate and other unallocated items.

Discontinued operations reflect the 2009 disposal of our E&P businesses in Ireland and Gabon (see Note 5) and the historical results of those operations, net of tax, for all periods presented.

Segment Results

Segment income (loss) is summarized in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
E&P				
United States	$25	$(41)	$134	$(93)
International	407	249	800	384
E&P segment	432	208	934	291
OSM	(60)	2	(77)	(22)
IG	24	13	68	40
RM&T	421	165	184	324
Segment income	817	388	1,109	633
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(62)	(90)	(72)	(140)
Foreign currency remeasurement of income taxes	37	(94)	70	(66)
Gain on dispositions	-	122	449	122
Impairments	(26)	-	(288)	-
Loss on early extinguishment of debt	(57)	-	(57)	-
Deferred income taxes - tax legislation changes	-	-	(45)	-
Gain on U.K. natural gas contracts	-	2	-	44

Discontinued operations	-	85	-	102
Net income	$709	$413	$1,166	$695

United States E&P income increased $66 million and $227 million in the second quarter and first six months of 2010 compared to the same periods of 2009. The income increase was primarily driven by realization increases in both periods as previously discussed. DD&A reductions as result of the lower volumes and DD&A rates were partially offset by increased exploration expenses.

International E&P income increased $158 million and $416 million in the second quarter and first six months of 2010 compared to the same periods of 2009. The income increase is primarily due to revenue increases as previously discussed. Liquid hydrocarbon realizations were up 33 percent and 50 percent for the second quarter and first six months of 2010 compared to the same periods of 2009.

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OSM segment income decreased $62 million and $55 million in the second quarter and first six months of 2010. After-tax derivative gains of $40 million and $32 million were included in income for the second quarter and first six months of 2009. Derivative gains or losses in 2009 were not significant. Exclusive of the derivative effects, the decline in OSM segment income reflects lower volumes sold and higher incremental costs, both primarily related to the previously discussed turnaround. Improved realizations of 18 percent and 50 percent in the second quarter and first six months partially offset the impact of the turnaround on segment income.

IG segment income increased $11 million in the second quarter of 2010 and $28 million in the first six months of 2010 compared to the same periods of 2009. The increase was primarily the result of higher price realizations in both periods of 2010 compared to 2009.

RM&T segment income increased by $256 million in the second quarter but decreased $140 million in first six months of 2010 compared to the same periods of 2009. The increase for the quarter was primarily due to a higher refining and wholesale marketing gross margin, which averaged 13.37 cents per gallon in the second quarter of 2010 compared to 8.71 cents per gallon in the same quarter of 2009. A wider sweet/sour crude differential coupled with an increase in sour crude throughput contributed to the increase in segment income. These favorable impacts were partially offset by increased manufacturing expenses in the second quarter 2010 compared to the second quarter 2009 due to a combination of increased depreciation and energy expense associated with the additional Garyville refinery units.

The decrease in segment income in the six month period was primarily due to a lower refining and wholesale marketing gross margin, which averaged 4.71 cents per gallon in the first six months of 2010 compared to 8.33 cents per gallon in the comparable period of 2009. Impacting the gross margin were higher manufacturing costs relating to a pretax increase of approximately $150 million in refining system turnaround costs and higher depreciation expense related to the Garyville expansion units.

Our refining and wholesale marketing gross margin also included pretax derivative gains of $ 74 million and $51 million in the second quarter and first six months of 2010 compared to gains of $13 million and losses of $47 million in the second quarter and first six months of 2009.

Management's Discussion and Analysis of Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities totaled $2,127 million in the first six months of 2010, compared to $2,037 million in the first six months of 2009.

Net cash used in investing activities totaled $1,142 million in the first six months of 2010, compared to $2,906 million in the first six months of 2009. In the first quarter of 2010, we closed the sale of our 20 percent outside-operated undivided interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. The related cash inflow was $1.3 billion.

In our E&P segment, exploration and development projects in 2010 are offshore in the Gulf of Mexico, on our Angola development and U.S. unconventional resource plays. The 2010 exploration and development budget of $1,023 million is 30 percent higher than 2009 spending. With the completion of our Garyville refinery expansion at the end of 2009, we have reduced spending in our RM&T segment while keeping the expansion and upgrading of our Detroit, Michigan, refinery on track. The AOSP Expansion 1 in our OSM segment continues into 2010, with the spending rate relatively unchanged from 2009 levels.

For further information regarding capital expenditures by segment, see Supplemental Statistics.

Net cash used in financing activities was $970 million in the first six months of 2010, compared to net cash provided of $1,099 million in the first six months of 2009. Sources of cash in the first six months of 2009 included the issuance of $1.5 billion in senior notes, with the only significant use of cash being dividends. Significant uses of cash in the first six months of 2010 included the repayment of $500 million aggregate principal value of debt at a weighted average price of 117 percent of face value under two tender offers in the second quarter of 2010 and dividends.

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.

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Capital Resources

At June 30, 2010, 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 July 16, 2010, 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 various types of debt and equity securities.

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 20 percent at June 30, 2010, compared to 23 percent at December 31, 2009. This includes $239 million of debt that is serviced by United States Steel.

(In millions)	June 30, 2010	December 31, 2009
Long-term debt due within one year	$101	$96
Long-term debt	7,829	8,436
Total debt	$7,930	$8,532
Cash	$2,062	$2,057
Trusteed funds from revenue bonds	$-	$16
Equity	$22,841	$21,910
Calculation:		
Total debt	$7,930	$8,532
Minus cash	2,062	2,057
Minus trusteed funds from revenue bonds	-	16
Total debt minus cash	$5,868	$6,459
Total debt	7,930	8,532
Plus equity	22,841	21,910
Minus cash	2,062	2,057
Minus trusteed funds from revenue bonds	-	16
Total debt plus equity minus cash	$28,709	$28,369
Cash-adjusted debt-to-capital ratio	20 %	23 %

Capital Requirements

On July 28, 2010, our Board of Directors approved a 25 cents per share dividend, payable September 10, 2010 to stockholders of record at the close of business on August 18, 2010. In April 2010, the dividend was increased from 24 cents per share to 25 cents per share, a 4 percent increase in our quarterly dividend.

We expect to make contributions of approximately $230 million to our funded pension plans in the last half of 2010.

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of March 31, 2010, we had repurchased 66 million common shares at a cost of $2,922 million. We have not made any purchases under the program since August 2008. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program's authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

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

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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

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of June 30, 2010:

(In millions)	Total	2010	2011-2012	2013-2014	Later Years
Long-term debt (excludes interest)(a)	$7,571	$34	$1,551	$984	$5,002
Sale-leaseback financing(a)	23	1	22	-	-
Capital lease obligations(a)	628	17	81	88	442
Operating lease obligations(a)	820	72	250	185	313
Operating lease obligations under sublease(a)	15	3	12	-	-
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts	11,522	9,882	1,053	428	159
Transportation and related contracts	1,930	536	300	156	938
Contracts to acquire property, plant and equipment	2,610	1,095	1,514	1	-
LNG terminal operating costs(b)	136	6	25	25	80
Service and materials contracts(c)	2,000	243	510	328	919
Unconditional purchase obligations(d)	47	8	16	16	7
Commitments for oil and gas exploration (non-capital)(e)	28	20	1	1	6
Total purchase obligations	18,273	11,790	3,419	955	2,109
Other long-term liabilities reported in the consolidated balance sheet(f)	2,301	80	643	560	1,018
Total contractual cash obligations(g)	$29,631	$11,997	$5,978	$2,772	$8,884

(a) Includes debt and lease obligations assumed by United States Steel upon the USX Separation.

(b) We have acquired the right to deliver 58 bcf of natural gas per year to the Elba Island LNG re-gasification terminal. The agreement's primary term ends in 2021. Pursuant to this agreement, we are also committed to pay for a portion of the operating costs of the terminal.

(c) Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

(d)

We are a part to a long-term transportation services agreement with Alliance Pipeline. This agreement was used by Alliance Pipeline to secure its financing.

(e) Commitments on oil and gas exploration (non-capital) include estimated costs related to contractually obligated exploratory work programs that are expensed immediately, such as geological and geophysical costs.

(f) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance, which we have estimated through 2019. Also includes amounts for uncertain tax positions.

(g) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties.

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Receivable from United States Steel

We remain obligated (primarily or contingently) for $257 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 2009 Annual Report on 10-K). United States Steel reported in its Form 10-Q for the three months ended June 30, 2010 that it believes that its liquidity will be adequate to satisfy its obligations for the foreseeable future.

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, 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, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil, refined products and feedstocks.

We have finalized our strategic approach to comply with Mobile Source Air Toxics II ("MSAT II") regulations relating to benzene content in refined products and updated the project cost estimates to comply with these requirements. We now estimate that we may spend approximately $675 million over a four-year period that began in 2008, reduced from our previous projection of approximately $1 billion over a six-year period. The overall cost reduction for MSAT II compliance is a result of lower costs for several projects along with our finalization of the most appropriate MSAT II compliance approach for our refineries. Our actual MSAT II expenditures since inception have totaled $401 million through June 30, 2010, with $58 million in the second quarter of 2010. We expect total year 2010 spending will be approximately $300 million. The cost estimates are forward-looking statements and are subject to change as further work is completed in 2010.

There have been no other significant changes to our environmental matters subsequent to December 31, 2009.

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.

There have been no other changes to our critical accounting estimates subsequent to December 31, 2009.

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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 2009 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.

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices on our open commodity derivative instruments as of June 30, 2010 is provided in the following table.

	Incremental Change in IFO from a Hypothetical Price Increase of		Incremental Change in IFO from a Hypothetical Price Decrease of	
(In millions)	10%	25%	10%	25%
E&P Segment				
Natural gas	$(8)	$(20)	$8	$20
OSM Segment				
Crude oil	$(35)	$(88)	$35	$88
RM&T Segment				
Crude oil	$(65)	$(166)	$77	$194
Natural gas	1	2	(1)	(2)
Refined products	16	41	(16)	(41)

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 June 30, 2010, 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.

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MARATHON OIL CORPORATION

Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2010	2009	2010	2009
Segment Income (Loss)				
Exploration and Production				
United States	$25	$(41)	$134	$(93)
International	407	249	800	384
E&P segment	432	208	934	291
Oil Sands Mining	(60)	2	(77)	(22)
Integrated Gas	24	13	68	40
Refining, Marketing and Transportation	421	165	184	324
Segment income	817	388	1,109	633
Items not allocated to segments, net of income taxes	(108)	25	57	62
Net income	$709	$413	$1,166	$695
Capital Expenditures(a)				
Exploration and Production				
United States	$412	$385	$870	$615
International	173	224	318	359
E&P segment	585	609	1,188	974
Oil Sands Mining	243	281	508	567
Integrated Gas	-	1	1	1
Refining, Marketing and Transportation	256	713	566	1,373
Discontinued Operations(b)	-	39	-	63
Corporate	14	7	14	8
Total	$1,098	$1,650	$2,277	$2,986
Exploration Expenses				
United States	$112	$31	$158	$65
International	13	33	65	61
Total	$125	$64	$223	$126

(a) Capital expenditures include changes in accruals.

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

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MARATHON OIL CORPORATION

Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd)				
United States	57	64	57	65
Europe	110	112	98	92
Africa	79	92	81	89
Total International	189	204	179	181
Worldwide Continuing Operations	246	268	236	246
Discontinued Operations	-	9	-	4
Worldwide	246	277	236	250
Net Natural Gas Sales (mmcfd)				
United States	334	365	343	395
Europe(c)	104	151	106	155
Africa	402	439	378	436
Total International	506	590	484	591
Worldwide Continuing Operations	840	955	827	986
Discontinued Operations	-	3	-	33
Worldwide	840	958	827	1,019
Total Worldwide Sales (mboepd)				
Continuing operations	386	428	374	411
Discontinued operations	-	9	-	10
Worldwide	386	437	374	421
Average Realizations (d)				
Liquid Hydrocarbons (per bbl)				
United States	$68.01	$53.25	$70.25	$44.84
Europe	79.66	60.91	79.36	55.71
Africa	69.41	51.62	70.20	44.52
Total International	75.37	56.70	75.20	50.22
Worldwide Continuing Operations	73.68	55.88	74.00	48.80
Discontinued Operations	-	43.01	-	43.05
Worldwide	$73.68	$55.49	$74.00	$48.70
Natural Gas (per mcf)				
United States	$4.41	$3.60	$4.96	$4.08

Europe	5.92	4.43	6.05	4.90
Africa(e)	0.25	0.25	0.25	0.25
Total International	1.41	1.32	1.52	1.47
Worldwide Continuing Operations	2.61	2.19	2.95	2.51
Discontinued Operations	-	7.49	-	8.54
Worldwide	$2.61	$2.21	$2.95	$2.71

(c) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 18 mmcfd in the second quarters of 2010 and 2009, and 21 mmcfd for the first six months of 2010 and 2009.

(d) Excludes gains and losses on derivative instruments, including the unrealized effects of U.K. natural gas contracts that are accounted for as derivatives and expired in September 2009.

(e) Primarily represents a fixed price under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company 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.

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MARATHON OIL CORPORATION

Supplemental Statistics (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except as noted)	2010	2009	2010	2009
OSM Operating Statistics				
Net Synthetic Crude Sales (mbpd) (f)	20	30	22	31
Synthetic Crude Average Realization (per bbl)(g)	$ 65.11	$ 55.02	$ 69.94	$ 46.63
IG Operating Statistics				
Net Sales (mtpd) (h)				
LNG	6,556	6,611	6,176	6,690
Methanol	1,135	1,362	1,147	1,258
RM&T Operating Statistics				
Refinery Runs (mbpd)				
Crude oil refined	1,229	959	1,117	905
Other charge and blend stocks	164	199	130	210
Total	1,393	1,158	1,247	1,115
Refined Product Yields (mbpd)				
Gasoline	753	659	665	638
Distillates	428	319	368	314
Propane	26	23	23	22
Feedstocks and special products	96	73	106	62
Heavy fuel oil	30	25	22	24
Asphalt	81	75	79	70
Total	1,414	1,174	1,263	1,130
Refined Products Sales Volumes (mbpd) (i)	1,610	1,371	1,483	1,329
Refining and Wholesale Marketing Gross Margin (per gallon) (j)	$ 0.1337	$ 0.0871	$ 0.0471	$ 0.0833
Speedway SuperAmerica				
Retail outlets	1,596	1,611	-	-
Gasoline and distillate sales (millions of gallons)	848	806	1,631	1,590
Gasoline and distillate gross margin (per gallon)	$ 0.1328	$ 0.1051	$ 0.1264	$ 0.1059
Merchandise sales	$ 832	$ 809	$ 1,563	$ 1,499
Merchandise gross margin	$ 207	$ 192	$ 385	$ 370

(f) Includes blendstocks.

(g) Excludes gains and losses on derivative instruments.

(h) 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.

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

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

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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

The Town of Kouts, Indiana filed a lawsuit against us and other refining companies in the U.S. District Court for the Northern District of Indiana alleging damages for MTBE contamination. With these additional filings, we are a defendant, along with other refining companies, in five cases arising in four states alleging damages for MTBE contamination. We expect additional lawsuits alleging such damages against us in the future, but likewise do not expect them to significantly impact our consolidated results of operations, financial positions, or cash flows.

Environmental Proceedings

During 2001, we entered into a New Source Review consent decree and settlement of alleged Clean Air Act ("CAA") and other violations with the U.S. EPA covering all of our refineries. The settlement committed us to specific control technologies and implementation schedules for environmental expenditures and improvements to our refineries over approximately an eight-year period, which are now substantially complete. As part of this consent decree, we were required to conduct evaluations of refinery benzene waste air pollution programs (benzene waste "NESHAPS"). Pursuant to a modification to our New Source Review consent decree, we have agreed with the U.S. Department of Justice and U.S. EPA to pay a civil penalty of $408,000 and conduct supplemental environmental projects of approximately $1 million, as part of a settlement of an enforcement action for alleged CAA violations relating to benzene waste NESHAPS. A modification to our New Source Review consent decree was finalized June 30, 2010 and the civil penalty amount has been paid.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The discussion of such risks and uncertainties may be found under Item 1A. Risk Factors in our 2009 Annual Report on Form 10-K. The following are updates to our risk factors.

Our offshore operations involve special risks that could negatively impact us.

Offshore exploration and development operations present technological challenges and operating risks because of the marine environment. Activities in deepwater areas may pose incrementally greater risks because of water depths that limit intervention capability and the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities and could materially and adversely affect our business, financial condition, results of operations, cash flow and market value of our securities.

Restrictions on U.S. Gulf of Mexico deepwater operations and similar action by countries where we do business could have a significant impact on our operations.

As a result of the Deepwater Horizon incident, the U.S. Department of the Interior issued a drilling moratorium to suspend outer continental shelf subsea and floating facility operations through November 30, 2010. Due to this drilling moratorium, we suspended drilling activity on one well in the Gulf of Mexico. While this moratorium is scheduled to end on November 30, 2010, we cannot predict when it will end. An extended moratorium on deepwater drilling activities in the Gulf of Mexico or changes in laws or regulations affecting our operations in these areas could have a material adverse effect on our business, financial condition, results of operations, cash flow and market value of our securities. In addition, other countries where we do business may make changes to their laws or regulations governing offshore operations, including deepwater areas, that could have a similar material adverse effect.

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We will continue to incur substantial capital expenditures and operating costs as a result of compliance with, and changes in environmental health, safety and security laws and regulations, and, as a result, our profitability could be materially reduced.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. As an update to legislation and regulatory activity that impacts or could impact our operations:

- EPA issued a finding in 2009 that greenhouse gases contribute to air pollution that endangers public health and welfare. Related to this endangerment finding, in April of 2010, the EPA finalized a greenhouse gas emission standard for mobile sources (cars and light duty vehicles). The endangerment finding along with the mobile source standard and EPA's determination that greenhouse gases are subject to regulation under the Clean Air Act, will lead to widespread regulation of stationary sources of greenhouse gas emissions. As a result, the EPA has issued a so-called tailoring rule to limit the applicability of the EPA's major permitting programs to larger sources of greenhouse gas emissions, such as our refineries and a few large production facilities. Although legal challenges have been filed or are expected to be filed against these EPA actions, no court decisions are expected for about two years.

- Congress may continue to consider legislation in 2010 on greenhouse gas emissions, which may include a cap and trade system for stationary sources and a carbon fee on transportation fuels.

Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for crude oil or certain refined products) associated with any legislation, regulation or other action, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding the additional measures and how they will be implemented.

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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)
04/01/10 – 04/30/10	3,279	$32.06		$2,080,366,711
05/01/10 – 05/31/10	22,032	$32.37		$2,080,366,711
06/01/10– 06/30/10	63,558 (c)	$31.56		$2,080,366,711
Total	88,869	$31.78	-	

(a) 41,404 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 LLC 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 second quarter of 2010, we acquired 2 shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 47,463 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 June 30, 2010, 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.

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Item 6. Exhibits

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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
3.1	Certificate of Elimination of Special Voting Stock of Marathon Oil Corporation	8-K	3.1	6/30/10			
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	

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SIGNATURES

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

August 6, 2010

MARATHON OIL CORPORATION

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