MARATHON OIL CORP
Form 10-Q
November 08, 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 September 30, 2010

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission file number 1-5153

Marathon Oil Corporation
(Exact name of registrant as specified in its charter)

Delaware	25-0996816
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Road, Houston, TX 77056-2723
(Address of principal executive offices)

(713) 629-6600
(Registrant's telephone number, including area code)

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

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

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

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

Large accelerated filer x		Accelerated filer
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 o No ξ

There were 709,911,592 shares of Marathon Oil Corporation common stock outstanding as of October 29, 2010.

MARATHON OIL CORPORATION
Form 10-Q
Quarter Ended September 30, 2010

INDEX

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

Part I - Financial Information

Item 1. Financial Statements

MARATHON OIL CORPORATION

Consolidated Statements of Income (Unaudited)

(In millions, except per share data)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenues and other income:				
Sales and other operating revenues (including consumer excise taxes)	$ 18,407	$ 14,335	$ 52,673	$ 37,509
Sales to related parties	36	27	88	68
Income from equity method investments	95	75	301	184
Net gain on disposal of assets	5	5	830	200
Other income	32	35	77	112
Total revenues and other income	18,575	14,477	53,969	38,073
Costs and expenses:				
Cost of revenues (excludes items below)	14,291	10,963	41,464	28,080
Purchases from related parties	180	133	454	338
Consumer excise taxes	1,351	1,258	3,871	3,658
Depreciation, depletion and amortization	765	627	2,072	1,970
Long-lived asset impairments	-	3	467	18
Selling, general and administrative expenses	324	323	958	935
Other taxes	99	98	324	296
Exploration expenses	59	55	282	181
Total costs and expenses	17,069	13,460	49,892	35,476
Income from operations	1,506	1,017	4,077	2,597
Net interest and other financing costs	(27)	(35)	(75)	(63)
Loss on early extinguishment of debt	-	-	(92)	-
Income from continuing operations before income taxes	1,479	982	3,910	2,534
Provision for income taxes	783	590	2,048	1,549
Income from continuing operations	696	392	1,862	985
Discontinued operations	-	21	-	123
Net income	$ 696	$ 413	$ 1,862	$ 1,108

Per Share Data

Basic:				
Income from continuing operations	$ 0.98	$ 0.55	$ 2.63	$ 1.39
Discontinued operations	$ -	$ 0.03	$ -	$ 0.17
Net income per share	$ 0.98	$ 0.58	$ 2.63	$ 1.56
Diluted:				
Income from continuing operations	$ 0.98	$ 0.55	$ 2.62	$ 1.39
Discontinued operations	$ -	$ 0.03	$ -	$ 0.17
Net income per share	$ 0.98	$ 0.58	$ 2.62	$ 1.56
Dividends paid	$ 0.25	$ 0.24	$ 0.74	$ 0.72

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

2

MARATHON OIL CORPORATION

Consolidated Balance Sheets (Unaudited)

(In millions, except per share data)	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$1,643	$2,057
Receivables, less allowance for doubtful accounts of $18 and $14	5,363	4,677
Receivables from related parties	53	60
Inventories	3,969	3,622
Other current assets	572	221
Total current assets	11,600	10,637
Equity method investments	1,844	1,970
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $19,027 and $17,185	31,987	32,121
Goodwill	1,383	1,422
Other noncurrent assets	1,309	902
Total assets	$48,123	$47,052
Liabilities		
Current liabilities:		
Accounts payable	$6,775	$6,982
Payables to related parties	59	64
Payroll and benefits payable	362	399
Accrued taxes	1,407	547
Deferred income taxes	414	403
Other current liabilities	489	566
Long-term debt due within one year	98	96
Total current liabilities	9,604	9,057
Long-term debt	7,844	8,436
Deferred income taxes	3,940	4,104
Defined benefit postretirement plan obligations	1,846	2,056
Asset retirement obligations	1,166	1,099
Deferred credits and other liabilities	367	390
Total liabilities	24,767	25,142
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – zero and 5 million shares issued, zero and 1 million shares outstanding (no par value, 26 million shares authorized)	-	-
Common stock:		
Issued – 770 million and 769 million shares (par value		

$1 per share, 1.1 billion shares authorized)	770	769
Securities exchangeable into common stock – zero and 5 million shares issued, zero and 1 million shares outstanding (no par value, 29 million authorized)	-	-
Held in treasury, at cost – 60 million and 61 million shares	(2,681)	(2,706)
Additional paid-in capital	6,756	6,738
Retained earnings	19,379	18,043
Accumulated other comprehensive loss	(868)	(934)
Total stockholders' equity	23,356	21,910
Total liabilities and stockholders' equity	$48,123	$47,052

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

3

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows (Unaudited)

(In millions)	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Increase (decrease) in cash and cash equivalents		
Operating activities:		
Net income	$ 1,862	$ 1,108
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on early extinguishment of debt	92	-
Discontinued operations	-	(123)
Deferred income taxes	(228)	726
Depreciation, depletion and amortization	2,072	1,970
Long-lived asset impairments	467	18
Pension and other postretirement benefits, net	(65)	(159)
Exploratory dry well costs and unproved property impairments	122	48
Net gain on disposal of assets	(830)	(200)
Equity method investments, net	4	42
Changes in:		
Current receivables	(668)	(1,241)
Inventories	(665)	(184)
Current accounts payable and accrued liabilities	757	1,141
All other operating, net	68	78
Net cash provided by continuing operations	2,988	3,224
Net cash provided by discontinued operations	-	84
Net cash provided by operating activities	2,988	3,308
Investing activities:		
Additions to property, plant and equipment	(3,634)	(4,749)
Disposal of assets	1,370	573
Trusteed funds - withdrawals	-	16
Investing activities of discontinued operations	-	(69)
All other investing, net	8	63
Net cash used in investing activities	(2,256)	(4,166)
Financing activities:		
Borrowings	-	1,491
Debt issuance costs	-	(11)
Debt repayments	(628)	(43)
Dividends paid	(526)	(510)
All other financing, net	8	(1)
Net cash provided by (used in) financing activities	(1,146)	926
Effect of exchange rate changes on cash:		
Continuing operations	-	19
Discontinued operations	-	(2)
Total effect of exchange rate changes on cash	-	17
Net increase (decrease) in cash and cash equivalents	(414)	85
Cash and cash equivalents at beginning of period	2,057	1,285
Cash and cash equivalents at end of period	$ 1,643	$ 1,370

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

MARATHON OIL CORPORATION

Consolidated Statements of Comprehensive Income (Unaudited)

(In millions)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income	$ 696	$ 413	$ 1,862	$ 1,108
Other comprehensive income (loss)				
Post-retirement and post-employment plans				
Change in actuarial gain (loss)	(24)	9	134	58
Income tax provision on post-retirement and post-employment plans	10	-	(73)	(31)
Post-retirement and post-employment plans, net of tax	(14)	9	61	27
Derivative hedges				
Net unrecognized gain	1	19	5	22
Income tax benefit (provision) on derivatives	-	(4)	-	(11)
Derivative hedges, net of tax	1	15	5	11
Foreign currency translation and other				
Unrealized gain (loss)	(1)	-	(1)	1
Income tax provision on foreign currency translation and other	1	-	1	-
Foreign currency translation and other, net of tax	-	-	-	1
Other comprehensive income (loss)	(13)	24	66	39
Comprehensive income	$ 683	$ 437	$ 1,928	$ 1,147

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

MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These consolidated financial statements are unaudited; however, in the opinion of management, these statements reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements. Certain reclassifications have been made to conform to current year presentation.

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

2. Accounting Standards

Recently Adopted

Variable interest accounting standards were amended by the Financial Accounting Standards Board ("FASB") in June 2009. The new accounting standards replace the 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 standards require 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 these standards in the first quarter of 2010 did not have a significant impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 3.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. We adopted all aspects of this standard in the first quarter of 2010. 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 us as of December 31, 2009. The SEC introduced a new definition of oil and gas producing activities which allows companies to include volumes in their reserve base from unconventional resources. The FASB also addresses the impact of changes in the SEC's rules and definitions on accounting for oil and gas producing activities. Initial adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The effect on depreciation, depletion and amortization expense subsequent to adoption, 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 September 30, 2010. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a VIE. We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore, the Corridor Pipeline is not consolidated. Our maximum exposure to loss as a

Notes to Consolidated Financial Statements (Unaudited)

result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $832 million as of September 30, 2010. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month's activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

4. Income per Common Share

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

	Three Months Ended September 30,			
	2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 696	$ 696	$ 392	$ 392
Discontinued operations	-	-	21	21
Net income	$ 696	$ 696	$ 413	$ 413
Weighted average common shares outstanding	710	710	709	709
Effect of dilutive securities	-	2	-	2
Weighted average common shares, including dilutive effect	710	712	709	711
Per share:				
Income from continuing operations	$ 0.98	$ 0.98	$ 0.55	$ 0.55
Discontinued operations	$ -	$ -	$ 0.03	$ 0.03
Net income	$ 0.98	$ 0.98	$ 0.58	$ 0.58

	Nine Months Ended September 30,			
	2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,862	$ 1,862	$ 985	$ 985
Discontinued operations	-	-	123	123
Net income	$ 1,862	$ 1,862	$ 1,108	$ 1,108
Weighted average common shares outstanding	709	709	709	709
Effect of dilutive securities	-	2	-	2
Weighted average common shares, including dilutive effect	709	711	709	711
Per share:				
	$ 2.63	$ 2.62	$ 1.39	$ 1.39

Income from continuing operations				
Discontinued operations	$ -	$ -	$ 0.17	$ 0.17
Net income	$ 2.63	$ 2.62	$ 1.56	$ 1.56

The per share calculations above exclude 11 million and 12 million stock options and stock appreciation rights for the third quarter and the first nine months of 2010, as they were antidilutive. Excluded in the third quarter and the first nine months of 2009 were 11 million and 10 million stock options and stock appreciation rights.

5. Dispositions

Assets Held For Sale

In October 2010, we entered into definitive agreements to sell our Refining, Marketing and Transportation ("RM&T") segment's St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 Speedway SuperAmerica retail outlets, plus related inventories. The fair value of the consideration is estimated to be approximately $900 million, which includes the estimated value of inventory and the fair values of (1) a retained preferred stock interest in the buyer with a stated value of $80 million, (2) a maximum $125 million earnout provision payable to us over eight years, and (3) a maximum $60 million of margin support payable to

Notes to Consolidated Financial Statements (Unaudited)

the buyer over two years. Cash proceeds at closing are estimated to be $700 million. The earnout and margin support provisions in the agreements are subject to certain conditions and any margin support paid may be recovered by an increase in the total earnout amount. We expect the sale transaction to close by yearend 2010, contingent upon the buyer meeting the conditions of their financing arrangements and other customary closing conditions.

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

(In millions)	
Other current assets	$308
Other noncurrent assets	512
Total assets	820
Deferred credits and other liabilities	3
Total liabilities	$3

2010 Disposition

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

2009 Dispositions

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

In June 2009, we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. An initial $100 million payment was made at closing. Additional fixed proceeds of $135 million will be received on the earlier of first commercial gas or December 31, 2012. Including contingent consideration, the fair value of $311 million at June 30, 2009, was less than book value. An impairment of $154 million was recognized in the second quarter of 2009 and reported as part of the loss on disposal of discontinued operations.

Existing guarantees of our subsidiaries' performance issued to Irish government entities remain in place after the sales until the purchasers issue similar guarantees to replace them. The guarantees, related to asset retirement obligations and natural gas production levels, have been indemnified by the purchasers. The fair value of these guarantees is not significant.

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

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

(In millions)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Revenues applicable to discontinued operations	$ 65	$ 186
Pretax income from discontinued operations	48	98
Pretax loss on disposal of discontinued operations	$ -	$ 14

In June 2009, we closed sales of a portion of our operated and all of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded. Activities related to these properties had been reported in our E&P segment.

Notes to Consolidated Financial Statements (Unaudited)

6. Segment Information

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

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

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

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

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

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

	Three Months Ended September 30, 2010				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$ 2,343	$ 156	$ 38	$ 15,870	$ 18,407
Intersegment (a)	174	34	-	6	214
Related parties	15	-	-	21	36
Segment revenues	2,532	190	38	15,897	18,657
Elimination of intersegment revenues	(174)	(34)	-	(6)	(214)
Total revenues	$ 2,358	$ 156	$ 38	$ 15,891	$ 18,443
Segment income	$ 510	$ 18	$ 41	$ 285	$ 854
Income from equity method investments(b)	51	-	51	18	120
Depreciation, depletion and amortization (c)	491	28	1	234	754
Income tax provision (b)	579	2	21	170	772
Capital expenditures (c)(d)	586	191	1	273	1,051

	Three Months Ended September 30, 2009				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$ 1,816	$ 130	$ 15	$ 12,387	$ 14,348
Intersegment (a)	148	37	-	8	193
Related parties	15	-	-	12	27
Segment revenues	1,979	167	15	12,407	14,568
	(148)	(37)	-	(8)	(193)

Elimination of intersegment revenues					
Loss on U.K. natural gas contracts(e)	(13)	-	-	-	(13)
Total revenues	$ 1,818	$ 130	$ 15	$ 12,399	$ 14,362
Segment income	$ 491	$ 25	$ 13	$ 158	$ 687
Income from equity method investments	40	-	21	14	75
Depreciation, depletion and amortization (c)	424	26	1	167	618
Income tax provision(b)	297	7	12	119	435
Capital expenditures (c)(d)	516	267	-	634	1,417

9

Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30, 2010				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$ 7,144	$ 461	$ 98	$ 44,970	$ 52,673
Intersegment (a)	498	73	-	37	608
Related parties	41	-	-	47	88
Segment revenues	7,683	534	98	45,054	53,369
Elimination of intersegment revenues	(498)	(73)	-	(37)	(608)
Total revenues	$ 7,185	$ 461	$ 98	$ 45,017	$ 52,761
Segment income (loss)	$ 1,444	$ (59)	$ 109	$ 469	$ 1,963
Income from equity method investments(b)	128	-	142	56	326
Depreciation, depletion and amortization (c)	1,279	67	3	695	2,044
Income tax provision (benefit)(b)	1,741	(15)	56	274	2,056
Capital expenditures (c)(d)	1,774	699	2	839	3,314

	Nine Months Ended September 30, 2009				
(In millions)	E&P	OSM	IG	RM&T	Total
Revenues:					
Customer	$ 4,952	$ 353	$ 33	$ 32,099	$ 37,437
Intersegment (a)	390	91	-	25	506
Related parties	44	-	-	24	68
Segment revenues	5,386	444	33	32,148	38,011
Elimination of intersegment revenues	(390)	(91)	-	(25)	(506)
Gain on U.K. natural gas contracts(e)	72	-	-	-	72
Total revenues	$ 5,068	$ 353	$ 33	$ 32,123	$ 37,577
Segment income	$ 782	$ 3	$ 53	$ 482	$ 1,320
Income from equity method investments	77	-	91	16	184
Depreciation, depletion and amortization (c)	1,373	97	3	476	1,949
Income tax provision (benefit)(b)	910	(1)	27	329	1,265
Capital expenditures (c)(d)	1,490	834	1	2,007	4,332

(a) Management believes intersegment transactions were conducted under terms comparable to those with unrelated parties.
(b) Differences between segment totals and our financial statement totals represent amounts related to corporate administrative activities and other unallocated items and are included in “Items not allocated to segments, net of income taxes” in the reconciliation below.
(c) Differences between segment totals and our financial statement totals represent amounts related to corporate administrative activities.

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

Notes to Consolidated Financial Statements (Unaudited)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Segment income	$ 854	$ 687	$ 1,963	$ 1,320
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(106)	(159)	(178)	(299)
Foreign currency remeasurement of income taxes	(37)	(114)	33	(180)
Gain (loss) on dispositions (a)	-	(15)	449	107
Impairments(b)	(15)	-	(303)	-
Loss on early extinguishment of debt(c)	-	-	(57)	-
Deferred income taxes - tax legislation changes(d)	-	-	(45)	-
Gain on U.K. natural gas contracts	-	(7)	-	37
Discontinued operations	-	21	-	123
Net income	$ 696	$ 413	$ 1,862	$ 1,108

(a) Additional information on these gains can be found in Note 5.
(b) Impairments include those based upon fair value measurements discussed in Note 11 and a $15 million pretax writeoff of the remaining portion of the contingent proceeds from the 2009 sale of the Corrib natural gas development, which was recorded in the second quarter of 2010, based upon new public information regarding the pipeline that would transport natural gas from the Corrib development.
(c) Additional information on debt retired early can be found in Note 13.
(d) A discussion of the tax legislation changes can be found in Note 8.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Total revenues	$ 18,443	$ 14,362	$ 52,761	$ 37,577
Less: Sales to related parties	36	27	88	68
Sales and other operating revenues (including consumer excise taxes)	$ 18,407	$ 14,335	$ 52,673	$ 37,509

7. Defined Benefit Postretirement Plans

The following summarizes the components of net periodic benefit cost:

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2010	2009	2010	2009
Service cost	$ 27	$ 36	$ 4	$ 4
Interest cost	44	42	10	11
Expected return on plan assets	(40)	(41)	-	-
Amortization:				
– prior service cost (credit)	4	4	(1)	(1)
– actuarial loss (gain)	24	8	(1)	(2)
– net settlement	12	-	-	-
Net periodic benefit cost	$ 71	$ 49	$ 12	$ 12

11

Notes to Consolidated Financial Statements (Unaudited)

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2010	2009	2010	2009
Service cost	$81	$108	$13	$13
Interest cost	131	126	29	31
Expected return on plan assets	(120)	(121)	-	-
Amortization:				
– prior service cost (credit)	10	11	(4)	(4)
– actuarial loss (gain)	74	24	(2)	(4)
– net settlement/curtailment loss	12	18	-	-
Net periodic benefit cost	$188	$166	$36	$36

During the first nine months of 2010, we made contributions of $240 million to our funded pension plans. We expect to make additional contributions up to an estimated $2 million to our funded pension plans over the remainder of 2010. Current benefit payments related to unfunded pension and other postretirement benefit plans were $29 million and $26 million during the first nine months of 2010.

8. Income Taxes

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

	Nine Months Ended September 30,	
	2010	2009
Statutory U.S. income tax rate	35 %	35 %
Effects of foreign operations, including foreign tax credits	17	25
State and local income taxes, net of federal income tax effects	-	1
Legislation change	1	-
Other	(1)	-
Effective income tax rate for continuing operations	52 %	61 %

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

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in the Corporate and other unallocated items line of the reconciliation shown in Note 6.

Notes to Consolidated Financial Statements (Unaudited)

9. Inventories

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

(In millions)	September 30, 2010	December 31, 2009
Liquid hydrocarbons, natural gas and bitumen	$ 1,555	$ 1,393
Refined products and merchandise	2,046	1,790
Supplies and sundry items	368	439
Inventories	$ 3,969	$ 3,622

10. Property, Plant and Equipment

(In millions)	September 30, 2010	December 31, 2009
E&P		
United States	$6,118	$6,005
International	4,964	5,522
Total E&P	11,082	11,527
OSM	9,100	8,531
IG	35	34
RM&T	11,628	11,887
Corporate	142	142
Property, plant and equipment	$31,987	$32,121

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

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

In the first quarter of 2010, a detailed study of the commerciality of the Gardenia well in Equatorial Guinea concluded that development of the area was uncertain; therefore, we wrote off $20 million in costs associated with the well. 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.

13

Notes to Consolidated Financial Statements (Unaudited)

11. Fair Value Measurements

Fair Values - Recurring

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

	September 30, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 149	$ 23	$ 1	$ 90	263
Interest rate	-	45	-	-	45
Foreign currency	-	-	1	-	1
Derivative instruments, assets	149	68	2	90	309
Derivative instruments, liabilities					
Commodity	$ (207)	$ (1)	$ -	$ -	(208)
Derivative instruments, liabilities	(207)	(1)	-	-	(208)

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

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

Commodity derivatives in Level 3 are measured at fair value with a market approach using prices obtained from third-party services such 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, all these measures are considered Level 3.

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

14

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 September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Beginning balance	$(3)	$(29)	$9	$(26)
Total realized and unrealized gains (losses):				
Included in net income	4	19	23	63
Included in other comprehensive income	-	-	4	-
Transfers to Level 2	-	-	(30)	-
Purchases	-	1	2	1
Sales	-	-	-	(23)
Issuances	-	-	-	(44)
Settlements	1	8	(6)	28
Ending balance	$2	$(1)	$2	$(1)

Related to the derivatives in Level 3, net income for the third quarter and first nine months of 2010 included unrealized gains of $3 million related to instruments held at September 30, 2010. Net income for third quarter and first nine months of 2009 included unrealized gains of $4 million and unrealized losses of $20 million related to instruments held on those dates. See Note 12 for the income statement impacts of our derivative instruments.

Fair Values - Nonrecurring

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

	Three Months Ended September 30,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Equity method investment	$ -	$ 25	$ -	$ -

	Nine Months Ended September 30,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 146	$ 467	$ 5	$ 15
Long-lived assets held for sale	-	-	311	154
Equity method investment	-	25	-	-

In the third quarter of 2010, we fully impaired our Integrated Gas segment's equity method investment in an entity engaged in gas-to-fuels related technology. This investment was determined to have sustained an other than temporary loss in value. Based upon recent financial information, the fair value was measured with an income approach using internally developed estimates of future cash flows. These cash flows are Level 3 inputs.

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

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

Notes to Consolidated Financial Statements (Unaudited)

Several other long-lived assets held for use in our E&P segment were evaluated for impairment in the nine months ended September 30, 2010 and the comparable period of 2009 due to reduced drilling expectations, reduction of estimated reserves or declining natural gas prices. The fair values of the assets were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

The impairment charge recorded on assets held for sale in the second quarter of 2009 related to the sale of the Corrib natural gas development offshore Ireland and was based on a fair value of anticipated sale proceeds (see Note 5). Fair value of anticipated sale proceeds includes (1) $100 million received at closing, (2) $135 million minimum amount due at the earlier of first gas or December 31, 2012, and (3) a range of contingent proceeds subject to the timing of first gas. The fair value of the total proceeds was measured using an income method that incorporated a probability-weighted approach with respect to timing of first commercial gas and an associated sliding scale on the amount of corresponding consideration specified in the sales agreement: the longer it takes to achieve first gas, the lower the amount of the consideration. Because a portion of the proceeds is variable in timing and amount depending upon timing of first commercial gas, the inputs to the fair value calculation were classified as Level 3 inputs.

Fair Values – Reported

The following table summarizes financial instruments, excluding the derivative financial instruments, and their reported fair value by individual balance sheet line item at September 30, 2010 and December 31, 2009:

	September 30, 2010		December 31, 2009	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 23	$ 22	$ 23	$ 22
Other noncurrent assets	596	407	671	499
Total financial assets	619	429	694	521
Financial liabilities				
Long-term debt, including current portion(a)	8,628	7,563	8,754	8,190
Deferred credits and other liabilities	70	71	71	73
Total financial liabilities	$ 8,698	$ 7,634	$ 8,825	$ 8,263

(a) Excludes capital leases.

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

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

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

Over 90 percent of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions is used to measure the fair value of such debt. Because these quotes cannot be independently verified to the market they are considered Level 3 inputs. The fair value of our debt that is not publicly-

16

Notes to Consolidated Financial Statements (Unaudited)

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 September 30, 2010, and December 31, 2009.

	September 30, 2010			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Cash Flow Hedges				
Foreign currency	$ 1	$ -	$ 1	Other current assets
Fair Value Hedges				
Interest rate	45	-	45	Other noncurrent assets
Total Designated Hedges	46	-	46	
Not Designated as Hedges				
Commodity	173	208	(35)	Other current assets
Total Not Designated as Hedges	173	208	(35)	
Total	$ 219	$ 208	$ 11	

	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
Cash Flow Hedges				
Foreign currency	$ -	$ -	$ -	Other current liabilities
Fair Value Hedges				

Commodity	-	1	1	Other current liabilities
Total Designated Hedges	-	1	1	
Not Designated as Hedges				
Commodity	13	15	2	Other current liabilities
Total Not Designated as Hedges	13	15	2	
Total	$ 13	$ 16	$ 3	

17

Notes to Consolidated Financial Statements (Unaudited)

Derivatives Designated as Cash Flow Hedges

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

(In millions)	Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards:			
Dollar (Canada)	October 2010 - December 2010	$ 8	1.080 (a)

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

(In millions)	Period	Notional Amount	Weighted Average Exercise Price
Foreign Currency Options:			
Dollar (Canada)	October 2010 - December 2010	$ 48	1.040 (a)

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

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

	Gain (Loss) in OCI			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Foreign currency	$ 1	$ 19	$ 4	$ 37
Interest rate	-	-	-	(15)

Derivatives Designated as Fair Value Hedges

As of September 30, 2010, we had multiple interest rate swap agreements with a total notional amount of $1,450 million at a weighted-average, LIBOR-based, floating rate of 4.4 percent.

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

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2010	2009	2010	2009
Derivative					
Interest rate	Net interest and other financing costs	$ 15	$ 26	$ 39	$ (3)
Hedged Item					
Long-term debt	Net interest and other financing costs	$ (15)	$ (26)	$ (39)	$ 3

Derivatives not Designated as Hedges

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

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

Notes to Consolidated Financial Statements (Unaudited)

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

(a) Million British thermal units.

(b) Colorado Interstate Gas Co. (“CIG”).

(c) Natural Gas Pipeline Co. of America (“NGPL”).

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

	Position	Bbls per Day	Weighted Average (Dollars per Bbl)	Benchmark
Crude Oil				
Exchange-traded	Long(a)	88,641	$ 77.27	CME and IPE Crude(b) (c)
Exchange-traded	Short(a)	(128,885)	$ 77.17	CME and IPE Crude(b) (c)

	Position	Bbls per Day	Weighted Average (Dollars per Gallon)	Benchmark
Refined Products				
Exchange-traded	Long(d)	10,121	$ 2.04	CME Heating Oil and RBOB(b) (e)
Exchange-traded	Short(d)	(12,764)	$ 2.06	CME Heating Oil and RBOB(b) (e)

(a) 97 percent of these contracts expire in the fourth quarter of 2010.
(b) Chicago Mercantile Exchange (“CME”).
(c) International Petroleum Exchange (“IPE”).
(d) 100 percent of these contracts expire in the fourth quarter of 2010.
(e) Reformulated Gasoline Blendstock for Oxygen Blending (“RBOB”).

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

		Gain (Loss)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	Income Statement Location	2010	2009	2010	2009
Commodity	Sales and other operating revenues	$4	$(11)	$133	$80
Commodity	Cost of revenues	(17)	(17)	27	(59)
Commodity	Other income	1	4	3	7
		$(12)	$(24)	$163	$28

19

Notes to Consolidated Financial Statements (Unaudited)

13. Debt

At September 30, 2010, we had no borrowings against our revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

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

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

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

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

14. Stock-Based Compensation Plans

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

	Stock Options		Restricted Stock	
	Number of Shares	Weighted Average Exercise Price	Awards	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2009	18,230,074	$ 35.01	1,441,499	$ 44.89
Granted (a)	4,757,080	30.00	453,674	30.54
Options Exercised/Stock Vested	(376,995)	21.89	(522,197)	49.50
Canceled	(802,503)	39.12	(124,611)	40.71
Outstanding at September 30, 2010	21,807,656	$ 34.00	1,248,365	$ 38.16

(a) The weighted average grant date fair value of stock option awards granted was $8.70 per share.

Notes to Consolidated Financial Statements (Unaudited)

15. Stockholders' Equity

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

16. Supplemental Cash Flow Information

(In millions)	Nine Months Ended September 30, 2010	2009
Net cash provided from operating activities:		
Interest paid (net of amounts capitalized)	$ 93	$ 26
Income taxes paid to taxing authorities	1,426	1,398
Commercial paper and revolving credit arrangements, net:		
Commercial paper - issuances	$ -	$ 897
- repayments	-	(897)
Total	$ -	$ -
Noncash investing and financing activities:		
Capital lease obligations increase	$ 26	$ 73
Debt payments made by United States Steel	106	15

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.

(in millions)	Nine Months Ended September 30, 2010	2009
Additions to property, plant and equipment	$ 3,634	$ 4,749
Change in capital accruals	(293)	(402)
Discontinued operations	-	69
Capital expenditures	$ 3,341	$ 4,416

17. Commitments and Contingencies

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

Contractual commitments – At September 30, 2010, Marathon's contract commitments to acquire property, plant and equipment were $2,843 million.

21

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

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

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

Certain sections of Management's Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "shou similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in our 2009 Annual Report on Form 10-K and the update to Item 1A. Risk Factors later in this Form 10-Q.

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

Overview and Outlook

Gulf of Mexico Drilling Moratorium

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

As a result of the Deepwater Horizon incident, the U.S. Department of the Interior issued a drilling moratorium, which was lifted on October 12, 2010, to suspend the drilling of wells using subsea blowout preventers or operations using a floating facility. As a result of the drilling moratorium, we suspended drilling an exploratory well on the Innsbruck prospect, located on Mississippi Canyon Block 993. Although the drilling moratorium has been lifted, it is not known when plans and permits will be approved for future deepwater drilling activity. The effects of new or additional laws or regulations that may be adopted in response to this incident are not fully known at this time and may impact future project execution.

Exploration and Production ("E&P")

Exploration

Our 2010 exploration program is expected to exceed $1 billion and is focused on North America resource plays, the deepwater Gulf of Mexico, Indonesia, Norway and Libya. As stated above, in the Gulf of Mexico we suspended drilling on the Innsbruck prospect during the second quarter due to the drilling moratorium. The Noble Jim Day drilling rig has been contracted and is scheduled to become available in the fourth quarter of 2010, subject to regulatory uncertainties described above. Commissioning and testing of the rig has begun. It is our intent to reestablish our Gulf of Mexico exploration and development programs unless new laws, regulations or court orders prohibit these activities or make them not viable financially. The revised cost of the Innsbruck well is now estimated at $145 million. We are the operator and hold an 85 percent working interest in the prospect.

In December 2009, we began drilling an exploratory well on the Flying Dutchman prospect, located on Green Canyon Block 511 in the Gulf of Mexico. The Flying Dutchman reached its targeted total depth in early May 2010. The well encountered hydrocarbon-bearing sands that require further technical evaluation. During the second quarter of 2010, we expensed approximately $51 million for drilling costs incurred below the depth of the hydrocarbon-bearing sands and have approximately $95 million of exploratory well costs suspended as of September 30, 2010 . The results of the Flying Dutchman will continue to be evaluated along with additional potential drilling on Green Canyon Block 511 to determine overall commerciality. We are the operator and have a 63 percent working interest in this prospect.

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

We acquired approximately 120,000 net acres within the Niobrara play in the DJ Basin of southeast Wyoming and northern Colorado. We expect to commence drilling in 2011.

In the Oklahoma Woodford shale, we continue to expand our acreage position and now hold approximately 75,000 net acres within the play. We have existing production operations in this geographical area which will facilitate early drilling, with initial wells currently in progress.

In Indonesia, we began our deepwater exploration drilling program in the Pasangkayu block in August 2010 and are targeting the Bravo and Romeo prospects. The Bravo exploration well is expected to reach total depth in the fourth quarter while the Romeo exploration well is expected to reach total depth during the first half of 2011. We are the operator and hold a 70 percent working interest in the Pasangkayu block.

In October 2010, we announced the acquisition of a position in four exploration blocks in the Kurdistan Region of Iraq. We have signed production sharing agreements for operatorship and an 80 percent ownership in two open blocks northeast of Erbil, Harir and Safen. The Kurdistan Regional Government will hold a 20 percent interest but bear no costs. We were assigned working interests in two additional blocks located north-northwest of Erbil, Atrush in which we have a 20 percent working interest and Sarsang in which we have a 25 percent working interest. The total entry cost, subject to final adjustments, is $156 million plus a pro rata share of historic exploration costs estimated to be $20 million. This transaction provides us with access to approximately 295,000 net acres. We have committed to a seismic program and to drilling one well on each of the two open blocks during the initial three-year exploration period. The Atrush and Sarsang blocks each have a well currently drilling.

In September 2010, we added an eleventh license with shale gas potential in Poland, increasing our total acreage position to approximately 2.3 million net acres. We have a 100 percent interest and operate all 11 blocks. We continue to pursue additional licenses and plan to begin geologic studies in Poland in 2010 followed by the acquisition of seismic in 2011 and plans to initiate drilling by the fourth quarter of 2011.

Production

Net liquid hydrocarbon and natural gas sales averaged 399 thousand barrels of oil equivalent per day ("mboepd") during the third quarter and 382 mboepd during the first nine months of 2010 compared to 366 and 396 mboepd during the third quarter and first nine months of 2009. The increase in sales volumes in the third quarter of 2010 over the same period of the previous year is primarily related to Droshky development production beginning in this quarter and reliability at both our Alvheim development offshore Norway and the Alba field and related facilities in Equatorial Guinea. The 3 percent decrease for the nine-month period was primarily related to the sale of a portion of our Permian Basin assets in the second quarter of 2009, the planned turnaround in Equatorial Guinea in the first four months of 2010, maintenance downtime offshore U.K., and normal production declines.

Our Droshky development in the Gulf of Mexico on Green Canyon Block 244 began production in mid-July of 2010 and reached peak net production of 45,000 boepd in the third quarter of 2010, down from the original estimate of 50,000 boepd. Production declines have been steeper than anticipated due to reservoir compartmentalization and lack of aquifer support. This subsea project consists of four development wells tied back to a third-party platform. Three of the four wells are currently producing, while production from the fourth well has been delayed due to an equipment issue. We plan to re-enter the fourth well in the first quarter of 2011 to make the necessary repairs. We hold a 100 percent operated working interest and an 81 percent net revenue interest in Droshky.

Our net liquid hydrocarbon sales in North Dakota from the Bakken Shale resource play have increased to 13 thousand barrels per day (“bpd”) in third quarter of 2010 compared to 11 mbpd in the same quarter of last year. We added a sixth operated rig during the third quarter of 2010.

In the second quarter of 2010, we commenced production at the Volund field offshore Norway which allows us to maintain full capacity on the Alvheim floating production, storage and offloading (“FPSO”) vessel. We hold a 65 percent operated interest in the Volund field.

In Libya, Phase II of the Faregh project began commissioning during the third quarter of 2010 and first production is expected in November 2010. We have continued our exploration program in Libya with six discoveries 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, exploration budget, anticipated future exploratory and development drilling activity, the Droshky development, the possibility of a significant new resource base in the Iraqi Kurdistan region, Phase II of the Faregh project in Libya, and the drilling moratorium. While the drilling moratorium was lifted on October 12, 2010, we cannot predict when plans and permits will be approved for future deepwater drilling activities. Some factors that could potentially affect these forward-looking statements include pricing, supply and demand for crude oil, natural gas and petroleum products, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements. The exploration budget is based on current expectations, estimates and projections and is not a guarantee of future performance. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits.

Oil Sands Mining (“OSM”)

Our net synthetic crude oil sales were 31 thousand barrels per day (“mbpd”) in the third quarter and 25 mbpd in the first nine months of 2010 compared to 33 mbpd and 31 mbpd in same periods of 2009. Current year sales continue to reflect the impact of the planned turnaround at the Muskeg River mine and upgrader that began March 22, 2010 and halted production in April before a staged resumption of operations in May. Incurred in the first six months of 2010, our net share of total turnaround costs was $99 million.

In the third quarter of 2010, the AOSP Expansion 1 project began a phased start-up of the Jackpine Mine operations, which will add capacity of 100,000 gross bpd to the existing Muskeg River Mine capacity of 155,000 bpd. The expanded upgrader operations are on schedule for a phased start-up beginning in late 2010 and extending into early 2011. Expansion 1 includes construction of mining and extraction facilities at the Jackpine mine, expansion of treatment facilities at the existing Muskeg River mine, expansion of the Scotford upgrader and development of related infrastructure. We hold a 20 percent working interest in the AOSP.

The above discussion includes forward-looking statements with respect to the start of operations of AOSP Expansion 1. Factors that could affect the project are transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, delays in obtaining or conditions imposed by necessary government and third-party approvals and other risks customarily associated with construction projects.

Integrated Gas (“IG”)

Our share of LNG sales worldwide totaled 7,142 metric tonnes per day (“mtpd”) for the third quarter of 2010 compared to 6,372 mtpd in the third quarter of 2009 and 6,502 mtpd in the first nine months of 2010 compared to 6,583 mtpd in the first nine months of 2009. These LNG sales volumes include both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska are conducted through a consolidated subsidiary. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

Refining, Marketing and Transportation (“RM&T”)

Our total refinery throughputs were 21 percent higher in the third quarter and 15 percent higher in the first nine months of 2010 compared to the same periods of 2009. Crude oil refined increased 24 percent in both periods primarily related to the startup of the Garyville, Louisiana, expansion, while other charge and blendstocks increased 6 percent and decreased 25 percent compared to the third quarter and first nine months of 2009. Due to the significant turnaround activity in the first quarter of 2010, along with the expected reduction in external charge and blendstocks requirements due to the Garyville refinery expansion, we have reduced our purchased charge and blendstocks volume in the first nine months of 2010.

We completed turnarounds at our Garyville, Texas City, Texas, Catlettsburg, Kentucky, Robinson, Illinois and St. Paul Park, Minnesota, refineries in the first nine months of 2010. Such activity compares to turnarounds at our Canton, Ohio; Robinson, Catlettsburg and Garyville refineries in the first nine months of 2009.

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

Ethanol volumes sold in blended gasoline increased to an average of 72 mbpd for the third quarter and 67 mbpd in the first nine months of 2010 compared to 62 mbpd and 59 mbpd in the same periods of 2009. The future expansion or contraction of our ethanol blending program will be driven by the economics of ethanol supply and government regulations.

Third quarter 2010 Speedway SuperAmerica LLC (“SSA”) same store gasoline sales volume increased 6 percent when compared to the third quarter of 2009, while same store merchandise sales increased by 3 percent for the same period. During the first quarter of 2010, Speedway was ranked the nation’s top retail gasoline brand for the second consecutive year, according to the 2010 EquiTrend® Brand Study conducted by Harris Interactive®.

As of September 30, 2010, the heavy oil upgrading and expansion project at our Detroit, Michigan, refinery was approximately 47 percent complete and on schedule for an expected completion in the second half of 2012.

In October 2010, we entered into definitive agreements to sell our St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 Speedway SuperAmerica retail outlets, plus related inventories. The fair value of the consideration is estimated to be approximately $900 million, which includes the estimated value of inventory and the fair values of (1) a retained preferred stock interest in the buyer with a stated value of $80 million, (2) a maximum $125 million earnout provision payable to us over eight years, and (3) a maximum $60 million of margin support payable to the buyer over two years. Cash proceeds at closing are estimated to be $700 million. The earnout and margin support provisions in the agreements are subject to certain conditions and any margin support paid may be recovered by an increase in the total earnout amount. We expect the sale transaction to close by yearend 2010, contingent upon the buyer meeting the conditions of their financing arrangements and other customary closing conditions.

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

Market Conditions

Exploration and Production

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices have been volatile in recent years, but both West Texas Intermediate crude oil and Dated Brent crude oil monthly average prices have been in the $75 to $85 per barrel range during 2010. The following table lists benchmark crude oil and natural gas price averages in the third quarter and first nine months of 2010, when compared to the same periods in 2009.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2010	2009	2010	2009
West Texas Intermediate ("WTI") crude oil (Dollars per barrel)	$ 76.21	$ 68.24	$ 77.69	$ 57.32
Dated Brent crude oil (Dollars per barrel)	$ 76.86	$ 68.08	$ 77.14	$ 57.32
Henry Hub natural gas (Dollars per mmbtu)(a)	$ 4.38	$ 3.39	$ 4.59	$ 3.93

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

Our domestic crude oil production is 60 to 70 percent sour, which means that it contains more sulfur than light sweet WTI does. Sour crude oil also tends to be heavier than and sells at a discount to light sweet crude oil because of its higher refining costs and lower refined product values. Our international crude oil production is relatively sweet and is generally sold in relation to the Dated Brent crude oil benchmark.

A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas. Our other major natural gas-producing region is Equatorial Guinea, where large portions of our natural gas sales is subject to term contracts, making realized prices in this area less volatile. As we sell larger quantities of natural gas from these regions, since these fixed prices are generally lower than prevailing prices, our reported average natural gas prices realizations may not track market price movements.

Oil Sands Mining

OSM segment revenues correlate with prevailing market prices for the various qualities of synthetic crude oil and vacuum gas oil we produce. Roughly two-thirds of our normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil market, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mine or upgrader. See Note 12 for the commodity derivatives contracts related to 2010 forecasted sales.

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

The table below shows benchmark prices that impacted both our revenues and variable costs for the third quarter and first nine months of 2010 and 2009:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Benchmark	2010	2009	2010	2009
WTI crude oil (Dollars per barrel)	$ 76.21	$ 68.24	$ 77.69	$ 57.32
Western Canadian Select (Dollars per barrel)(a)	$ 60.55	$ 58.12	$ 64.72	$ 48.15
AECO natural gas sales index (Canadian dollars per gigajoule)(b)	3.36	2.78	3.93	3.59

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.
(b) Monthly average of Alberta Energy Company ("AECO") day ahead index.

Integrated Gas

Our integrated gas operations include marketing and transportation of products manufactured from natural gas, such as LNG and methanol, primarily in the U.S., Europe and West Africa.

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. Light Louisiana Sweet ("LLS") prices and a 6-3-2-1 ratio of products (6 barrels of crude oil refined into 3 barrels of gasoline, 2 barrels of distillate and 1 barrel of residual fuel) are used for the crack spread calculation.

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

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars per barrel)	2010	2009	2010	2009
Chicago LLS 6-3-2-1 crack spread	$ 3.68	$ 3.93	$ 3.40	$ 4.20
U.S. Gulf Coast LLS 6-3-2-1 crack spread	$ 1.70	$ 2.50	$ 2.49	$ 2.99
Sweet/Sour differential(a)	$ 8.08	$ 5.64	$ 7.39	$ 5.62

(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 LLS.

Even though the LLS 6-3-2-1 crack spread was lower in the third quarter of 2010 compared to the same period of 2009, our realized margin for the period improved from processing sour crude, due to the widening of the sweet/sour differential. The benchmark sweet/sour differential widened 43 percent in the third quarter and 31 percent in the first nine months of 2010 relative to the same periods of last year. Due to the Garyville refinery expansion we were able to process a higher volume of sour crude oil during the third quarter and the first nine months of 2010. Within our refining system, sour crude accounted for 51 percent of the 1,263 mbpd of crude oil processed in the third quarter of 2010 and 53 percent of the 1,166 mbpd of crude oil processed in the first nine months of 2010 compared to 49 percent of the 1,019 mbpd of crude processed in the third quarter and 52 percent of the 943 mbpd of crude processed in the first nine months in 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.

Results of Operations

Consolidated Results of Operation

Consolidated net income for 2010 was 69 percent higher in third quarter and 68 percent higher in the first nine months than in the same periods of 2009. Higher liquid hydrocarbon realizations and sales volumes in the third quarter of 2010 compared to the same period of 2009 increased E&P segment income, while RM&T segment income was increased as a result of improved refining and marketing gross margins combined with higher increased throughput. The income increase in the first nine months of 2010 was primarily related to higher liquid hydrocarbon realizations.

Revenues are summarized by segment in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
E&P	$ 2,532	$ 1,979	$ 7,683	$ 5,386
OSM	190	167	534	444
IG	38	15	98	33
RM&T	15,897	12,407	45,054	32,148

Segment revenues		18,657		14,568		53,369		38,011
Elimination of intersegment revenues		(214)		(193)		(608)		(506)
Gain (Loss) on U.K. natural gas contracts		-		(13)		-		72
Total revenues	$	18,443	$	14,362	$	52,761	$	37,577
Items included in both revenues and costs:								
Consumer excise taxes on petroleum products and merchandise	$	1,351	$	1,258	$	3,871	$	3,658

E&P segment revenues increased $553 million in the third quarter and $2,297 million in the first nine months of 2010 from the comparable prior-year periods. The increases were primarily a result of higher liquid hydrocarbon and natural gas price realizations. Liquid hydrocarbon realizations averaged $72.95 per barrel in the third quarter and

$73.64 in the first nine months of 2010 compared to $64.12 and $53.62 in the same periods of 2009, while natural gas realizations averaged $2.69 per mcf in the third quarter and $2.86 in the first nine months of 2010 compared to $2.20 and $2.42 in the same periods of 2009.

Revenues in both 2010 periods include the impact of derivative instruments intended to mitigate price risk on future sales of liquid hydrocarbons and natural gas. A net pretax gain of $13 million was reported by the E&P segment in the third quarter of 2010, while there was a net pretax gain of $91 million in the first nine months of 2010.

For the third quarter and the first nine months of 2009, losses of $13 million and gains of $72 million related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments were excluded for E&P segment revenues. Those contracts expired in the third quarter of 2009.

Net sales volumes from continuing operations during the quarter were 399 mboepd in 2010 and 366 mboepd in 2009. Net sales volumes for the first nine months of 2010 were 3 percent lower than the comparable prior-year period, primarily impacted by the sale of a portion of our Permian Basin assets in the second quarter of 2009, the planned turnaround in Equatorial Guinea during the first four months of 2010, maintenance downtime offshore U.K., and normal production declines. This decrease in sales volumes partially offsets the impact of the liquid hydrocarbon and natural gas realization increases previously discussed.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
E&P Operating Statistics				
Net Liquid Hydrocarbon Sales (mbpd)				
United States	80	63	65	64
Europe	80	76	92	87
Africa	89	83	84	87
Total International	169	159	176	174
Worldwide Continuing Operations	249	222	241	238
Discontinued Operations(a)	-	10	-	6
Worldwide	249	232	241	244
Natural Gas Sales (mmcfd)				
United States	363	339	350	376
Europe(b)	99	119	104	143
Africa	442	409	399	427
Total International	541	528	503	570
Worldwide Continuing Operations	904	867	853	946
Discontinued Operations(a)	-	-	-	22
Worldwide	904	867	853	968
Total Worldwide Sales (mboepd)				
Continuing Operations	399	366	382	396
Discontinued Operations(a)	-	10	-	9
Worldwide	399	376	382	405

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
E&P Operating Statistics				
Average Realizations (c)				
Liquid Hydrocarbons (per bbl)				
United States	$ 69.52			