MARATHON OIL CORP
Form 10-Q
May 10, 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 March 31, 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

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

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

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

There were 709,502,223 shares of Marathon Oil Corporation common stock outstanding as of April 30, 2010.

MARATHON OIL CORPORATION

Form 10-Q

Quarter Ended March 31, 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).

Part I - Financial Information

Item 1. Financial Statements

MARATHON OIL CORPORATION

Consolidated Statements of Income (Unaudited)

	Three Months Ended March 31,	
(In millions, except per share data)	2010	2009
Revenues and other income:		
Sales and other operating revenues (including consumer excise taxes)	$15,849	$10,156
Sales to related parties	20	20
Income from equity method investments	105	47
Net gain on disposal of assets	813	4
Other income	33	52
Total revenues and other income	16,820	10,279
Costs and expenses:		
Cost of revenues (excludes items below)	12,881	7,357
Purchases from related parties	133	95
Consumer excise taxes	1,212	1,174
Depreciation, depletion and amortization	649	660
Long-lived asset impairments	434	-
Selling, general and administrative expenses	298	291
Other taxes	115	102
Exploration expenses	98	62
Total costs and expenses	15,820	9,741
Income from operations	1,000	538
Net interest and other financing costs	(30)	(16)
Income from continuing operations before income taxes	970	522
Provision for income taxes	513	257
Income from continuing operations	457	265
Discontinued operations	-	17
Net income	$457	$282
Per Share Data		

Basic:		
Income from continuing operations	$0.64	$0.37
Discontinued operations	$-	$0.03
Net income	$0.64	$0.40
Diluted:		
Income from continuing operations	$0.64	$0.37
Discontinued operations	$-	$0.03
Net income	$0.64	$0.40
Dividends paid	$0.24	$0.24

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)	March 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$2,718	$2,057
Receivables, less allowance for doubtful accounts of $14 and $14	4,860	4,677
Receivables from United States Steel	22	22
Receivables from related parties	70	60
Inventories	3,848	3,622
Other current assets	221	199
Total current assets	11,739	10,637
Equity method investments	2,004	1,970
Receivables from United States Steel	320	324
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $18,217 and $17,185	31,674	32,121
Goodwill	1,414	1,422
Other noncurrent assets	574	578
Total assets	$47,725	$47,052
Liabilities		
Current liabilities:		
Accounts payable	$7,143	$6,982
Payables to related parties	59	64
Payroll and benefits payable	360	399
Accrued taxes	679	547
Deferred income taxes	408	403
Other current liabilities	638	566
Long-term debt due within one year	98	96
Total current liabilities	9,385	9,057
Long-term debt	8,440	8,436
Deferred income taxes	4,099	4,104
Defined benefit postretirement plan obligations	2,078	2,056
Asset retirement obligations	1,121	1,099
Payable to United States Steel	5	5
Deferred credits and other liabilities	370	385
Total liabilities	25,498	25,142
Commitments and contingencies		

Stockholders’ Equity		
Preferred stock – 5 million shares issued, 1 million shares outstanding (no par value, 6 million shares authorized)	-	-
Common stock:		
Issued – 769 million and 769 million shares (par value $1 per share, 1.1 billion shares authorized)	769	769
Securities exchangeable into common stock – 5 million shares issued, 1 million shares outstanding (no par value, unlimited shares authorized)	-	-
Held in treasury, at cost – 61 million shares	(2,696)	(2,706)
Additional paid-in capital	6,751	6,738
Retained earnings	18,328	18,043
Accumulated other comprehensive loss	(925)	(934)
Total stockholders' equity	22,227	21,910
Total liabilities and stockholders' equity	$47,725	$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)

	Three Months Ended March 31,	
(In millions)	2010	2009
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$457	$282
Adjustments to reconcile net income to net cash provided by operating activities:		
Discontinued operations	-	(17)
Deferred income taxes	(25)	50
Depreciation, depletion and amortization	649	660
Long-lived asset impairments	434	-
Pension and other postretirement benefits, net	50	38
Exploratory dry well costs and unproved property impairments	52	16
Net gain on disposal of assets	(813)	(4)
Equity method investments, net	(42)	11
Changes in:		
Current receivables	(193)	200
Inventories	(235)	18
Current accounts payable and accrued liabilities	448	(473)
All other operating, net	67	29
Net cash provided by continuing operations	849	810
Net cash provided by discontinued operations	-	29
Net cash provided by operating activities	849	839
Investing activities:		
Additions to property, plant and equipment	(1,348)	(1,586)
Disposal of assets	1,342	20
Trusteed funds - withdrawals	-	13
Investments - loans and advances	(7)	(3)
Investments - repayments of loans and return of capital	14	26
Investing activities of discontinued operations	-	(34)
All other investing, net	(11)	6
Net cash used in investing activities	(10)	(1,558)
Financing activities:		
Borrowings	-	1,491
Debt issuance costs	-	(11)
Debt repayments	(2)	(3)
Dividends paid	(172)	(170)
All other financing, net	2	-
Net cash provided by (used in) financing activities	(172)	1,307
Effect of exchange rate changes on cash:		
Continuing operations	(6)	(2)
Discontinued operations	-	(2)
Total effect of exchange rate changes on cash	(6)	(4)
Net increase in cash and cash equivalents	661	584

Cash and cash equivalents at beginning of period	2,057	1,285
Cash and cash equivalents at end of period	$2,718	$1,869

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

MARATHON OIL CORPORATION

Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended March 31,	
(In millions)	2010	2009
Net income	$457	$282
Other comprehensive income (loss)		
Post-retirement and post-employment plans		
Change in actuarial gain	30	8
Income tax provision on post-retirement and post-employment plans	(24)	(9)
Post-retirement and post-employment plans, net of tax	6	(1)
Derivative hedges		
Net unrecognized gain (loss)	2	(27)
Income tax benefit (provision) on derivatives	1	(3)
Derivative hedges, net of tax	3	(30)
Foreign currency translation and other		
Unrealized gain	-	2
Income tax provision on foreign currency translation and other	-	(1)
Foreign currency translation and other, net of tax	-	1
Other comprehensive income (loss)	9	(30)
Comprehensive income	$466	$252

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 presentation of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including 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.

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 ended March 31, 2010, are not necessarily indicative of the results to be expected for the full year.

Reclassifications – We have revised 2009 amounts of capital expenditures in the consolidated statement of cash flows. The presentation within the consolidated statement of cash flows for additions to property, plant and equipment reflects capital expenditures on a cash basis. The following reflects the reclassifications made:

(in millions)	Three Months Ended March 31, 2009	Six Months Ended June 30, 2009	Nine Months Ended September 30, 2009
Capital expenditures from continuing operations, previously reported	$(1,336)	$(2,939)	$(4,350)
Discontinued operations, previously reported	-	(47)	(66)
Reclassification of capital accruals	(284)	(287)	(402)
Additions to property, plant and equipment, including discontinued operations	$(1,620)	$(3,273)	$(4,818)

The corresponding offsets to the amounts above have been reflected within cash provided by operating activities through change in current accounts payable and accrued liabilities.

(in millions)	Three Months Ended March 31, 2009	Six Months Ended June 30, 2009	Nine Months Ended September 30, 2009
Cash flow from operations, previously reported	$555	$1,750	$2,906
Reclassification of capital accruals	284	287	402

Cash flow from operations	$839	$2,037	$3,308

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

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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 next year. 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; however, there will be an impact on the amount of depreciation, depletion and amortization expense recognized in future periods. 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 March 31, 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 significant variable interest but are not the primary beneficiary because our shipments are only 20 percent of 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 will be required to pay over the contract term, which was $1.0 billion as of March 31, 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, including securities exchangeable into common shares. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	Three Months Ended March 31,			
	2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$457	$457	$265	$265
Discontinued operations	-	-	17	17
Net income	$457	$457	$282	$282
Weighted average common shares outstanding	709	709	709	709
Effect of dilutive securities	-	2	-	3
Weighted average common shares, including dilutive effect	709	711	709	712
Per share:				
Income from continuing operations	$0.64	$0.64	$0.37	$0.37
Discontinued operations	$-	$-	$0.03	$0.03
Net income	$0.64	$0.64	$0.40	$0.40

The per share calculations above exclude 12 million and 9 million stock options and stock appreciation rights for the first three months of 2010 and 2009, that were antidilutive.

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Notes to Consolidated Financial Statements (Unaudited)

5. Dispositions

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.

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 U.S.

Our Irish and Gabonese businesses were sold in 2009 and were accounted for as discontinued operations. Segment information for the first three months of 2009 excludes any amounts for these operations.

	Three Months Ended March 31, 2010				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$2,337	$147	$27	$13,338	$15,849
Intersegment (a)	172	18	-	16	206
Related parties	12	-	-	8	20
Segment revenues	2,521	165	27	13,362	16,075
Elimination of intersegment revenues	(172)	(18)	-	(16)	(206)
Total revenues	$2,349	$147	$27	$13,346	$15,869
Segment income (loss)	$502	$(17)	$44	$(237)	$292

Income from equity method investments	37	-	48	20	105
Depreciation, depletion and amortization (c)	397	23	1	220	641
Income tax provision (benefit)(b)	538	(7)	23	(153)	401
Capital expenditures (c)(d)	603	265	1	310	1,179

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

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

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

(d) Includes accruals.

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Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended March 31, 2009				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$1,306	$97	$11	$8,660	$10,074
Intersegment (a)	119	25	-	9	153
Related parties	15	-	-	5	20
Segment revenues	1,440	122	11	8,674	10,247
Elimination of intersegment revenues	(119)	(25)	-	(9)	(153)
Gain on U.K. natural gas contracts(e)	82	-	-	-	82
Total revenues	$1,403	$97	$11	$8,665	$10,176
Segment income (loss)	$83	$(24)	$27	$159	$245
Income (loss) from equity method investments	11	-	42	(6)	47
Depreciation, depletion and amortization (c)	465	37	1	152	655
Income tax provision (benefit)(b)	178	(8)	13	106	289
Capital expenditures (c)(d)	365	286	-	660	1,311

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

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

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

(d) Includes accruals.

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

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

	Three Months Ended March 31,	
(In millions)	2010	2009
Segment income	$ 292	$ 245
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(10)	(50)
Foreign currency remeasurement of taxes	33	28
Gain on disposition(a)	449	-
Long-lived asset impairment(b)	(262)	-
Deferred income taxes - tax legislation changes(c)	(45)	-
Gain on U.K. natural gas contracts	-	42
Discontinued operations	-	17

Net income	$ 457	$ 282

(a) Additional information on this gain can be found in Note 5.

(b) The impairment is further discussed in Note 11.

(c) 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 March 31,	
(In millions)	2010	2009
Total revenues	$15,869	$10,176
Less: Sales to related parties	20	20
Sales and other operating revenues (including consumer excise taxes)	$15,849	$10,156

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Notes to Consolidated Financial Statements (Unaudited)

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended March 31,			
	Pension Benefits		Other Benefits	
(In millions)	2010	2009	2010	2009
Service cost	$ 29	$ 35	$ 5	$ 5
Interest cost	45	42	10	11
Expected return on plan assets	(40)	(40)	-	-
Amortization:				
– prior service cost (credit)	3	3	(1)	(1)
– actuarial loss	25	6	(1)	-
Net periodic benefit cost	$ 62	$ 46	$ 13	$ 15

During the first three months of 2010, we made contributions of $9 million to our funded international pension plans. We expect to make additional contributions up to an estimated $8 million to our funded international pension plans over the remainder of 2010 and do not anticipate making any contributions to our domestic plans. Current benefit payments related to unfunded pension and other postretirement benefit plans were $8 million and $8 million during the first three months of 2010.

8. Income Taxes

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

	Three Months Ended March 31,	
	2010	2009
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	14	13
State and local income taxes, net of federal income tax effects	(1)	1
Legislation change	5	-
Effective income tax rate for continuing operations	53 %	49 %

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 “Corporate and other unallocated items” shown in Note 6.

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

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Notes to Consolidated Financial Statements (Unaudited)

As of March 31, 2010, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated.

United States (a)	2001 - 2008
Canada(b)	2004 - 2008
Equatorial Guinea	2006 - 2008
Libya	2006 - 2008
Norway	2008
United Kingdom	2007 - 2009

(a) Includes federal and state jurisdictions.

(b) Tax years through 2003 have been audited, but remain subject to reexamination due to the existence of net operating losses.

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)	March 31, 2010	December 31, 2009
Liquid hydrocarbons, natural gas and bitumen	$1,560	$1,393
Refined products and merchandise	1,933	1,790
Supplies and sundry items	355	439
Total, at cost	$3,848	$3,622

10. Property, Plant and Equipment

(In millions)	March 31, 2010	December 31, 2009
Exploration and Production		
United States	$5,839	$6,005

International	4,912	5,522
Total E&P	10,751	11,527
Oil Sands Mining	8,776	8,531
Integrated Gas	35	34
Refining, Marketing & Transportation	11,979	11,887
Corporate	133	142
Total	$31,674	$32,121

Exploratory well costs capitalized greater than one year after completion of drilling were $173 million as of March 31, 2010, an increase of $23 million from December 31, 2009. The offshore Gulf of Mexico Shenandoah appraisal well 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 expected to commence in 2011. 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.

The coal bed methane project in the United Kingdom was added to this category in the first quarter of 2010 at a cost of $15 million. Most of the project costs were incurred in 2008. Technical work is ongoing to develop well design programs along with sourcing a suitable drilling rig.

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Notes to Consolidated Financial Statements (Unaudited)

In December 2009, we began drilling 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 well encountered hydrocarbon-bearing sands in an Upper Miocene that will require further technical evaluation. During the second quarter of 2010, we anticipate expensing approximately $45 million for drilling costs incurred below the depth of the hydrocarbon-bearing sands. The results of the Flying Dutchman well will be evaluated along with additional potential drilling on Green Canyon Block 511 to determine overall commerciality. As a result, approximately $90 million of exploratory well costs will be suspended while we evaluate the results. We are the operator and will have a 63 percent working interest in this prospect.

11. Fair Value Measurements

Fair Values –Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis, as of March 31, 2010 and December 31, 2009 by fair value hierarchy level.

	March 31, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$153	$49	$2	$46	250
Interest rate	-	-	11	-	11
Foreign currency	-	-	5	-	5
Derivative instruments, assets	153	49	18	46	266
Derivative instruments, liabilities					
Commodity	$(146)	$(39)	$(10)	$-	(195)
Derivative instruments, liabilities	(146)	(39)	(10)	-	(195)
Net derivative assets	$7	10	8	46	71

	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)
Net derivative assets	$ 8	$ -	$ 9	$ 63	$ 80

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 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 and interest rate derivatives in Level 3 are measured at fair value with a market approach using prices obtained from various third-party services such as 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, these measures are considered Level 3.

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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 March 31,	
(In millions)	2010	2009
Beginning balance	$9	$(26)
Total realized and unrealized gains (losses):		
Included in net income	(1)	77
Included in other comprehensive income	2	-
Purchases	2	-
Sales	-	(22)
Settlements	(4)	(20)
Ending balance	$8	$9

Net income for the quarters ended March 31, 2010, and 2009 included unrealized losses of $1 million and gains of $76 million related to instruments held on those dates. See Note 12 for the impacts of our derivative instruments on our consolidated statements of income. There were no transfers of fair value estimates among hierarchy levels in the first quarter of 2010.

Fair Values – Nonrecurring

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

	Three Months Ended March 31,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$144	$434	$-	$-

In the first quarter of 2010, we recorded property impairments of $434 million. 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. The field's fair value was measured at $144 million, using an estimate of future cash flows with Level 3 inputs. This resulted in an impairment of $423 million. The remaining E&P segment impairments of $11 million were primarily a result of reduced drilling expectations. The fair value of the assets impaired was measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

Fair Values – Reported

The following table summarizes financial instruments, excluding the derivative financial instruments reported above, by individual balance sheet line item at March 31, 2010, and December 31, 2009.

	March 31, 2010		December 31, 2009	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Receivables from United States Steel, including current portion	$356	$342	$360	$346
Other noncurrent assets	339	181	334	175
Total financial assets	695	523	694	521
Financial liabilities				
Long-term debt, including current portion(a)	8,755	8,188	8,754	8,190
Deferred credits and other liabilities	76	78	71	73
Total financial liabilities	$8,831	$8,266	$8,825	$8,263

(a) Excludes capital leases.

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Notes to Consolidated Financial Statements (Unaudited)

Our current assets and liabilities accounts contain 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 and the current portion of our long-term debt which is reported above. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments (e.g., less than 1 percent of our trade receivables and payables are outstanding for greater than 90 days), (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The fair value of the receivables from United States Steel is measured using an income approach that discounts the future expected payments over the remaining term of the obligations. Because this asset is not publicly-traded and not easily transferable, a hypothetical market based upon United States Steel's borrowing rate curve is assumed and the majority of inputs to the calculation are Level 3. The industrial revenue bonds are to be redeemed on or before January 1, 2012, the tenth anniversary of the USX Separation.

Restricted cash is included in our other noncurrent assets line. The majority of our restricted cash represent cash accounts that earn interest; therefore, the balance approximates fair value. Fair values of our other financial assets included in our other noncurrent assets line and of our financial liabilities included in our deferred credits and other liabilities line are measured using an income approach and mostly are internally generated inputs, 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.

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 March 31, 2010 and December 31, 2009.

	March 31, 2010			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ 5	$ -	$ 5	Other current assets

Fair Value Hedges				
Interest rate	11	-	11	Other noncurrent assets
Total Designated Hedges	16	-	16	
Not Designated as Hedges				
Commodity	202	(162)	40	Other current assets
Total Not Designated as Hedges	202	(162)	40	
Total	$ 218	$ (162)	$ 56	

	March 31, 2010			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 2	$ (33)	$ (31)	Other current liabilities
Total Not Designated as Hedges	2	(33)	(31)	
Total	$ 2	$ (33)	$ (31)	

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Notes to Consolidated Financial Statements (Unaudited)

	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	

	December 31, 2009			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
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 March 31, 2010, the following foreign currency options were designated as cash flow hedges.

(In millions)	Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Options:			
Dollar (Canada)	April 2010 - December 2010	$ 144	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 for the first quarters of 2010 and 2009.

	Gain (Loss) in OCI Three Months Ended March 31,	
(In millions)	2010	2009
Foreign currency	$2	$(12)
Interest rate	$-	$(15)

Derivatives Designated as Fair Value Hedges

As of March 31, 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 4.4 percent. The offsetting impacts on both the derivative and the hedged item were $5 million in the first quarter of 2010.

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Notes to Consolidated Financial Statements (Unaudited)

Derivatives not Designated as Hedges

At March 31, 2010, Euro forwards not designated as hedges with a notional value of $2 million remain open to June 2010 at a weighted average forward rate of 1.290.

The largest portion of our March 31, 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				
U.S.	April - June 2010	35,000	$80.77	West Texas Intermediate
Norway	April - June 2010	30,000	$80.42	Dated Brent
Canada	April - 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	April - December 2010	80,000	$5.39	CIG Rocky Mountains(b)
U.S. Lower 48	April - 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 our significant open commodity derivative contracts of our RM&T segment at March 31, 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)	65,019	$79.07	NYMEX Crude
Exchange-traded	Short(a)	(81,805)	$80.06	NYMEX Crude

	Position	Bbls per Day	Weighted Average Price	Benchmark
Refined Products				
Exchange-traded	Long(b)	21,915	$2.18	NYMEX Heating Oil and RBOB(c)
Exchange-traded	Short(b)	(17,616)	$2.22	NYMEX Heating Oil and RBOB(c)

(a) 90 percent of these contracts expire in the second quarter of 2010.

(b) 98 percent of these contracts expire in the second quarter of 2010.

(c) Reformulated Gasoline Blendstock for Oxygen Blending.

The following table summarizes the effect of all derivative instruments not designated as hedges in our consolidated statements of income for the three months ended March 31, 2010 and 2009.

		Gain (Loss) Three Months Ended March 31,	
(In millions)	Income Statement Location	2010	2009
Commodity	Sales and other operating revenues	$48	$93
Commodity	Cost of revenues	(29)	(59)
Commodity	Other income	2	1
		$21	$35

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Notes to Consolidated Financial Statements (Unaudited)

13. Debt

At March 31, 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, we expect to recognize a second quarter estimated 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.

14. 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 have been 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.

The related Marathon voting preferred shares have also been acquired and are being held in treasury.

15. Commitments and Contingencies

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

Contractual commitments – At March 31, 2010, our contract commitments to acquire property, plant and equipment totaled $2,850 million.

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Notes to Consolidated Financial Statements (Unaudited)

16. Supplemental Cash Flow Information

	Three Months Ended March 31,	
(In millions)	2010	2009
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$ 39	$ -
Income taxes paid to taxing authorities	406	648
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.

	Three Months Ended	
(in millions)	2010	2009
Additions to property, plant and equipment	$ 1,348	$ 1,586
Change in capital accruals	(169)	(284)
Discontinued operations	-	34
Capital expenditures	$ 1,179	$ 1,336

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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 significant 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.

Overview and Outlook

Exploration and Production

Production

Net liquid hydrocarbon and natural gas sales averaged 361 thousand barrels of oil equivalent per day ("mboepd") during the first quarter of 2010 compared to 393 mboped in the same quarter 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 operations in Equatorial Guinea were not producing for a portion of the first quarter due to a planned turnaround at our production facilities.

Our net liquid hydrocarbon sales in North Dakota from the Bakken Shale resource play have increased to 11,000 barrels per day ("bpd") in first quarter 2010 compared to 8,500 bpd in the same quarter of last year. Development of the Bakken Shale play is part of our targeted expansion into key North America resource plays.

In the Gulf of Mexico, the Droshky development located on Green Canyon Block 244, in which we hold a 100 percent working interest, remains on schedule for first production in mid-2010. We have completed all four of its development wells and are awaiting modification of the third-party Bullwinkle platform. The Droshky project is currently expected to cost less than $1 billion, down from the original $1.3 billion budget.

Exploration

The budget for our 2010 global exploration drilling program is $1 billion. We plan to drill three or four significant wells in the deepwater area of the Gulf of Mexico, as well as two potentially high-reward, but high-risk wells in deepwater offshore Indonesia. Additionally, we anticipate drilling or participating in approximately 20 to 30 wells in emerging North America resource plays.

In December 2009, we began drilling 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 well encountered hydrocarbon-bearing sands in an Upper Miocene that will require further technical evaluation. During the second quarter of 2010, we anticipate expensing approximately $45 million for drilling costs incurred below the depth of the hydrocarbon-bearing sands. The results of the Flying Dutchman well will be evaluated along with additional potential drilling on Green Canyon Block 511 to determine overall commerciality. As a result, approximately $90 million of exploratory well costs will be suspended while we evaluate the results. We are the operator and will have a 63 percent working interest in this prospect.

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We commenced drilling the Innsbruck prospect, located on Mississippi Canyon Block 993 in April 2010 and expect it to reach total depth in the third quarter of 2010 for a total cost of about $115 million. We are the operator and hold an 85 percent working interest in the prospect.

In Indonesia, we expect to spud a deepwater well in the Pasangkayu block mid-2010. We are the operator and hold a 70 percent working interest in the Pasangkayu block.

We submitted apparent high bids totaling $24 million on five blocks offered in the Central Gulf of Mexico Lease Sale No. 213 conducted by the Minerals Management Service in the first quarter of 2010. Four blocks are 100 percent Marathon, and the remaining block was bid with partners. The acreage will build on our strong positions in the Miocene and Lower Tertiary deepwater plays.

We were awarded three additional onshore exploration licenses in Poland with shale gas potential during the first quarter of 2010, and another in April, bringing our total number of licenses to seven and increasing our total acreage position to approximately 1.4 million net acres. We have a 100 percent interest and operate all seven blocks. We continue to pursue additional licenses and plan to begin geologic studies in Poland in 2010.

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, anticipated future exploratory drilling activity and exploration spending. The exploration spending budget is based on current expectations, estimates and projections and is not a guarantee of future performance. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

Our net synthetic crude oil sales were 25 thousand barrels per day (“mbpd”) in the first quarter of 2010 compared to 32 mbpd in the same quarter of 2009, reflecting the impact of a planned turnaround at the mine and upgrader that began March 22, 2010 and a buildup of bitumen required for the AOSP Expansion 1. Sales in the second quarter of 2010 will also be impacted by the turnaround, with production anticipated to be completely shutdown in April with a staged startup of operations commencing in May 2010. The turnaround is expected to cost approximately $85 million to

$120 million, net to our ownership. We have incurred $30 million during the first quarter of 2010.

The AOSP Expansion 1 is on track and anticipated to begin mine operations in the second half 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 and the start up of operations coming out of the turnaround. 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

Our share of LNG sales worldwide totaled 5,792 metric tonnes per day (“mtpd”) for the first quarter of 2010 compared to 6,769 mtpd in the first quarter 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 that purchase dry gas from our E&P assets in Equatorial Guinea. Despite a planned turnaround at the Equatorial Guinea gas production facilities, which significantly reduced natural gas volumes to the LNG and methanol facilities during the quarter, we took advantage of higher LNG and methanol prices through the sale of inventories.

Refining, Marketing and Transportation

Our total refinery throughputs were 3 percent higher in the first quarter of 2010 than in the first quarter of 2009. Crude oil refined increased 18 percent for the same periods, primarily related to the startup of the Garyville, Louisiana,

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expansion, while other charge and blendstocks decreased 56 percent. The throughput decline in other charge and blendstocks is primarily a result of the turnarounds we completed at both the Garyville and the Texas City, Texas, refineries in the first quarter of 2010. We also initiated a turnaround at our Catlettsburg, Kentucky refinery in the first quarter of 2010 which was completed in April 2010. Such activity in 2010 compares to turnarounds at our Catlettsburg and Robinson, Illinois, refineries in the first quarter 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 crude oil capacity of 436,000 bpd.

Ethanol volumes sold in blended gasoline increased to an average of 63 mbpd in the first quarter of 2010 compared to 55 mbpd in the same period of 2009. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

First quarter 2010 Speedway SuperAmerica LLC same store gasoline sales volume were about the same when compared to the first quarter of 2009 while same store merchandise sales increased 7 percent for the same period. During the first quarter, 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 March 31, 2010, the heavy oil upgrading and expansion project at our Detroit, Michigan, refinery was approximately 35 percent complete and on schedule for an expected completion in the second half of 2012.

The above discussion includes forward-looking statements with respect to the Detroit refinery project. Factors that could affect this 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. These factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Other

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 and uncontrolled oil spill in the Gulf of Mexico. We have no ownership interest in those operations or any adjacent interests. However, we do have significant exploration and production activities in the Gulf of Mexico, including deepwater areas. Also, we have an interest in an offshore oil port in the Gulf of Mexico and significant portions of the crude oil supplied to our refineries must be transported through the Gulf. At this time, the Deepwater Horizon incident is having no significant effect on our operations in the Gulf of Mexico. However, we cannot predict what, if any, ultimate impact the Deepwater Horizon incident will have on us.

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 the benchmark crude oil and natural gas price averages in the first quarter in 2010, when compared to the same period in 2009.

	Three Months Ended March 31,	
	2010	2009
West Texas Intermediate crude oil (Dollars per barrel)	$78.88	$43.31
Brent crude oil (Dollars per barrel)	$76.36	$44.46
Henry Hub natural gas (Dollars per mmbtu)(a)	$5.30	$4.91

(a) First-of-month price index.

While crude oil prices did not vary significantly within the first three months of 2010, the quarterly average for the first quarter of 2010 was significantly higher compared to the first quarter in 2009.

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.

Natural gas prices for the first quarter of 2010 were slightly higher compared to the same quarter in prior year. 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

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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.

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 first quarter of 2010 compared to first quarter of 2009.

	Three Months Ended March 31,	
Benchmark	2010	2009
WTI crude oil (Dollars per barrel)	$78.88	$43.31
Western Canadian Select (Dollars per barrel)(a)	$69.67	$34.15
AECO natural gas sales index (Canadian dollars per gigajoule)(b)	4.73	4.72

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

(b) Alberta Energy Company 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.

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.

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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 first quarters of 2010 and 2009:

	Three Months Ended March 31,	
(Dollars per barrel)	2010	2009
Chicago LLS 6-3-2-1 crack spread	$2.68	$2.91
U.S. Gulf Coast LLS 6-3-2-1 crack spread	$3.50	$2.89
Sweet/Sour differential(a)	$5.23	$7.28

(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 similar and sour crude accounted for 52 percent of sour crude oil processed in the first quarters of 2010 and 2009, the economic benefit that we recognized from processing sour crude was lower in 2010. The sweet/sour differential narrowed 28 percent in the first quarter of 2010 relative to the same quarter of 2009.

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.

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Results of Operations

Consolidated Results of Operations

Consolidated net income in the first quarter of 2010 was 62 percent higher than in the same quarter of 2009. Increasing liquid hydrocarbon prices contributed to the income increase, as did the gain on our sale of 20 percent of Angola Block 32. However, costs were higher in the first quarter of 2010 due to an E&P segment long-lived asset impairment and turnarounds of varying size in every business segment.

Revenues are summarized by segment in the following table:

	Three Months Ended March 31,	
(In millions)	2010	2009
E&P	$ 2,521	$ 1,440
OSM	165	122
IG	27	11
RM&T	13,362	8,674
Segment revenues	16,075	10,247
Elimination of intersegment revenues	(206)	(153)
Gain on U.K. natural gas contracts	-	82
Total revenues	$ 15,869	$ 10,176
Items included in both revenues and costs and expenses:		
Consumer excise taxes on petroleum products and merchandise	$ 1,212	$ 1,174

E&P segment revenues increased $1,081 million in the first quarter of 2010 from the comparable prior-year period primarily a result of higher liquid hydrocarbon and natural gas price realizations. Liquid hydrocarbon realizations averaged $74.35 per barrel in the first quarter of 2010 compared to $40.20 in the first quarter of 2009, while natural gas realizations averaged $3.31 and $2.82 per mcf in the same periods. Revenues included gains on derivatives of $51 million in the first quarter of 2010, of which $30 million were unrealized.

Net sales volumes during the quarter averaged 361 mboepd, compared to 393 mboepd for the same period last year. This 8 percent decrease in sales volumes reflects the liquid hydrocarbon and natural gas production declines previously discussed.

For the first quarter of 2009, losses of $82 million were excluded from E&P segment revenues related to natural gas sales contracts in the U.K. that are accounted for as derivative instruments. Those contracts expired in 2009.

The tables on the following page report E&P segment realizations and sales volumes in greater detail for both quarters.

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	Three Months Ended March 31,	
	2010	2009
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)		
United States	58	66
Europe	85	73
Africa	83	85
Total International	168	158
Worldwide Continuing Operations	226	224
Discontinued Operations(a)	-	-
Worldwide	226	224
Natural Gas Sales (mmcfd)		
United States	351	425
Europe(b)	109	159
Africa	353	433
Total International	462	592
Worldwide Continuing Operations	813	1,017
Discontinued Operations(a)	-	64
Worldwide	813	1,081
Total Worldwide Sales (mboepd)		
Continuing Operations	361	393
Discontinued Operations(a)	-	11
Worldwide	361	404

	Three Months Ended March 31,	
	2010	2009
E&P Operating Statistics		
Average Realizations (c)		
Liquid Hydrocarbons (per bbl)		
United States	$72.46	$36.60
Europe	78.95	47.59
Africa	70.96	36.70
Total International	75.01	41.71
Worldwide Continuing Operations	74.35	40.20
Discontinued Operations	-	-
Worldwide	$74.35	$40.20
Natural Gas (per mcf)		
United States	$5.49	$4.49

Europe	6.17	5.36
Africa	0.25	0.25
Total International	1.65	1.62
Worldwide Continuing Operations	3.31	2.82
Discontinued Operations	-	8.60
Worldwide	$3.31	$3.16

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

(b) Includes natural gas acquired for injection and subsequent resale of 25 mmcfd and 24 mmcfd for the first three 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.

OSM segment revenues increased $43 million in the first quarter of 2010 from the comparable prior-year period. The increase was driven primarily by a 92 percent increase in average realizations. Net synthetic crude sales for the first quarter of 2010 were 25 mbpd at an average realized price of $73.76 per barrel compared to 32 mbpd at $38.49 in the same period of 2009. The decreased sales volumes reflect lower volumes sold as a result of previously discussed turnaround and the buildup of bitumen required for the AOSP Expansion 1.

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Revenues in both periods include the impact of derivative instruments intended to mitigate price risk related to future sales of synthetic crude. Included in segment revenues was a net loss of $10 million on crude oil derivative instruments in the first quarter of 2010 versus a net gain $8 million for the same period in 2009.

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

RM&T segment revenues increased $4,688 million in the first quarter of 2010 from the comparable prior-year period. While our overall refined product sales volumes in the first quarter of 2010 were relatively unchanged compared to the same period of 2009 our refined product and liquid hydrocarbon selling prices were higher as illustrated by the wholesale benchmark prices on the table below.

	Three Months Ended March 31,	
(Dollars per gallon)	2010	2009
Chicago Spot Unleaded regular gasoline	$2.02	$1.23
Chicago Spot Ultra-low sulfur diesel	2.04	1.30
USGC Spot Unleaded regular gasoline	2.05	1.22
USGC Spot Ultra-low sulfur diesel	$2.06	$1.33

Income from equity method investments increased $58 million in the first quarter of 2010 from the comparable prior-year period. Higher commodity prices in the first quarter of 2010 compared to the same period of 2009 positively impacted the earnings of many of our equity method investees.

Net gain on disposal of assets was the sale of a 20 percent outside-operated undivided interest in our E&P segment's the 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.

Cost of revenues increased $5,524 million in the first quarter of 2010 from the comparable prior-year period. The increase resulted primarily from higher acquisition costs of crude oil, refinery charge and blendstocks and purchased refined products in the RM&T segment. Increased volumes of purchased refined products also contributed to the increase. In addition, higher turnaround costs of $180 million in the RM&T and OSM segments contributed to increased cost of revenues compared to prior year.

Depreciation, depletion and amortization ("DD&A") decreased $11 million in the first quarter of 2010 compared to the same quarter of 2009. Decreased DD&A related to the lower sales volumes in our E&P and OSM segments were mostly offset by increased DD&A related to the Garyville expansion being put in to service.

Long-lived asset impairments in the first quarter of 2010 were primarily related to the Powder River Basin. In March 2010, our reservoir study concluded and a portion of our Powder River Basin field was removed from our plans for future development, resulting in $423 million impairment (see Note 11).

Exploration expenses were $98 million in the first quarter of 2010, including expenses related to dry wells of $32 million, primarily in Alaska and Equatorial Guinea. Exploration expenses were $62 million in the first quarter of

2009, including expenses related to dry wells of $4 million, primarily related to offshore drilling.

Provision for income taxes increased $256 million in the first quarter of 2010 from the comparable period of 2009 primarily due to the increase in pretax income. The effective income tax rate also increased as a result of tax legislation changes, see Note 8.

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

	Three Months Ended March 31,			
	2010		2009	
Statutory U.S. income tax rate	35	%	35	%
Effects of foreign operations, including foreign tax credits	14		13	
State and local income taxes, net of federal income tax effects	(1	)	1	
Legislation change	5		-	
Effective income tax rate for continuing operations	53	%	49	%

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Segment Results

Segment income is summarized in the following table:

	Three Months Ended March 31,	
(In millions)	2010	2009
E&P		
United States	$109	$(52)
International	393	135
E&P segment	502	83
OSM	(17)	(24)
IG	44	27
RM&T	(237)	159
Segment income	292	245
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(10)	(50)
Foreign currency remeasurement of taxes	33	28
Gain on disposition	449	-
Long-lived asset impairment	(262)	-
Deferred income taxes - tax legislation changes	(45)	-
Gain (loss) on U.K. natural gas contracts	-	42
Discontinued operations	-	17
Net income	$457	$282

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".

United States E&P income increased $161 million in the first quarter of 2010 compared to the same period of 2009. The increase is primarily related to a 98 percent increase in liquid hydrocarbon realizations. Partially offsetting the increase were lower liquid hydrocarbon sales volumes from the Gulf of Mexico due to normal production declines and lower natural gas and natural gas liquid sales volumes realized due to the Permian Basin divestitures. DD&A expense decreased approximately $35 million, pretax, as a result of lower sales volumes.

International E&P income increased $258 million in the first quarter of 2010 compared to the same period of 2009. This increase in income is primarily related to an 80 percent increase in liquid hydrocarbon realizations and increased liquid hydrocarbon sales volumes from Europe. Partially offsetting the impact of realizations was increased exploration expenses.

OSM segment reported a loss of $17 million in the first quarter of 2010 compared to a loss of $24 million in the first quarter 2009. The smaller segment loss in the first quarter of 2010 was primarily related to higher realizations, with a 92 percent improvement in realizations compared to the first quarter of 2009. This was offset by lower volumes produced as a result of the previously discussed turnaround and the buildup of bitumen required for the AOSP

Expansion 1. We incurred pretax incremental costs of $30 million related to the turnaround that began in March 2010. In addition, revenues in both periods were impacted by derivatives with a net loss of $10 million in the first quarter of 2010 versus a net gain $8 million for the same period in 2009.

RM&T segment income decreased $396 million in the first quarter of 2010 compared to the same period of 2009. The income decrease was primarily a result of a lower refining and wholesale marketing gross margin, which was a negative 5.69 cents per gallon in the first quarter of 2010 compared to a positive 7.92 cents per gallon in the comparable period of 2009. Several factors contributed to the lower first quarter 2010. We incurred incrementally higher crude oil costs due to lower sweet/sour differentials and increased domestic crude oil acquisition costs. In addition, manufacturing costs were higher due to a combination of increased planned turnaround costs and higher depreciation expense related to the Garyville expansion units now being in service. Turnaround costs included in the gross margin increased by a pretax $150 million in the first quarter of 2010 compared to the same period of 2009.

Our refining and wholesale marketing gross margin also included pretax derivative losses of $23 million in the first quarter of 2010 compared to losses of $60 million in the first quarter of 2009.

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IG segment income increased $17 million in the first quarter of 2010 compared to the same period of 2009. Decreased spending on natural gas technology research was the primary reason for the increase in income. Despite a planned turnaround at the Equatorial Guinea gas production facilities, which significantly reduced natural gas volumes to the LNG and methanol facilities during the quarter, we were was able to take advantage of higher LNG and methanol prices through the sale of inventories in Equatorial Guinea.

Cash Flows and Liquidity

Cash Flows

Net cash provided by operating activities totaled $849 million in the first three months of 2010, compared to $839 million in the first three months of 2009.

Net cash used in investing activities totaled $10 million in the first three months of 2010, compared to $1,558 million in the first three 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, $1.3 billion proceeds on this sale, approximated the amounts we spent on property, plant and equipment additions in the quarter.

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.

Net cash used in financing activities was $172 million in the first three months of 2010, compared to net cash provided by financing activities of $1,307 million in the first three months of 2009. Dividends paid were a significant use of cash in all periods. Sources of cash in the first three months of 2009 included the issuance of $1.5 billion in senior notes.

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, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program, and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

At March 31, 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 26, 2007, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

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Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 21 percent at March 31, 2010, compared to 23 percent at December 31, 2009. This includes $337 million of debt that is serviced by United States Steel.

(In millions)	March 31, 2010	December 31, 2009
Long-term debt due within one year	$98	$96
Long-term debt	8,440	8,436
Total debt	$8,538	$8,532
Cash	$2,718	$2,057
Equity	$22,227	$21,910
Calculation:		
Total debt	$8,538	$8,532
Minus cash	2,718	2,057
Total debt minus cash	$5,820	$6,475
Total debt	8,538	8,532
Plus equity	22,227	21,910
Minus cash	2,718	2,057
Total debt plus equity minus cash	$28,047	$28,385
Cash-adjusted debt-to-capital ratio	21 %	23 %

Capital Requirements

On April 28, 2010, our Board of Directors approved a 25 cents per share dividend, payable June 10, 2010 to stockholders of record at the close of business on May 19, 2010. This represents a 4 percent increase in our quarterly dividend from 24 cents per share of common stock.

In April 2010, we repurchased $500 million in aggregate principal of our debt under two tender offers. Additional information on this debt repurchase can be found in Note 13.

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 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.

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Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of March 31, 2010.

(In millions)	Total	2010	2011-2012	2013-2014	Later Years
Long-term debt (excludes interest)(a)	$8,191	$68	$1,671	$1,044	$5,408
Sale-leaseback financing(a)	33	11	22	-	-
Capital lease obligations(a)	660	23	81	88	468
Operating lease obligations(a)	847	102	247	183	315
Operating lease obligations under sublease(a)	15	3	12	-	-
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts	8,655	6,981	1,054	459	161
Transportation and related contracts	2,202	307	404	254	1,237
Contracts to acquire property, plant and equipment	2,850	1,860	965	18	7
LNG terminal operating costs(b)	140	10	25	26	79
Service and materials contracts(c)	2,012	277	469	328	938
Unconditional purchase obligations(d)	47	8	16	16	7
Commitments for oil and gas exploration (non-capital)(e)	36	28	1	1	6
Total purchase obligations	15,942	9,471	2,934	1,102	2,435
Other long-term liabilities reported in the consolidated balance sheet(f)	2,300	81	643	560	1,016
Total contractual cash obligations(g)	$27,988	$9,759	$5,610	$2,977	$9,642

(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.

(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.

Receivable from United States Steel

We remain obligated (primarily or contingently) for $337 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 March 31, 2010 that it believes that its liquidity will be adequate to satisfy its obligations for the foreseeable future. United States Steel's senior unsecured debt ratings are BB by Standard and Poor's Corporation, Ba2 by Moody's Investment Service, Inc. and BB+ by Fitch Ratings. The ratings listed reflect a Moody's upgrade from Ba3 to Ba2 in March 2010.

Critical Accounting Estimates

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

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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 estimate that we may spend approximately $1 billion over a six -year period that began in 2008 to comply with Mobile Source Air Toxics II ("MSAT II") regulations relating to benzene content in refined products. We have not finalized our strategy or cost estimates to comply with these requirements. Our actual MSAT II expenditures since inception have totaled $343 million through March 31, 2010, with $60 million in the first 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.

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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 Note 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 March 31, 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				
Crude oil	$ (46)	$ (115)	$ 46	$ 115
Natural gas	(8)	(21)	8	21
OSM Segment				
Crude oil	$ (40)	$ (99)	$ 40	$ 99
RM&T Segment				
Crude oil	$ (38)	$ (96)	$ 61	$ 163
Natural gas	1	2	(1)	(2)
Refined products	16	38	(16)	(40)

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 March 31, 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 March 31,	
(In millions)	2010	2009
Segment Income (Loss)		
Exploration and Production		
United States	$109	$(52)
International	393	135
E&P segment	502	83
Oil Sands Mining	(17)	(24)
Integrated Gas	44	27
Refining, Marketing and Transportation	(237)	159
Segment income	292	245
Items not allocated to segments, net of income taxes	165	37
Net income	$457	$282
Capital Expenditures(a)		
Exploration and Production		
United States	$458	$230
International	145	135
E&P segment	603	365
Oil Sands Mining	265	286
Integrated Gas	1	-
Refining, Marketing and Transportation	310	660
Discontinued Operations(b)	-	24
Corporate	-	1
Total	$1,179	$1,336
Exploration Expenses		
United States	$46	$34
International	52	28
Total	$98	$62

(a) Capital expenditures include changes in accruals.

(b) Our businesses in Ireland and Gabon were sold in 2009. All periods of 2009 have been recast to reflect these businesses as discontinued operations.

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MARATHON OIL CORPORATION

Supplemental Statistics (Unaudited)

	Three Months Ended March 31,	
	2010	2009
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)		
United States	58	66
Europe	85	73
Africa	83	85
Total International	168	158
Worldwide Continuing Operations	226	224
Discontinued Operations	-	-
Worldwide	226	224
Natural Gas Sales (mmcfd)		
United States	351	425
Europe(c)	109	159
Africa	353	433
Total International	462	592
Worldwide Continuing Operations	813	1,017
Discontinued Operations	-	64
Worldwide	813	1,081
Total Worldwide Sales (mboepd)		
Continuing Operations	361	393
Discontinued Operations	-	11
Worldwide	361	404
Average Realizations (d)		
Liquid Hydrocarbons (per bbl)		
United States	$72.46	$36.60
Europe	78.95	47.59
Africa	70.96	36.70
Total International	75.01	41.71
Worldwide Continuing Operations	74.35	40.20
Discontinued Operations	-	-
Worldwide	$74.35	$40.20
Natural Gas (per mcf)		
United States	$5.49	$4.49

Europe	6.17	5.36
Africa(e)	0.25	0.25
Total International	1.65	1.62
Worldwide Continuing Operations	3.31	2.82
Discontinued Operations	-	8.60
Worldwide	$3.31	$3.16

(c) Includes natural gas acquired for injection and subsequent resale of 25 mmcfd and 24 mmcfd for the first three months of 2010 and 2009.

(d) Excludes gains and losses on derivative instruments, including the unrealized effects of U.K. natural gas sales contracts that were 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)

(In millions, except as noted)	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
OSM Operating Statistics		
Net Synthetic Crude Oil Sales (mbpd) (f)	25	32
Synthetic Crude Oil Average Realization (per bbl)(g)	$73.76	$38.49
IG Operating Statistics		
Net Sales (mtpd) (h)		
LNG	5,792	6,769
Methanol	1,158	1,153
RM&T Operating Statistics		
Refinery Runs (mbpd)		
Crude oil refined	1,003	851
Other charge and blendstocks	97	220
Total	1,100	1,071
Refined Product Yields (mbpd)		
Gasoline	576	617
Distillates	306	309
Propane	20	21
Feedstocks and special products	116	50
Heavy fuel oil	14	23
Asphalt	77	65
Total	1,109	1,085
Refined Products Sales Volumes (mbpd) (i)	1,355	1,286
Refining and Wholesale Marketing Gross Margin (per gallon) (j)	$(0.0569)	$0.0792
Speedway SuperAmerica		
Retail outlets	1,598	1,612
Gasoline and distillate sales (millions of gallons)	783	784
Gasoline and distillate gross margin (per gallon)	$0.1195	$0.1068
Merchandise sales	$731	$690
Merchandise gross margin	$178	$178

(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

We are a defendant, along with other refining companies, in 27 cases arising in four states alleging damages for MTBE contamination. We finalized the settlement of 25 of those cases that were pending in the state and federal courts of New York and Florida. These cases have been dismissed by the respective courts. The settlement did not significantly impact our consolidated results of operations, financial positions, or cash flows. Two new MTBE cases were filed against us. The Village of Bethalto, Illinois filed suit in the state court of Madison County, IL and 6 municipalities and a county in Maryland filed suit in Baltimore County, MD. We expect additional MTBE lawsuits 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. In addition, we have been working on certain agreed-upon supplemental environmental projects as part of this settlement of an enforcement action for alleged CAA violations and these have been completed. As part of this consent decree, we were required to conduct evaluations of refinery benzene waste air pollution programs (benzene waste “NESHAPS”). Subject to entering a formal consent decree or further amendment of the New Source Review consent decree to memorialize our understanding, 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 lodged with the Court on March 19, 2010 and is expected to be finalized during second quarter 2010.

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 two updates to our risk factors are as follows:

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

Our offshore exploration and development operations represent increased technological challenges and operating risks, primarily associated with the marine environment. Because deepwater areas are typically farther from land than shallow water areas, operating in deepwater areas pose incrementally greater risks because these projects often lack proximity to the physical and oilfield service infrastructure present in shallower waters. Environmental remediation and other costs resulting from oil spills or releases of hazardous materials may result in substantial liabilities and could materially and adversely affect our business, financial condition, results of operations and cash flow and the market value of our securities.

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.

As we discussed in our annual 10-K report, 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:

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- EPA issued a finding in 2009 that greenhouse gases contribute to air pollution that endangers public health and welfare. Trade groups to which Marathon belongs, several states and others have filed legal challenges to this endangerment finding in the D.C. Circuit Court of Appeals. A decision is not expected in this case for about two years. Related to the 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 will lead to widespread regulation of stationary sources of greenhouse gas emissions starting in 2012 and the EPA is expected to issue a so-called tailoring rule in the second quarter of 2010 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. Legal challenges are also expected to the emission standard for mobile sources and the tailoring rule.

- 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.

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

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased (a)(b)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (d)	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (d)
01/01/10 – 01/31/10	9,361	$31.90	-	$2,080,366,711
02/01/10 – 02/28/10	3,450	$30.33	-	$2,080,366,711
03/01/10 – 03/31/10	47,184 (c)	$31.20	-	$2,080,366,711
Total	59,995	$31.26	-	

(a) 12,811 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 shares based on a value of $52.17 per share. In the first quarter of 2010, we acquired 2 fractional shares due to acquisition share exchanges and Ashland share transfers pending at the closing of the transaction.

(c) 47,182 shares were purchased 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 March 31, 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

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

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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.

May 10, 2010	MARATHON OIL CORPORATION
	By: /s/ Michael K. Stewart Michael K. Stewart Vice President, Accounting and Controller