Dear Fellow Stockholders,

As the global economy began its recovery, resulting in stronger demand, prices and margins for our products, Marathon was well positioned to benefit as a result of our significant investment program over the past few years. Our net income of $2.6 billion in 2010 was 76 percent higher than in 2009. We also realized a more than 10 percent increase in net cash provided by operating activities, which allowed us to invest for the future, reduce our debt and increase our quarterly dividend. We increased the quarterly dividend 4 percent in 2010, the sixth time over the past eight years.

The Garyville Major Expansion, the largest single construction project ever undertaken by Marathon, reached full operational capacity in first quarter 2010 and performed well throughout the year, adding more than 200,000 barrels per day (bpd) of crude oil refining capacity and substantially increasing profitability.

In the Oil Sands Mining segment, we saw the start of operations at the Athabasca Oil Sands Mining (AOSP) expansion. The production from the new Jackpine Mine was offset by a major turnaround at the base Muskeg River Mine completed in 2010. Moving forward, the combined capacity of this operation is expected to deliver significant earnings and cash flow for decades to come. We plan for the AOSP Expansion 1 to reach full production by mid-year 2011.

Total crude oil and natural gas sales from the Exploration and Production (E&P) segment in 2010 were slightly lower than in 2009. Increased operational reliability, particularly in Norway and Equatorial Guinea (EG), largely offset the disappointing results of our U.S. Gulf of Mexico Droshky development.

As part of our ongoing evaluation of our businesses, we continued to optimize our asset base during 2010. We completed the sale of a 20 percent interest in Angola Block 32 for $1.3 billion, closed the sale of our St. Paul Park refinery and associated assets for a transaction value of $935 million and announced the sale of our interest in the Gudrun project in Norway.

Increased focus on liquids

Through strategic investments, we increased our opportunity set in unconventional, liquids-rich U.S. resource plays by 60 percent during 2010. Including our Canadian in-situ assets, we now hold more than 780,000 net acres across North America in liquids-rich resource plays.

In our impact exploration program, we acquired four blocks in the Iraqi Kurdistan Region. We have a working interest in two exploration wells in this highly prolific region, and both have discovered oil, with further testing ongoing. Additionally, we increased our shale position in Poland to 2.3 million net acres across 11 blocks. While our position in Poland is targeting natural gas, the higher and more stable prices in Europe make this an attractive area.

Largely because of low U.S. natural gas prices, we reduced our current drilling for gas, which led to an overall reserve replacement of 75 percent. However, because of our focus on liquids, we replaced 109 percent of liquid hydrocarbon production.

Lowering feedstock costs in Refining, Marketing and Transportation

We continue to focus on value accretive investments such as the $2.2 billion Detroit Heavy Oil Upgrade Project (DHOUP). Designed to capitalize on the growing Canadian oil sands production and lower feedstock costs, this project is on schedule for completion in the second half of 2012.

Marathon's offshore well control capabilities

Following the Deepwater Horizon tragedy, Marathon thoroughly assessed our capacity to manage a catastrophic offshore event. We studied published reports of the incident and developed recommendations for maintaining control of fluids, secondary and emergency control systems, responsibility and accountability.

To reinforce our safety culture, we issued the Marathon Health, Environmental and Safety Beliefs, highlighting our expectation that workers will communicate openly, honestly and often about safety. We stressed not only their right but their obligation to stop work if they have safety concerns.

We believe that our Company and the industry are targeting the right issues to address offshore safety responsibly and effectively so that we can continue meeting our customers' energy needs.

Creating two highly focused, independent energy companies

As noted earlier, we have invested heavily over the past few years. We've done so to improve our competitiveness and increase value. Given the largest part of this investment is behind us, along with improving global financial conditions and the strength of both businesses, the Board of Directors announced in January plans to spin off our downstream assets as Marathon Petroleum Corporation (MPC), creating two independent, highly focused energy companies. Our priorities are to ensure both companies have strong balance sheets and significant financial flexibility at the expected effective date of June 30, 2011.

MPC is expected to be the fifth largest U.S. refiner, with geographically and strategically aligned operations across the downstream value chain. MPC's operations will include a six-plant refining network with 1,142,000 bpd of crude oil refining capacity, an extensive terminal and transportation system and significant marketing operations concentrated in the Midwest, Gulf Coast and Southeast regions of the U.S.

Marathon Oil Corporation (MRO) will focus on its liquids-rich E&P and Oil Sands Mining segments with upside from Integrated Gas. MRO has a solid asset portfolio, including world-class liquids and natural gas processing facilities in EG, major liquid hydrocarbon operations in Norway, oil and natural gas production in key U.S. energy basins, an interest in Canada's AOSP, and impact exploration positions in multiple basins.

Our employees have built what will be two investment grade companies, each with sufficient liquidity and financial flexibility to pursue their own strategic objectives. The spin-off and resulting formation of two strong, independent companies marks another chapter in our Company's proud 124-year history. As it has been throughout our history, our success is largely a result of Marathon's employees. We are especially grateful to our more than 29,000 employees and their ongoing commitment to superior results for investors, business partners, suppliers, communities and other stakeholders.

Respectfully,

Thomas J. Usher
Chairman

C.P. Cazalot Jr.

Clarence P. Cazalot Jr.
President and Chief Executive Officer

This annual report marks a shift in the way we communicate financial performance to stakeholders. While the printed report is streamlined, we plan to provide in-depth information on www.marathon.com that we hope will deepen your understanding of our operations, values, strengths and future outlook.

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2010

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)

Securities registered pursuant to Section 12(b) of the Act

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2010: $22,006 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 710,280,842 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2011.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2011 annual meeting of stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

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

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "could," "may," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Report may include, but are not limited to, levels of revenues, gross margins, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production, sales, throughput or shipments of liquid hydrocarbons, natural gas, synthetic crude oil and refined products; levels of worldwide prices of liquid hydrocarbons, natural gas and refined products; levels of reserves of liquid hydrocarbons, natural gas and synthetic crude oil; the acquisition or divestiture of assets; the effect of restructuring or reorganization of business components; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local regulatory authorities.

PART I

Item 1. Business

Plan to Create Independent Downstream Company

On January 13, 2011, the Board of Directors of Marathon Oil Corporation ("Marathon") announced that it has approved moving forward with plans to spin off our downstream (Refining, Marketing and Transportation) business, creating two independent energy companies: Marathon Petroleum Corporation ("MPC") and Marathon Oil Corporation ("MRO"). To effect the spin-off, we intend to distribute one common share of MPC for every two common shares of Marathon held at a record date to be determined. The transaction is expected to be effective June 30, 2011, with distribution of MPC shares shortly thereafter. A tax ruling request was submitted to the U.S. Internal Revenue Service ("IRS") regarding the tax-free nature of the spin-off and we anticipate a response during the second quarter of 2011.

The above discussion of the plans to create an independent downstream company includes forward looking statements. Factors which could affect the plans include board approval, receipt of a favorable private letter ruling from the IRS and a registration statement declared effective by the Securities and Exchange Commission ("SEC").

General

Marathon Oil Corporation was originally organized in 2001 as USX HoldCo, Inc., a wholly-owned subsidiary of the former USX Corporation. As a result of a reorganization completed in July 2001, USX HoldCo, Inc. (1) became the parent entity of the consolidated enterprise (the former USX Corporation was merged into a subsidiary of USX HoldCo, Inc.) and (2) changed its name to USX Corporation. In connection with the transaction described in the next paragraph (the "USX Separation"), USX Corporation changed its name to Marathon Oil Corporation.

Before December 31, 2001, Marathon had two outstanding classes of common stock: USX-Marathon Group common stock, which was intended to reflect the performance of our energy business, and USX-U.S. Steel Group common stock ("Steel Stock"), which was intended to reflect the performance of our steel business. On December 31, 2001, we disposed of our steel business through a tax-free distribution of the common stock of our wholly-owned subsidiary United States Steel Corporation ("United States Steel") to holders of Steel Stock in exchange for all outstanding shares of Steel Stock on a one-for-one basis.

In connection with the USX Separation, our certificate of incorporation was amended on December 31, 2001, and Marathon has had only one class of common stock authorized since that date.

Segment and Geographic Information

Our operations consist of four reportable operating segments: 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; 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, transports and markets crude oil and petroleum products, primarily in the Midwest, Gulf Coast and southeastern regions of the United States. For operating segment and geographic financial information, see Note 8 to the consolidated financial statements.

The E&P, OSM and IG segments comprise our upstream operations. The RM&T segment comprises our downstream operations.

Exploration and Production

In the discussion that follows regarding our exploration and production operations, references to "net" wells, sales or investment indicate our ownership interest or share, as the context requires.

At the end of 2010, we were conducting oil and gas exploration, development or production activities in ten countries: the United States, Angola, Canada, Equatorial Guinea, Indonesia, Libya, Norway, Poland, the Iraqi Kurdistan Region, and the United Kingdom.

Our 2010 worldwide net liquid hydrocarbon sales averaged 245 thousand barrels per day ("mbpd"). Our 2010 worldwide net natural gas sales, including natural gas acquired for injection and subsequent resale, averaged 878 million cubic feet per day ("mmcfd"). In total, our 2010 worldwide net sales averaged 391 thousand barrels of oil equivalent per day ("mboepd"). For purposes of determining barrels of oil equivalent ("boe"), natural gas volumes are converted to approximate liquid hydrocarbon barrels by dividing the natural gas volumes expressed in thousands of cubic feet ("mcf") by six. The liquid hydrocarbon volume is added to the barrel equivalent of natural gas volume to obtain boe.

In the United States during 2010, we drilled 77 gross (36 net) exploratory wells of which 73 gross (32 net) wells encountered commercial quantities of hydrocarbons. Of these 73 wells, 35 were temporarily suspended or in the process of being completed at year end. Internationally, we drilled 10 gross (2 net) exploratory wells of which 7 gross (1 net) wells encountered commercial quantities of hydrocarbons. All 7 wells were temporarily suspended or were in the process of being completed at December 31, 2010.

North America

United States – Our U.S. operations accounted for 29 percent of our 2010 worldwide net liquid hydrocarbon sales volumes and 41 percent of our worldwide net natural gas sales volumes.

Offshore – The Gulf of Mexico continues to be a core area, with over 20 prospects. At year end 2010, we held material interests in seven producing fields, four of which are company operated. An eighth field is under development and anticipated to come on-line in 2011.

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. Marathon had no involvement in the incident.

As a result of the Deepwater Horizon incident, the U.S. Department of the Interior issued a drilling moratorium on May 30, 2010, to suspend the drilling of deepwater wells, and prohibit drilling any new deepwater wells (defined as greater than 500 foot water depth). Shortly after the moratorium was issued, we temporarily suspended drilling an exploratory well on the Innsbruck prospect, located on Mississippi Canyon Block 993. Although the drilling moratorium was lifted on October 12, 2010, it is not known when plans and permits will be approved for future deepwater drilling activity. We sent a Revised Development Operations Coordination Document for the Ozona completion and a Revised Exploration Plan for the Innsbruck well to the Bureau of Ocean Energy Management Regulation and Enforcement ("BOEMRE"). We continue to update our revised Oil Spill Response Plan as new and updated requirements come from the BOEMRE. We filed our first deepwater Exploration Plan since the Deepwater Horizon incident to the BOEMRE on October 15, 2010. We are continuing to engage the BOEMRE to provide them with all the requested information. The BOEMRE has not yet deemed our plan submitted. 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.

We operate the Ewing Bank 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform started operations in 1994 and serves as a production hub for the Ewing Bank 873 (Lobster), Ewing Bank 917 (Oyster) and Ewing Bank 963 (Arnold) fields. The facility also processes third-party production via subsea tie-backs.

We own a 50 percent interest in the outside-operated Petronius field on Viosca Knoll Blocks 786 and 830. The Petronius platform is capable of providing processing and transportation services to nearby third-party fields.

The Neptune development commenced production of liquid hydrocarbons and natural gas in July 2008. We hold a 30 percent working interest in this outside-operated development located on Atwater Valley 575, 120 miles off the coast of Louisiana. The completed Phase I development included six subsea wells tied back to a stand-alone platform. Phase II development activities have begun and the first well in this program was successfully drilled and completed in late 2009.

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. 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. We plan to re-enter the fourth well in the first quarter of 2011. We hold a 100 percent operated working interest and an 81 percent net revenue interest in Droshky.

Development of our operated Ozona prospect, located on Garden Banks Block 515, has also continued. We are in the process of securing a rig to complete the previously drilled appraisal well and tie back to the nearby third-party Auger platform. First production of liquid hydrocarbon is expected in 2011. We hold a 68 percent working interest in Ozona.

In 2008, we drilled a successful oil appraisal well on the Stones prospect located on Walker Ridge Block 508. We hold a 25 percent interest in the outside-operated Stones prospect. In the third quarter of 2008, we announced deepwater oil discovery on the Gunflint prospect located on Mississippi Canyon Block 948. We own a 13 percent interest in this outside-operated prospect. In the first quarter of 2009, we participated in a deepwater oil discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 10 percent interest in the outside-operated 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. We have 63 percent ownership and are the operator of this liquid hydrocarbon prospect. The Flying Dutchman reached its targeted total depth in early May 2010. The well encountered hydrocarbon-bearing sands that require further technical evaluation. The results of the Flying Dutchman well will continue to be evaluated to determine overall commerciality.

In addition to the prospects listed above, we held interests in 103 blocks in the Gulf of Mexico at the end of 2010, including 97 in the deepwater area. Our plans call for exploration drilling on some of these leases in 2011 and 2012, presuming a favorable regulatory environment that will allow deep-water drilling to resume.

Onshore – We hold 391,000 net acres in the Bakken shale oil play in the Williston Basin of North Dakota with a working interest of approximately 80 percent. Approximately 275 company-operated locations will be drilled over the next 4 years. We are evaluating other potential horizons above and below the Middle Bakken. We currently have six operated drilling rigs running in our Bakken shale program, and will add a rig solely dedicated to completion operations in the first quarter of 2011.

In the Anadarko Woodford shale horizon, a liquids-rich play in Oklahoma, we continue to expand our acreage position and now hold approximately 88,000 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. We plan to increase from three to eight company operated rigs in 2011. We also have domestic natural gas operations in Oklahoma, East Texas, and North Louisiana with combined net gas sales of 103 mmcfd in 2010.

In December 2010, we entered into an agreement with an operator in the Eagle Ford shale, a liquids-rich play in Texas. We initially paid $10 million and will drill and complete four wells to earn approximately 17,000 net acres. We also have an option that expires October 31, 2011 to purchase the operator's remaining 58,000 net acres at a total cost of approximately $209 million, including the initial payment, carried well interest and lease extensions. In the event that we do not exercise the purchase option, the operator has the option to put the remaining 58,000 acres to us at a total cost, including the initial payment, carried well interest and lease extensions, of approximately $92 million.

We hold leases with natural gas production in the Piceance Basin of Colorado, located in Garfield County in the Greater Grand Valley field complex. We acquired approximately 177,000 net acres within the Niobrara play in the DJ Basin of northern Colorado and southeast Wyoming. We expect to commence drilling in 2011 and will leverage our Bakken operating experience. Net liquid hydrocarbon and natural gas sales from our existing Wyoming fields averaged 24 mbpd and 106 mmcfd in 2010. We plan to drill approximately 20 company operated wells in 2011 in the Big Horn, Wind River and Powder River Basins.

We hold acreage in two additional emerging shale resource plays in the U.S. In the Appalachian Basin we hold 80,000 net acres in the Marcellus shale natural gas play in Pennsylvania and West Virginia. In February 2011, we entered into a joint venture with a company on a large portion of our Marcellus shale acreage position. Under the agreement terms, the company will to earn 50 percent of approximately 60,000 acres under a drilling carry. The company also has an option to acquire our remaining acreage while we retain the rights to continue to market the acreage to others. We drilled three wells in 2010 and five in 2009. In Louisiana and east Texas, we hold 20,000 net acres in the Haynesville shale natural gas play, where we drilled two wells in 2010 and one in 2009.

We produce natural gas in the Cook Inlet and adjacent Kenai Peninsula of Alaska. We have operated and outside-operated interests in ten fields and hold a 51 to 100 percent working interest in each. Typically, our natural gas sales from Alaska are seasonal in nature, trending down during the second and third quarters of each year and increasing during the fourth and first quarters. To manage supplies to meet contractual demand we produce and store natural gas in a partially depleted reservoir in the Kenai natural gas field. In 2010, we drilled three operated wells in Alaska and plan to drill one to three company-operated wells per year during 2011 and 2012.

Canada – We hold interests in both operated and outside-operated exploration stage in-situ oil sand leases as a result of the acquisition of Western in 2007. The three potential in-situ developments are Namur, in which we hold a 60 percent operated interest, Birchwood, in which we hold a 100 percent operated interest, and Ells River, in which we hold a 20 percent outside-operated interest. Initial test drilling on the Birchwood prospect confirmed bitumen presence and an additional 70 test wells are planned in 2011 to assess reservoir quality. Sanction of the initial phase of the Birchwood development is anticipated in 2014, with resulting first production expected in 2016.

Africa

Equatorial Guinea – We own a 63 percent operated working interest in the Alba field which is offshore Equatorial Guinea. During 2010, Equatorial Guinea net liquid hydrocarbon sales were 15 percent of our worldwide net liquid hydrocarbon sales volumes, and net natural gas sales were 46 percent of our worldwide net natural gas sales.

We also own a 52 percent interest in Alba Plant LLC, an equity method investee that operates an onshore liquefied petroleum gas ("LPG") processing plant. Alba field natural gas is processed by the LPG plant under a long-term contract at a fixed price for the British thermal units used in the operations of the LPG plant and for the hydrocarbons extracted from the natural gas stream in the form of secondary condensate and LPG. During 2010, a gross 753 mmcfd of natural gas was supplied to the LPG production facility and the resulting net liquid hydrocarbon sales volumes in 2010 included 3 mbpd of secondary condensate and 11 mbpd of LPG produced by Alba Plant LLC.

As part of our Integrated Gas segment, we own 45 percent of Atlantic Methanol Production Company LLC ("AMPCO") and 60 percent of Equatorial Guinea LNG Holdings Limited ("EGHoldings"), both of which are accounted for as equity method investments. AMPCO operates a methanol plant and EGHoldings operates an LNG production facility, both located on Bioko Island. Dry natural gas from the Alba field, which remains after the condensate and LPG are removed, is supplied to both of these facilities under long-term contracts at fixed prices. Because of the location of and limited local demand for natural gas in Equatorial Guinea, we consider the prices under the contracts with Alba Plant LLC, AMPCO and EGHoldings to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Our share of the income ultimately generated by the subsequent export of secondary condensate and LPG produced by Alba Plant LLC is reflected in our E&P segment. Our share of the income ultimately generated by the subsequent export of methanol produced by AMPCO and LNG produced by EGHoldings is reflected in our Integrated Gas segment as discussed below. During 2010, a gross 108 mmcfd of dry natural gas was supplied to the methanol plant and a gross 623 mmcfd of dry gas was supplied to the LNG production facility. Any remaining dry gas is returned offshore and reinjected into the Alba field for later production.

We hold a 63 percent operated interest in the Deep Luba discovery on the Alba Block and we are the operator with a 90 percent interest in the Corona well on Block D. These wells are part of our long-term LNG strategy. We expect these discoveries to be developed when the natural gas supply from the nearby Alba field starts to decline.

Angola – Offshore Angola, we hold 10 percent interests in Block 31 and Block 32, both of which are outside-operated. The discoveries on Blocks 31 and 32 represent four potential development hubs. The Plutao, Saturno, Venus and Marte discoveries and one successful appraisal well form a planned development area in the northeastern portion of Block 31. In 2008, we received approval to proceed with this first deepwater development project, called the PSVM development. The PSVM development will utilize a floating, production, storage and offloading ("FPSO") vessel. A total of 48 production and injection wells are planned with development drilling currently underway. First production is anticipated in 2012. Other discoveries on Block 31 comprise potential development areas in the southeast and middle portions of the block. A development area in the south eastern portion of Block 32 is currently being evaluated with the potential to include 6 fields for an anticipated first oil production in 2016.

Libya – We hold a 16 percent interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin. Our exploration program in 2010 included the drilling of 10 wells, including 2 carry over wells from 2009: seven of these wells were discoveries, two were dry and abandoned, and one was drilling as of yearend. We drilled 28 development wells in Libya in 2010. Phase II of the Faregh project began commissioning during the third quarter of 2010, with production coming on line in November.

Europe

Norway – Norway continues to be a core area, which complements our long-standing operations in the U.K. sector of the North Sea discussed below. We were approved for our first operatorship on the offshore Norwegian continental shelf in 2002, where today we operate ten licenses and hold interests in over 240,000 net acres.

The operated Alvheim complex located on the Norwegian continental shelf commenced production in June 2008. The complex consists of a Floating Production, Storage and Offloading ("FPSO") vessel with subsea infrastructure. Improved reliability, combined with optimization work, increased the throughput of the FPSO to 142 mbpd, up from the original design of 120 mbpd. Produced oil is transported by shuttle tanker and produced natural gas is transported to the existing U.K. Scottish Area Gas Evacuation ("SAGE") system using a 14-inch diameter, 24-mile cross border pipeline. First production to the complex was from the Alvheim development which is comprised of the Kameleon, East Kameleon and Kneler fields, in which we have a 65 percent working interest, and the Boa field, in which we have a 58 percent working interest. At the end of 2010, the Alvheim development included 11 producing wells and 2 water disposal wells. A Phase 2 drilling program commenced in 2010, with 1 well on production since December 2010 and a further two production wells to be drilled in 2011. A Phase 2b drilling program consisting of 2 production wells is planned for 2011 and 2012.

The nearby outside-operated Vilje field, in which we own a 47 percent working interest, began producing through the Alvheim complex in August 2008.

In June 2009, we completed the drilling program for the Volund field as a subsea tieback to the Alvheim complex. The Volund development, in which we own a 65 percent operated interest, is located approximately five miles south of the Alvheim area and consists of three production wells and one water injection well. First production from Volund was announced in September 2009. In the second quarter of 2010, we commenced production at the Volund field which allows us to maintain full capacity on the Alvheim FPSO. Net sales from Alvheim, Vilje, and Volund for 2010 averaged 50 mbpd of liquid hydrocarbons and 30 mmcfd of natural gas.

Also offshore Norway, we and our partners announced the Marihone and Viper discoveries, both located within tie-back distance of the Alvheim FPSO. The Marihone oil discovery is located in license PL340 about 12 miles south of the Volund and Alvheim fields. We hold a 65 percent operated working interest in Marihone. The Viper oil discovery is located immediately next to Volund field in PL203, about 12 miles south of the Alvheim FPSO. We are the operator and hold a 65 percent interest in Viper. Conceptual development studies for both discoveries have begun. First production for both discoveries is anticipated in 2014.

In December 2010 a sales agreement was entered into for all of our interests in production licenses PL 025, PL 048E and PL 187. The transaction includes our outside-operated 20 percent interest in PL 025 (Gudrun field development) and PL 187 (Brynhild discovery), and 12.5 percent interest in PL 048E (Eirin discovery).

United Kingdom – Our largest asset in the U.K. sector of the North Sea is the Brae area complex where we are the operator and have a 42 percent working interest in the South, Central, North and West Brae fields and a 38 percent working interest in the East Brae field. The Brae A platform and facilities host the underlying South Brae field and the adjacent Central and West Brae fields. A two well development program commenced in 2010 for West Brae with one well on production in January 2011, and the second expected to produce by the end of March 2011. The North Brae field, which is produced via the Brae B platform, and the East Brae field, which is produced via the East Brae platform, are natural gas condensate fields. The East Brae platform hosts the nearby Braemar field in which we have a 28 percent working interest.

The strategic location of the Brae platforms along with pipeline and onshore infrastructure has generated third-party processing and transportation business since 1986. Currently, the operators of 30 third-party fields have contracted to use the Brae system. Most recently, in 2010, we agreed to commence construction and installation of a new module to accommodate the tie back of the third-party operated Devenick field. In addition to generating processing and pipeline tariff revenue, this third-party business also has a favorable impact on Brae area operations by optimizing infrastructure usage and extending the economic life of the complex.

The Brae group owns a 50 percent interest in the outside-operated SAGE system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 billion cubic feet ("bcf") per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

In the U.K. Atlantic Margin west of the Shetland Islands, we own an average 30 percent working interest in the outside-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, 47 percent working interest in East Foinaven and 20 percent working interest in the T35 and T25 fields. The FPSO is being upgraded which is expected to extend the life of this asset through 2021.

Poland – In 2010, we added 10 licenses with shale gas potential in Poland, increasing our total acreage position to approximately 2.3 million net acres in 11 licenses. We have a 100 percent interest and operate all 11 blocks. In 2011 we plan to acquire 2D seismic over all concessions by the end of the third quarter and plan to initiate drilling in the fourth quarter. We have recently been successful in farming-out a portion of our interest in this play. Under the agreement, our partner will earn a 40 percent working interest in 10 licenses, as well as pay a promote on certain future seismic and well costs. This transaction is subject to the approval of the Polish Ministry of the Environment. We will remain operator of the 10 licenses included in the agreement.

Other International

Indonesia – We are the operator and hold a 70 percent interest in the Pasangkayu Block located both onshore & offshore Sulawesi in the Makassar Strait, Indonesia. The Pasangkayu Block covers an area of approximately 872,000 acres and is located directly east of the Kutei Basin production region. The production sharing contract with the Indonesian government was signed in 2006 and we completed 3D seismic acquisition in May 2008.

In November 2010, the Bravo-1 well in the northeastern portion of the Pasangkayu block was drilled in a water depth of approximately 3,200 feet and reached a total depth of 9,000 feet. No hydrocarbon accumulations were present.

The Romeo prospect, located on the north-central portion of the Pasangkayu block in a water depth of 6,200 feet, is being drilled and is expected to be completed during the first half of 2011.

In 2009, we were awarded a 49 percent interest and operatorship in the Kumawa Block, an Indonesia offshore exploration block, located offshore West Papua. An increase in ownership to 55 percent received Indonesian government approval in late 2010. The Kumawa Block encompasses 1.24 million acres. A seismic survey was acquired in 2010 and we expect to drill one exploration well in 2012.

In October 2008, we were granted a 49 percent interest and operatorship in the Bone Bay Block offshore Sulawesi. An increase in ownership to 55 percent received Indonesian government approval in late 2010. The Bone Bay Block covers an area of 1.23 million acres and is 200 miles southeast of our Pasangkayu Block. A 2D seismic survey was acquired in 2009 and we expect to drill one exploration well in early 2012.

We continue to pursue joint study agreements in Indonesia, which provide a right of first refusal in future bid rounds. We completed one joint study agreement in 2010 and continue to evaluate regional potential for other opportunities.

Iraqi Kurdistan Region – In October 2010, we acquired 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 ("KRG") will hold a 20 percent carried interest. We were assigned working interests in two additional blocks located north-northwest of Erbil; Atrush, in which we have a 16 percent ownership (KRG holds a 4 percent carried interest), and Sarsang, in which we have a 20 ownership (KRG holds a 4 percent carried interest). These contracts provide us with access to approximately 368,000 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 one well currently drilling.

Divestitures

Angola – In February 2010, we closed the sale of an undivided 20 percent interest in the outside-operated production sharing contract and joint operating agreement on Block 32 offshore Angola effective January 1, 2009. We retained a 10 percent interest in Block 32.

The above discussion of the E&P segment includes forward-looking statements with respect to anticipated future exploratory and development drilling, the timing of production from the Ozona development in the Gulf of Mexico, the PSVM development on Block 31 offshore Angola and Block 32 and other possible developments. Some factors which could possible affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, unforeseen hazards such as weather conditions, natural disasters, 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 offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Productive and Drilling Wells

For our E&P segment, the following tables set forth gross and net productive wells and service wells as of December 31, 2010, 2009 and 2008 and drilling wells as of December 31, 2010.

	Productive Wells [(a)]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2010								
United States	4,818	1,860	3,145	1,905	2,466	746	26	16
Equatorial Guinea	-	-	13	9	5	3	-	-
Other Africa	1,022	168	3	-	94	16	11	-
Total Africa	1,022	168	16	9	99	19	11	-
Total Europe	67	28	40	16	29	11	1	-
Total Other International	-	-	-	-	-	-	3	1
Worldwide	5,907	2,056	3,201	1,930	2,594	776	41	17
2009								
United States	4,806	1,788	5,158	3,569	2,447	734		
Equatorial Guinea	-	-	13	9	5	3		
Other Africa	976	160	-	-	91	15		
Total Africa	976	160	13	9	96	18		
Total Europe	67	27	44	18	27	10		
Worldwide	5,849	1,975	5,215	3,596	2,570	762		
2008								
United States	5,856	2,140	5,411	3,846	2,703	822		
Equatorial Guinea	-	-	13	9	5	3		
Other Africa	968	162	-	-	92	15		
Total Africa	968	162	13	9	97	18		
Total Europe	64	26	67	40	26	10		
Worldwide	6,888	2,328	5,491	3,895	2,826	850		

[(a)] Of the gross productive wells, wells with multiple completions operated by us totaled 164, 170 and 276 as of December 31, 2010, 2009 and 2008. Information on wells with multiple completions operated by others is unavailable to us.

Drilling Activity

The following table sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed in each of the last three years.

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2010									
United States	61	20	1	82	29	2	3	34	116
Total Africa	5	-	-	5	1	-	-	1	6
Total Europe	2	-	-	2	-	-	-	-	2
Total Other International	-	-	-	-	1	-	1	2	2
Worldwide	68	20	1	89	31	2	4	37	126
2009									
United States	11	54	2	67	37	9	2	48	115
Total Africa	5	1	-	6	1	-	-	1	7
Total Europe	1	-	-	1	1	-	-	1	2
Worldwide	17	55	2	74	39	9	2	50	124
2008									
United States	38	161	-	199	33	8	6	47	246
Total Africa	6	-	-	6	1	-	-	1	7
Total Europe	2	1	-	3	-	2	1	3	6
Worldwide	46	162	-	208	34	10	7	51	259

Acreage

The following table sets forth, by geographic area, the gross and net developed and undeveloped exploration and production acreage held in our E&P segment as of December 31, 2010.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
United States	1,500	1,100	1,265	1,046	2,765	2,146
Canada	-	-	143	55	143	55
Total North America	1,500	1,100	1,408	1,101	2,908	2,201
Equatorial Guinea	45	29	173	122	218	151
Other Africa	12,909	2,108	2,580	258	15,489	2,366
Total Africa	12,954	2,137	2,753	380	15,707	2,517
Total Europe	131	68	3,044	2,536	3,175	2,604
Other International	-	-	3,985	2,334	3,985	2,334
Worldwide	14,585	3,305	11,190	6,351	25,775	9,656

Of the 6.3 million net undeveloped acres held at December 31, 2010, 3 percent, 13 percent and 4 percent of those acres are under agreements scheduled to expire in the years 2011, 2012, and 2013.

Oil Sands Mining

We hold a 20 percent outside-operated interest in the Athabasca Oil Sands Project ("AOSP"), an oil sands mining joint venture located in Alberta, Canada. The joint venture produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen to synthetic crude oils. The AOSP's mining and extractions assets are located near Fort McMurray, Alberta and include the Muskeg River mine which began bitumen production in 2003 and the Jackpine mine which commenced phased start-up in the third quarter of 2010. As of December 31, 2010, we have rights to participate in developed and undeveloped leases totaling approximately 215,000 gross (45,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. The upgrading assets are located at Fort Saskatchewan, northeast of Edmonton, Alberta.

The first fully integrated expansion of the existing AOSP facilities was approved in 2006. Expansion 1 includes construction of mining and extraction facilities at the Jackpine mine, new treatment facilities at the existing Muskeg River mine, addition of a new processing train at the Scotford upgrader and development of related infrastructure. A phased start-up of the Jackpine mine operations began in the third quarter of 2010. At full capacity, the Jackpine mine will add 100,000 gross bpd to our previously existing capacity. The expanded upgrader began the commissioning and start-up phase, which will continue into early 2011. Stage 1 debottlenecking activities are scheduled to begin in 2011. Potential future expansions and additional debottlenecking opportunities remain under review.

A planned turnaround at the Muskeg River mine and the upgrader occurred from March through May 2010. Our net share of turnaround costs was $99 million. Production as the AOSP was halted in April 2010 before a staged resumption of operations in mid-May 2010.

Current AOSP operations use established processes to mine oil sands deposits from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Ore is mined using traditional truck and shovel mining techniques. The mined ore passes through primary crushers to reduce the ore chunks in size and is then sent to rotary breakers where the ore chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through the extraction process where it separates into sand, clay and bitumen-rich froth. A solvent is added to the bitumen froth to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and produces clean bitumen that is required for the upgrader to run efficiently. The process yields a mixture of solvent and bitumen which is then transported from the mine to the Scotford upgrader via the approximately 300 mile Corridor Pipeline.

The bitumen is upgraded at Scotford using both hydrotreating and hydroconversion processes to remove sulfur and break the heavy bitumen molecules into lighter products. Blendstocks acquired from outside sources are utilized in the production of our saleable products. The three major products that the Scotford upgrader produces are light synthetic crude oil, heavy synthetic crude oil and vacuum gas oil. The vacuum gas oil is sold to an affiliate of the operator under a long term contract at market-related prices, and the other products are sold in the marketplace.

The above discussion of the Oil Sands Mining segment includes forward-looking statements concerning the start-up of the expanded upgrader. Factors which could affect this project include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions and delays or other risks customarily associated with start-up projects.

Reserves

Estimated Reserve Quantities

The following table sets forth estimated quantities of our net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2010 and 2009. Approximately 60 percent of our proved reserves are located in Organization for Economic Cooperation and Development ("OECD") countries.

Reserves are disclosed by continent, by country, if the proved reserves related to any geographic area, on an oil-equivalent barrel basis represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent.

	North America			Africa			Europe	
December 31, 2010	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbon *(mmbbl)*	124	-	124	86	180	266	89	479
Natural gas *(bcf)*	591	-	591	1,186	104	1,290	43	1,924
Synthetic crude oil *(mmbbl)*	-	433	433	-	-	-	-	433
Total proved developed reserves *(mmboe)*	222	433	655	284	198	482	96	1,233
Proved Undeveloped Reserves								
Liquid hydrocarbon *(mmbbl)*	49	-	49	33	59	92	10	151
Natural gas *(bcf)*	154	-	154	465	1	466	73	693
Synthetic crude oil *(mmbbl)*	-	139	139	-	-	-	-	139
Total proved undeveloped reserves *(mmboe)*	75	139	214	110	59	169	22	405
Total Proved Reserves								
Liquid hydrocarbon *(mmbbl)*	173	-	173	119	239	358	99	630
Natural gas *(bcf)*	745	-	745	1,651	105	1,756	116	2,617
Synthetic crude oil *(mmbbl)*	-	572	572	-	-	-	-	572
Total proved reserves *(mmboe)*	297	572	869	394	257	651	118	1,638

	North America			Africa			Europe	
December 31, 2009	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbon *(mmbbl)*	120	-	120	83	186	269	87	476
Natural gas *(bcf)*	652	-	652	1,102	107	1,209	50	1,911
Synthetic crude oil *(mmbbl)*	-	392	392	-	-	-	-	392
Total proved developed reserves *(mmboe)*	229	392	621	267	204	471	95	1,187
Proved Undeveloped Reserves								
Liquid hydrocarbon *(mmbbl)*	50	-	50	39	42	81	15	146
Natural gas *(bcf)*	168	-	168	586	-	586	59	813
Synthetic crude oil *(mmbbl)*	-	211	211	-	-	-	-	211
Total proved undeveloped reserves *(mmboe)*	78	211	289	136	42	178	25	492
Total Proved Reserves								
Liquid hydrocarbon *(mmbbl)*	170	-	170	122	228	350	102	622
Natural gas *(bcf)*	820	-	820	1,688	107	1,795	109	2,724
Synthetic crude oil *(mmbbl)*	-	603	603	-	-	-	-	603
Total proved reserves *(mmboe)*	307	603	910	403	246	649	120	1,679

The following table sets forth estimated quantities of our net proved liquid hydrocarbon and natural gas reserves based upon year end prices as of December 31, 2008.

	North America			Africa			Europe		
December 31, 2008	United States	Canada[a]	Total	EG	Other	Total	Total	Disc. Ops.[b]	Grand Total
Proved Developed Reserves									
Liquid hydrocarbon *(mmbbl)*	137	-	137	99	193	292	81	4	514
Natural gas *(bcf)*	839	-	839	1,273	109	1,382	95	34	2,350
Total proved developed reserves *(mmboe)*	277	-	277	312	211	523	96	10	906
Total Proved Reserves									
Liquid hydrocarbon *(mmbbl)*	178	-	178	139	211	350	104	4	636
Natural gas *(bcf)*	1,085	-	1,085	1,866	109	1,975	159	132	3,351
Total proved reserves *(mmboe)*	359	-	359	450	229	679	131	26	1,195
Developed reserves as a percent of total proved reserves	77%	-	77%	69%	92%	77%	73%	38%	76%

(a) Before December 31, 2009, reserves related to oil sands mining were not included in the SEC's definition of oil and gas producing activities; therefore, these reserves are not reported for 2008.

(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

We previously reported OSM segment reserves as bitumen because oil sands mining was not considered an oil and gas producing activity by the SEC. Proved bitumen reserves reported as of December 31, 2008 were 388 mmboe.

The above estimated quantities of net proved liquid hydrocarbon and natural gas reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. The above estimated quantities of synthetic crude oil reserves are forward-looking statements and are based on presently known physical data, economic recoverability and operating conditions. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates. For additional details of the estimated quantities of proved reserves at the end of each of the last three years, see Item 8. Financial Statements and Supplementary Data— Supplementary Information on Oil and Gas Producing Activities.

Preparation of Reserve Estimates

Our estimation of economically producible volumes of liquid hydrocarbons and natural gas is a highly technical process performed primarily by in-house teams of reservoir engineers and geoscience professionals. All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Beginning December 31, 2009, reserve estimates are based upon the unweighted average of closing prices for the first day of each month in the respective 12-month period ended December 31. In 2008, reserve estimates were based on prices at December 31.

Liquid hydrocarbon, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and her staff of Coordinators. Reserves estimates are developed and reviewed by Qualified Reserves Estimators ("QRE"). QRE are engineers or geoscientists with a minimum of a Bachelor of Science degree in the appropriate technical field, have a minimum of three years of industry experience with at least one year in reserve estimation and have completed Marathon's Qualified Reserve Estimator training course. The Reserve Coordinators review all reserves estimates for all fields with proved reserves greater than 3 mmboe at a minimum of once every three years. Any change to proved reserve estimates in excess of 2.5 mmboe on a total field basis, within a single month, must be approved by Corporate Reserves Group management. All other proved reserve changes must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and a master of business administration. Her 36 years of experience in the industry include 25 with Marathon. She is active in industry and professional groups, having served on the Society of Petroleum Engineers ("SPE") Oil and Gas Reserves Committee ("OGRC") since 2004, chairing in 2008 and 2009. As a member of the OGRC, she participated in the development of the Petroleum Resource Management System ("PRMS") and served on the Technical Program Committee for a 2007 SPE Reserves Estimation Workshop: Sharing the Vision focusing on PRMS. She chaired the development of the OGRC comments on the SEC's proposed modernization of oil and gas reporting and was a member of the American Petroleum Institute's Ad Hoc group that provided comments on the same topic.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants of Calgary, Canada, third-party consultants. A copy of their December 31, 2010 report is filed as Exhibit 99.1 to this Form 10-K. The engineer responsible for the estimates of our oil sands mining reserves has 32 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE, having served as regional director 1998 through 2001 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to audit the in-house reserve estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period. We met this goal for the four-year period ended December 31, 2010, without conducting any third party audits in 2010. We established a tolerance level of 10 percent for reserve audits such that initial estimates by the third-party consultants are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both our team and the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. This resolution process is continued until both estimates are within 10 percent. This process did not result in significant changes to our reserve estimates in 2009 or 2008.

Netherland, Sewell and Associates, Inc. ("NSAI") prepared an independent estimate of December 31, 2008 reserves for the Alba field in Equatorial Guinea. This reserve estimate was used by Corporate Reserves in much the same way third-party audits are now used. The NSAI summary report is Exhibit 99.2 to this Form 10-K. The senior members of the NSAI team have over fifty years of industry experience between them, having worked for large, international oil and gas companies before joining NSAI. The team lead has a master of science in mechanical engineering and is a member of SPE. The senior technical advisor has a bachelor of science in geophysics and is a member of the Society of Exploration Geophysicists, the American Association of Petroleum Geologists and the European Association of Geoscientists and Engineers. Both are licensed in the state of Texas.

Ryder Scott Company ("Ryder Scott") performed audits of several of our fields in 2009. Their summary report on audits performed in 2009 is Exhibit 99.3 to this Form 10-K. The team lead for Ryder Scott has over 19 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He has a bachelor of science in mechanical engineering, is a member of SPE and is a registered Professional Engineer in the state of Texas.

The Corporate Reserves Group may also perform separate, detailed technical reviews of reserve estimates for significant fields that were acquired recently or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

Changes in Proved Undeveloped Reserves

As of December 31, 2010, 405 mmboe of proved undeveloped reserves were reported, a decrease of 87 mmboe from December 31, 2009. The following table shows of the changes in total proved undeveloped reserves for 2010:

Beginning of year	492
Revisions of previous estimates	(30)
Extensions, discoveries, and other additions	71
Transfer to developed	(128)
End of year	405

Significant additions to proved undeveloped reserves during 2010 include 28 mmboe for development drilling in our Libya properties and 19 mmboe additional for development drilling in the Bakken Shale play. Revisions include 26 mmboe of proved undeveloped reserves reclassified as proved developed in Equatorial Guinea because operating pressures can be reduced more than originally anticipated with the existing equipment. Transfers include the movement of 67 mmboe from proved undeveloped to proved developed due to start up for the Jackpine mine Expansion 1 in Canada and 26 mmboe related to the commencement of production at the Gulf of Mexico Droshky development in July 2010. Costs incurred in the periods ended December 31, 2010, 2009 and 2008 relating to the development of proved undeveloped reserves, were $1,463 million, $792 million and $1,189 million.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as behind-pipe zones where reserves will not be accessed until the primary producing zone depletes, large development projects which take more than five years to complete, and the timing of when additional gas compression is needed. Of the 405 mmboe of proved undeveloped reserves at year end 2010, 30 percent of the volume is associated with projects that have been included in proved reserves for more than five years. The majority of this volume is related to a compression project in

Equatorial Guinea that was sanctioned by our Board of Directors in 2004 and is expected to be completed in 2015. The timing of the installation of compression is being deferred as a result of better than expected reservoir performance. In addition, the North Gialo project in Libya is being executed by the operator, encompassing a continuous drilling program and designing, fabricating, and installing extensive liquid handling and gas recycling facilities. In 2010, an engineering firm was awarded the bid for the front-end engineering and design activities. Long lead items are expected to be procured in 2011 and first production is expected in 2016. There are no other significant undeveloped reserves expected to be developed more than five years.

As of December 31, 2010, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves for the years 2011 through 2015 are projected to be $884 million, $315 million, $379 million, $433 million, and $224 million.

The timing of future projects and estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates.

Net Production Sold

	North America			Africa			Europe		
	United States	Canada[(a)]	Total	EG	Other	Total	Total	Disc. Ops[(b)]	Total
Year Ended December 31, 2010									
Liquid hydrocarbon *(mbpd)*[(c)]	70	-	70	38	45	83	92	-	245
Natural gas *(mmcfd)*[(d)(e)]	364	-	364	405	4	409	87	-	860
Synthetic crude oil *(mbpd)*	-	24	24	-	-	-	-	-	24
Total production sold *(mboed)*	131	24	155	106	45	151	106	-	412
Year Ended December 31, 2009									
Liquid hydrocarbon *(mbpd)*[(c)]	64	-	64	42	45	87	92	5	248
Natural gas *(mmcfd)*[(d)(e)]	373	-	373	426	4	430	116	17	936
Total production sold *(mboed)*	126	-	126	113	46	159	111	7	403
Year Ended December 31, 2008									
Liquid hydrocarbon *(mbpd)*[(c)]	63	-	63	40	47	87	55	6	211
Natural gas *(mmcfd)*[(d)(e)]	448	-	448	366	4	370	129	37	984
Total production sold *(mboed)*	138	-	138	101	48	149	77	12	376

(a) Before December 31, 2009, reserves related to oil sands mining were not included in the SEC's definition of oil and gas producing activities; therefore, synthetic crude oil production of 27 mbpd is not reported for 2009.

(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

(c) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(d) U.S. natural gas volumes exclude volumes produced in Alaska that are stored for later sale in response to seasonal demand, although our reserves have been reduced by those volumes.

(e) Excludes volumes acquired from third parties for injection and subsequent resale.

Average Sales Price per Unit

(Dollars per unit)	North America			Africa			Europe		
	United States	Canada[a]	Total	EG	Other	Total	Total	Disc. Ops[b]	Total
Year Ended December 31, 2010									
Liquid hydrocarbon *(bbl)*	$ 72.30	-	$ 72.30	$ 50.57	$ 89.15	$ 71.71	$ 81.95	$ -	$ 75.73
Natural gas *(mcf)*	4.71	-	4.71	0.24	0.70	0.25	7.04	-	2.82
Synthetic crude oil *(bbl)*	-	71.06	71.06	-	-	-	-	-	71.06
Year Ended December 31, 2009									
Liquid hydrocarbon *(bbl)*	54.67	-	54.67	38.06	68.41	53.91	64.46	56.47	58.06
Natural gas *(mcf)*	4.14	-	4.14	0.24	0.70	0.25	4.84	8.54	2.52
Year Ended December 31, 2008									
Liquid hydrocarbon *(bbl)*	86.68	-	86.68	66.34	110.49	89.85	90.60	96.41	89.29
Natural gas *(mcf)*	7.01	-	7.01	0.24	0.70	0.25	7.80	9.62	4.67

(a) Before December 31, 2009, oil sands mining was not included in the SEC's definition of oil and gas producing activities; therefore, synthetic crude oil prices are not reported for 2009 or 2008.
(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

Average Production Cost per Unit[a]

(Dollars per boe)	North America			Africa			Europe		
	United States	Canada[b]	Total	EG	Other	Total	Total	Disc. Ops[c]	Grand Total
Years ended December 31:									
2010	$ 14.16	$ 65.15	$ 22.36	$ 2.81	$ 4.18	$ 3.23	$ 7.49	$ -	$ 11.54
2009	14.03	-	14.03	2.63	3.64	2.93	6.99	19.14	7.80
2008	12.82	-	12.82	2.57	2.39	2.51	11.72	15.24	8.61

(a) Production, severance and property taxes are excluded from the production costs used in calculation of this metric.
(b) Before December 31, 2009, oil sands mining was not included in the SEC's definition of oil and gas producing activities; therefore, production costs are not reported for 2009 or 2008. Production costs in 2010 include costs associated with a major turnaround.
(c) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

Integrated Gas

Our integrated gas operations include natural gas liquefaction and regasification operations and methanol production operations. Also included in the financial results of the Integrated Gas segment are the costs associated with ongoing development of projects to link stranded natural gas resources with key demand areas.

We hold a 60 percent interest in EGHoldings, which is accounted for under the equity method of accounting. EGHoldings has a 3.7 million metric tonnes per annum ("mmtpa") LNG production facility on Bioko Island in Equatorial Guinea. LNG from the production facility is sold under a 3.4 mmtpa, or 460 mmcfd, sales and purchase agreement with a 17-year term ending in 2024. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index, regardless of destination. This production facility allows us to monetize our natural gas reserves from the Alba field, as natural gas for the facility is purchased from the Alba field participants under a long-term natural gas supply agreement. Gross sales of LNG from this production facility totaled 3.7 million metric tonnes in 2010. In 2010, we continued discussions with the government of Equatorial Guinea and our partners regarding a potential second LNG production facility on Bioko Island.

We own a 30 percent outside-operated interest in a natural gas liquefaction plant in Kenai Alaska. This facility began first production in 1969 and we currently lease one 87,500 cubic meter tankers to transport LNG to customers in Japan. In February 2011 we, along with the plant operator, announced that exports would cease in spring of 2011.

We own a 45 percent interest in AMPCO, which is accounted for under the equity method of accounting. AMPCO owns a methanol plant located in Malabo, Equatorial Guinea. Feedstock for the plant is supplied from our natural gas production from the Alba field. Gross sales of methanol from the plant totaled 850,605 metric tonnes in 2010. Production from the plant is used to supply customers in Europe and the U.S.

The above discussion of the Integrated Gas segment contains forward-looking statements with respect to the possible expansion of the LNG production facility in Equatorial Guinea. Factors that could potentially affect the possible expansion of the LNG production facility include partner and government approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Refining, Marketing and Transportation

We have refining, marketing and transportation operations concentrated primarily in the Midwest, Gulf Coast and Southeast regions of the U.S. We rank as the fifth largest crude oil refiner in the U.S. and the largest in the Midwest. Our operations include a six-plant refining network and an integrated terminal and transportation system which supplies wholesale and Marathon-brand customers as well as our own retail operations. Our wholly-owned retail marketing subsidiary Speedway LLC ("Speedway") is one of the largest company-owned and -operated retail gasoline and convenience stores in the U.S.

In December 2010, we sold our St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments and 166 SuperAmerica retail outlets (collectively, "Minnesota Assets"). Operations for the Minnesota Assets are included in all of the annual statistics reported.

Refining

We currently own and operate six refineries with an aggregate refining capacity of 1,142 thousand barrels per day ("mbpd") of crude oil as detailed in the table below.

Crude Oil Refining Capacity

(mbpd)	
Garyville, Louisiana	464
Catlettsburg, Kentucky	212
Robinson, Illinois	206
Detroit, Michigan	106
Canton, Ohio	78
Texas City, Texas	76
Total	1,142

During 2010, our refineries processed 1,173 mbpd of crude oil and 162 mbpd of other charge and blend stocks. Our refineries include crude oil atmospheric and vacuum distillation, fluid catalytic cracking, catalytic reforming, desulfurization and sulfur recovery units. The refineries process a wide variety of crude oils and produce numerous refined products, ranging from transportation fuels, such as reformulated gasolines, blend-grade gasolines intended for blending with fuel ethanol and ultra-low sulfur diesel fuel, to heavy fuel oil and asphalt. Additionally, we manufacture aromatics, cumene, propane, propylene, and sulfur.

Our Garyville, Louisiana, refinery is located along the Mississippi River in southeastern Louisiana between New Orleans and Baton Rouge. The Garyville refinery is configured to processes heavy sour crude oil into products such as gasoline, distillates, sulfur, asphalt, propane, polymer grade propylene, isobutane and coke. An expansion project was completed in the fourth quarter of 2009 that increased Garyville's crude oil refining capacity, making it one of the largest refineries in the U.S. Our Garyville refinery has earned designation as a U.S. Occupational Safety and Health Administration (OSHA) Voluntary Protection Program (VPP) STAR site.

Our Catlettsburg, Kentucky, refinery is located in northeastern Kentucky on the western bank of the Big Sandy River, near the confluence with the Ohio River. The Catlettsburg refinery processes sweet and sour crude oils into products such as gasoline, asphalt, diesel, jet fuel, petrochemicals, propane, propylene and sulfur.

Our Robinson, Illinois, refinery is located in southeastern Illinois. The Robinson refinery processes sweet and sour crude oils into products such as multiple grades of gasoline, jet fuel, kerosene, diesel fuel, propane, propylene, sulfur and anode-grade coke. The Robinson refinery has earned designation as an OSHA VPP STAR site.

Our Detroit, Michigan, refinery is located near Interstate 75 in southwest Detroit. It is the only petroleum refinery currently operating in Michigan. The Detroit refinery processes light sweet and heavy sour crude oils, including Canadian crude oils, into products such as gasoline, diesel, asphalt, slurry, propane, chemical grade propylene and sulfur. In 2007, we approved a heavy oil upgrading and expansion project at this refinery, with a current projected cost of $2.2 billion (excluding capitalized interest). This project will enable the refinery to process an additional 80 mbpd of heavy sour crude oils, including Canadian bitumen blends, and will increase its crude oil refining capacity by about 15 mbpd. Construction began in the first half of 2008 and reached 50 percent completion at December 31, 2010. The project is expected to be complete in the second half of 2012. Our Detroit refinery is certified as a Michigan VPP STAR site.

Our Canton, Ohio, refinery is located approximately 60 miles southeast of Cleveland, Ohio. The Canton refinery processes sweet and sour crude oils into products such as gasoline, diesel fuels, kerosene, propane, sulfur, asphalt, roofing flux, home heating oil and No. 6 industrial fuel oil.

Our Texas City, Texas, refinery is located on the Texas Gulf Coast approximately 30 miles south of Houston, Texas. The refinery processes sweet crude oil into products such as gasoline, propane, chemical grade propylene, slurry, sulfur and aromatics.

The above discussion includes forward-looking statements concerning the Detroit refinery heavy oil upgrading and expansion project. Some 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.

Our refineries are integrated with each other via pipelines, terminals and barges to maximize operating efficiency. The transportation links that connect our refineries allow the movement of crude oil, feedstocks and intermediate products between refineries to optimize operations, produce higher margin products and utilize our processing capacity efficiently.

The following table sets forth our refinery production by product group for each of the last three years.

Refined Product Yields

(mbpd)	2010	2009	2008
Gasoline	726	669	609
Distillates	409	326	342
Propane	24	23	22
Feedstocks and special products	97	62	96
Heavy fuel oil	24	24	24
Asphalt	76	66	75
Total	1,356	1,170	1,168

Crude oil supply – We obtain most of the crude oil we refine through negotiated contracts and purchases or exchanges on the spot market. Our crude oil supply contracts are generally term contracts with market related pricing provisions. The following table provides information on our sources of crude oil for each of the last three years. The crude oil sourced outside of North America was acquired from various foreign national oil companies, producing companies and trading companies.

Sources of Crude Oil Refined

(mbpd)	2010	2009	2008
United States	720	613	466
Canada	115	136	135
Middle East and Africa	250	154	244
Other international	88	54	99
Total	1,173	957	944
Average cost of crude oil throughput *(Dollars per barrel)*	$78.57	$62.10	$98.34

Our refineries receive crude oil and other feedstocks and distribute our refined products through a variety of channels, including pipelines, trucks, railcars, ships and barges.

Refined products marketing and distribution – We are a supplier of refined products to resellers and consumers within our 20-state market area in the Midwest, Gulf Coast and southeastern regions of the United States. Our market area includes approximately 5,100 Marathon branded-retail outlets concentrated in the Midwest and southeastern states. We currently own and distribute from 63 light product and 21 asphalt terminals. In addition, we distribute light products through approximately 45 third-party terminals in our market area. Our marine transportation operations include 14 towboats, as well as 168 owned and 8 leased barges that transport refined products on the Ohio, Mississippi and Illinois rivers and their tributaries as well as the Intercoastal Waterway. We lease or own approximately 1,760 railcars of various sizes and capacities for movement and storage of refined products. In addition, we own 122 transport trucks for the movement of refined products.

The following table sets forth, as a percentage of total refined product sales, sales of refined products to our different customer types for the past three years.

Refined Product Sales by Customer Type	2010	2009	2008
Private-brand marketers, commercial and industrial consumers	70%	67%	67%
Marathon-branded outlets	17%	18%	18%
Speedway retail outlets	13%	15%	15%

The following table sets forth our refined products sales by product group and our average sales price for each of the last three years.

Refined Product Sales

(mbpd)	2010	2009	2008
Gasoline	923	830	756
Distillates	435	357	375
Propane	24	23	22
Feedstocks and special products	103	75	100
Heavy fuel oil	23	24	23
Asphalt	77	69	76
Total	1,585	1,378	1,352
Average sales price *(Dollars per barrel)*	$ 87.87	$ 70.86	$ 109.49

We sell gasoline, gasoline blendstocks and No. 1 and No. 2 fuel oils (including kerosene, jet fuel and diesel fuel) to wholesale marketing customers in the Midwest, Gulf Coast and southeastern regions of the U.S. We sold 54 percent of our gasoline volumes and 88 percent of our distillates volumes on a wholesale or spot market basis in 2010. The demand for gasoline is seasonal in many of our markets, with demand typically being at its highest levels during the summer months.

We have blended ethanol into gasoline for over 20 years and expanded our blending program in 2007, in part due to federal regulations that require us to use specified volumes of renewable fuels. Ethanol volumes sold in blended gasoline averaged 68 mbpd in 2010, 60 mbpd in 2009 and 54 mbpd in 2008. The future expansion or contraction of our ethanol blending program will be driven by the economics of the ethanol supply and by government regulations. We sell reformulated gasoline, which is also blended with ethanol, in parts of our marketing territory, including: Chicago, Illinois; Louisville, Kentucky; northern Kentucky; and Milwaukee, Wisconsin. We also sell biodiesel-blended diesel in Illinois, Kentucky and Pennsylvania.

We produce propane at all six of our refineries. Propane is primarily used for home heating and cooking, as a feedstock within the petrochemical industry, for grain drying and as a fuel for trucks and other vehicles. Our propane sales are typically split evenly between the home heating market and industrial consumers.

We are a producer and marketer of petrochemicals and specialty products. Product availability varies by refinery and includes benzene, cumene, dilute naphthalene oil, molten sulfur, propylene, toluene and xylene. We market propylene, cumene and sulfur domestically to customers in the chemical industry. We also have the capacity to produce 1,400 tons per day of anode grade coke at our Robinson refinery, which is used to make carbon anodes for the aluminum smelting industry, and 5,600 tons per day of fuel grade coke at the Garyville refinery, which is used for power generation and in miscellaneous industrial applications.

We produce and market heavy residual fuel oil or related components at all six of our refineries. Heavy residual fuel oil is primarily used in the utility and ship bunkering (fuel) industries, though there are other more specialized uses of the product.

We have refinery based asphalt production capacity of up to 92 mbpd. We market asphalt through 33 owned or leased terminals throughout the Midwest and Southeast. We have a broad customer base, including approximately 641 asphalt-paving contractors, government entities (states, counties, cities and townships) and asphalt roofing shingle manufacturers. We sell asphalt in the wholesale and cargo markets via rail and barge. We also produce asphalt cements, polymer modified asphalt, emulsified asphalt and industrial asphalts.

We hold a 35 percent interest in an entity which owns and operates a 110-million-gallon-per-year ethanol production facility in Clymers, Indiana. We also own a 50 percent interest in an entity which owns a 110-million-gallon-per-year ethanol production facility in Greenville, Ohio. Both of these facilities are managed by a co-owner.

Pipeline transportation – We own a system of pipelines through Marathon Pipe Line LLC ("MPL") and Ohio River Pipe Line LLC ("ORPL"), our wholly-owned subsidiaries. Our pipeline systems transport crude oil and refined products primarily in the Midwest and Gulf Coast regions to our refineries, our terminals and other pipeline systems. Our MPL and ORPL wholly-owned and undivided interest common carrier systems consist of 1,707 miles of crude oil lines and 1,825 miles of refined product lines comprising 31 systems located in 11 states. The MPL common carrier pipeline network is one of the largest petroleum pipeline systems in the U.S., based on total barrels delivered. Our common carrier pipeline systems are subject to state and Federal Energy Regulatory Commission regulations and guidelines, including published tariffs for the transportation of crude oil and refined products. Third parties generated 11 percent of the crude oil and refined product shipments on our MPL and ORPL common carrier pipelines in 2010. Our MPL and ORPL common carrier pipelines transported the volumes shown in the following table for each of the last three years.

Pipeline Barrels Handled

(mbpd)	2010	2009	2008
Crude oil trunk lines	1,204	1,279	1,405
Refined products trunk lines	968	953	960
Total	2,172	2,232	2,365

We also own 175 miles of private crude oil pipelines and 846 miles of private refined products pipelines, and we lease 217 miles of common carrier refined product pipelines. We have partial ownership interests in several pipeline companies that have approximately 110 miles of crude oil pipelines and 3,600 miles of refined products pipelines, including about 970 miles operated by MPL. In addition, MPL operates most of our private pipelines and 985 miles of crude oil and 160 miles of natural gas pipelines owned by our E&P segment.

Our major refined product pipelines include the owned and operated Cardinal Products Pipeline and the Wabash Pipeline. The Cardinal Products Pipeline delivers refined products from Kenova, West Virginia, to Columbus, Ohio. The Wabash Pipeline system delivers product from Robinson, Illinois, to various terminals in the area of Chicago, Illinois. Other significant refined product pipelines owned and operated by MPL extend from: Robinson, Illinois, to Louisville, Kentucky; Garyville, Louisiana, to Zachary, Louisiana; and Texas City, Texas, to Pasadena, Texas.

In addition, as of December 31, 2010, we had interests in the following refined product pipelines:

- 65 percent undivided ownership interest in the Louisville-Lexington system, a petroleum products pipeline system extending from Louisville to Lexington, Kentucky;
- 60 percent interest in Muskegon Pipeline LLC, which owns a refined products pipeline extending from Griffith, Indiana, to North Muskegon, Michigan;
- 50 percent interest in Centennial Pipeline LLC, which owns a refined products system connecting the Gulf Coast region with the Midwest market;
- 17 percent interest in Explorer Pipeline Company, a refined products pipeline system extending from the Gulf Coast to the Midwest; and
- 6 percent interest in Wolverine Pipe Line Company, a refined products pipeline system extending from Chicago, Illinois, to Toledo, Ohio.

Our major owned and operated crude oil lines run from: Patoka, Illinois, to Catlettsburg, Kentucky; Patoka, Illinois, to Robinson, Illinois; Patoka, Illinois, to Lima, Ohio; Lima, Ohio to Canton, Ohio; Samaria, Michigan, to Detroit, Michigan; and St. James, Louisiana, to Garyville, Louisiana.

As of December 31, 2010, we had interests in the following crude oil pipelines:

- 51 percent interest in LOOP LLC, the owner and operator of LOOP, which is the only U.S. deepwater oil port, located 18 miles off the coast of Louisiana, and a crude oil pipeline connecting the port facility to storage caverns and tanks at Clovelly, Louisiana;
- 59 percent interest in LOCAP LLC, which owns a crude oil pipeline connecting LOOP and the Capline system;
- 33 percent undivided joint interest in the Capline system, a large-diameter crude oil pipeline extending from St. James, Louisiana, to Patoka, Illinois;
- 26 percent undivided joint interest in the Maumee Pipeline System, a large diameter crude oil pipeline extending from Lima, Ohio, to Samaria, Michigan.

We plan to construct, by the end of 2012, a new section of pipeline connecting an existing pipeline to our Detroit refinery which will allow us to deliver additional supplies of Canadian crude.

The above discussion contains forward looking statements with respect to the plans to construct a new section of pipeline. Factors which could affect these plans 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.

Retail Marketing

Speedway, our wholly-owned subsidiary headquartered in Enon, Ohio, sells gasoline and merchandise through owned and operated retail outlets primarily under the Speedway® brand. Diesel fuel is also sold at a number of these outlets. Speedway retail outlets offer a wide variety of merchandise, such as prepared foods, beverages, and non-food items, as well as a significant number of proprietary items. For eleven consecutive quarters ending September 30, 2010, Speedway has been rated as the best convenience store chain in terms of overall customer satisfaction in a national consumer perception survey conducted by Corporate Research International®. In 2010, Harris Interactive's EquiTrend® annual brand equity study named Speedway® the number one gasoline brand with consumers for the second year in a row. Speedway's Speedy Rewards™, an industry-leading customer loyalty program, has built active membership to 3.5 million customers.

As of December 31, 2010, Speedway had 1,358 retail outlets in seven states. Sales of refined products through these retail outlets accounted for 13 percent of our refined product sales volumes in 2010 and provide us with a base of ratable sales. Revenues from sales of non-petroleum merchandise through these retail outlets totaled $3,195 million in 2010, $3,109 million in 2009 and $2,838 million in 2008. The demand for gasoline is seasonal in a majority of Speedway markets, with the highest demand usually occurring during the summer driving season. Margins from the sale of merchandise and services tend to be less volatile than margins from the retail sale of gasoline and diesel fuel.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration for and development of new reserves. We compete with major integrated and independent oil and gas companies, as well as national oil companies, for the acquisition of oil and natural gas leases and other properties. We compete with these companies for the equipment and labor required to develop and operate those properties and in the marketing of oil and natural gas to end-users. Many of our competitors have financial and other resources greater than those available to us. Acquiring exploration opportunities frequently requires competitive bids involving front-end bonus payments or commitments-to-work programs. We also compete in attracting and retaining personnel, including geologists, geophysicists and other specialists. Based upon statistics compiled in the "2010 Global Upstream Performance Review" published by IHS Herold Inc., we rank ninth among U.S.-based petroleum companies on the basis of 2009 worldwide liquid hydrocarbon and natural gas production.

We also compete with other producers of synthetic and conventional crude oil for the sale of our synthetic crude oil to refineries primarily in North America. Additional synthetic crude oil projects are being contemplated by various competitors and, if undertaken and completed, these projects may result in a significant increase in the supply of synthetic crude oil to the market. Since not all refineries are able to process or refine synthetic crude oil in significant volumes, there can be no assurance that sufficient market demand will exist at all times to absorb our share of the synthetic crude oil production from the AOSP at economically viable prices.

We must also compete with a large number of other companies to acquire crude oil for refinery processing and in the distribution and marketing of a full array of petroleum products. Based upon the "The Oil & Gas Journal 2010 Worldwide Refinery Survey", we rank fifth among U.S. petroleum companies on the basis of U.S. crude oil refining capacity as of December 31, 2010. We compete in four distinct markets for the sale of refined products – wholesale, spot, branded and retail distribution. We believe we compete with about 56 companies in the sale of refined products to wholesale marketing customers, including private-brand marketers and large commercial and industrial consumers; about 91 companies in the sale of refined products in the spot market; ten refiners or marketers in the supply of refined products to refiner branded jobbers and dealers; and approximately 252 retailers in the retail sale of refined products. (A jobber is a business that does not carry out refining operations but supplies refiner-branded products to gasoline stations or convenience stores. Dealers refer to retail service station or convenience store operators affiliated with a brand identity.) We compete in the convenience store industry through Speedway's retail outlets. The retail outlets offer consumers gasoline, diesel fuel (at selected locations) and a broad mix of other merchandise and services. Several nontraditional fuel retailers, such as supermarkets, club stores and mass merchants, have affected the convenience store industry and Energy Analysts International, Inc. estimates such retailers had 12 percent of the U.S. gasoline market in 2010.

Our operating results are affected by price changes in conventional and synthetic crude oil, natural gas and petroleum products, as well as changes in competitive conditions in the markets we serve. Generally, results from production and oil sands mining operations benefit from higher crude oil prices while the refining and wholesale marketing gross margin may be adversely affected by crude oil price increases. Price differentials between sweet and sour crude oil also affect operating results. Market conditions in the oil and gas industry are cyclical and subject to global economic and political events and new and changing governmental regulations.

Environmental Matters

The Public Policy Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Crisis Management Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

State, national and international legislation to reduce greenhouse gas emissions are being proposed and, in some cases, promulgated. This legislation applies or could apply in countries in which we operate. Potential legislation and regulations pertaining to climate change could also affect our operations. The cost to comply with these laws and regulations cannot be estimated at this time, but could be significant. For additional information, see Item 1A. Risk Factors. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Our businesses are also subject to numerous other laws and regulations relating to the protection of the environment. These environmental laws and regulations include the Clean Air Act ("CAA") with respect to air emissions, the Clean Water Act ("CWA") with respect to water discharges, the Resource Conservation and Recovery Act ("RCRA") with respect to solid and hazardous waste treatment, storage and disposal, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") with respect to releases and remediation of hazardous substances and the Oil Pollution Act of 1990 ("OPA-90") with respect to oil pollution and response. In addition, many states where we operate have their own similar laws dealing with similar matters. New laws are being enacted, and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new rules can only be broadly appraised until their implementation becomes more accurately defined. In some cases, they can impose liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. The ultimate impact of complying with existing laws and regulations is not clearly known or determinable because certain implementing regulations for some environmental laws have not yet been finalized or, in some instances, are undergoing revision. These environmental laws and regulations, particularly the 1990 Amendments to the CAA and its implementing regulations, new water quality requirements and stricter fuel regulations, could result in increased capital, operating and compliance costs.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

Air

The U.S. Environmental Protection Agency ("EPA") is in the process of implementing regulations to address the National Ambient Air Quality Standards ("NAAQS") for fine particulate emissions and ozone. In connection with these standards, the EPA will designate certain areas as "nonattainment," meaning that the air quality in such areas does not meet the NAAQS. The proposed rule is directed at electric generating units, not refineries, and is expected to be finalized in 2011. However, we cannot reasonably estimate any final financial impact of the state actions to implement the CATR until the EPA has issued a final rule and states have taken further action to implement that rule.

The EPA is reviewing and is proposing to revise, all NAAQS for criteria air pollutants. In January, 2010, the EPA issued the final nitrogen dioxide standard. In addition, in June 2010, the EPA published the final standard for sulfur dioxide. In December 2010, the EPA announced that the final ozone rule will be completed by July 29, 2011. We cannot reasonably estimate the final financial impact of these revised NAAQS standards until the implementing rules are established and judicial challenges over the revised NAAQS standards are resolved.

Water

We maintain numerous discharge permits as required under the National Pollutant Discharge Elimination System program of the CWA and have implemented systems to oversee our compliance efforts. In addition, we are regulated under OPA-90, which amended the CWA. Among other requirements, OPA-90 requires the owner or operator of a tank vessel or a facility to maintain an emergency plan to respond to releases of oil or hazardous substances. Also, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions.

Additionally, OPA-90 requires that new tank vessels entering or operating in U.S. waters be double-hulled and that existing tank vessels that are not double-hulled be retrofitted or removed from U.S. service, according to a phase-out schedule. All of the barges used for river transport of our raw materials and refined products meet the double-hulled requirements of OPA-90. We operate facilities at which spills of oil and hazardous substances could occur. Some coastal states in which we operate have passed state laws similar to OPA-90, but with expanded liability provisions, including provisions for cargo owner responsibility as well as ship owner and operator responsibility. We have implemented emergency oil response plans for all of our components and facilities covered by OPA-90, and we have established Spill Prevention, Control and Countermeasures ("SPCC") plans for facilities subject to CWA SPCC requirements.

Solid Waste

We continue to seek methods to minimize the generation of hazardous wastes in our operations. The RCRA establishes standards for the management of solid and hazardous wastes. Besides affecting waste disposal practices, RCRA also addresses the environmental effects of certain past waste disposal operations, the recycling of wastes and the regulation of underground storage tanks ("USTs") containing regulated substances. We have ongoing RCRA treatment and disposal operations at one of our RM&T facilities and primarily utilize offsite third-party treatment and disposal facilities.

Remediation

We own or operate certain retail outlets where, during the normal course of operations, releases of refined products from USTs have occurred. Federal and state laws require that contamination caused by such releases at these sites be assessed and remediated to meet applicable standards. The enforcement of the UST regulations under RCRA has been delegated to the states, which administer their own UST programs. Our obligation to remediate such contamination varies, depending on the extent of the releases and the stringency of the laws and regulations of the states in which we operate. A portion of these remediation costs may be recoverable from the appropriate state UST reimbursement funds once the applicable deductibles have been satisfied. We also have other facilities which are subject to remediation under federal or state law. See Item 3. Legal Proceedings – Environmental Proceedings – Other Proceedings for a discussion of these sites.

The AOSP operations use established processes to mine deposits of bitumen from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Tailings are waste products created from the oil sands extraction process which are placed in ponds. The AOSP is required to reclaim its tailing ponds as part of its ongoing reclamation work. The reclamation process uses developing technology and there is an inherent risk that the current process may not be as effective or perform as required in order to meet the approved closure and reclamation plan. The AOSP continues to develop its current reclamation technology and continues to investigate other alternate tailings management technologies. In February 2009, the Alberta Energy Resources Conservation Board ("ERCB") issued a directive which more clearly defines criteria for managing oil sands tailings. The AOSP Joint Venture Operator submitted tailings management papers to the ERCB (for both mines), that sets forth plans to comply with the Directive and received approval (with conditions) in the second half of 2010. Further new regulations or failure to comply (in a timely manner) could result in additional cost to us.

Other Matters

In 2007, the U.S. Congress passed the Energy Independence and Security Act ("EISA"), which, among other things, sets a target of 35 miles per gallon for the combined fleet of cars and light trucks in the United States by model year 2020, and contains a second Renewable Fuel Standard ("RFS2"). The EPA announced the final RFS2 regulations on February 4, 2010. The RFS2 requires 12.95 billion gallons of renewable fuel usage in 2010, increasing to 36.0 billion gallons by 2022. In the near term, the RFS2 will be satisfied primarily with fuel ethanol blended into gasoline. The RFS2 presents production and logistic challenges for both the fuel ethanol and petroleum refining industries. The RFS2 has required, and will likely in the future continue to require, additional capital expenditures or expenses by us to accommodate increased fuel ethanol use. Within the overall 36.0 billion gallon RFS2, EISA establishes an advanced biofuel RFS2 that begins with 0.95 billion gallons in 2010 and increases to 21.0 billion gallons by 2022. Subsets within the advanced biofuel RFS2 include 1.15 billion gallons of biomass-based diesel in 2010 (due to combining the 2009 and 2010 volumes), which is capped at 1.0 billion gallons starting in 2012, and 0.1 billion gallons of cellulosic biofuel in 2010, increasing to 16.0 billion gallons by 2022. The EPA has determined that 0.1 billion gallons of cellulosic biofuel will not be produced in 2010 and has lowered the requirement to 5.0 million gallons. The advanced biofuels programs will present specific challenges in that we may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, including biomass-based diesel and cellulosic biofuel, with potentially uncertain supplies of these new fuels. There will be compliance costs and uncertainties regarding how we will comply with the various requirements contained in this law and related regulations. We may experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

On October 13, 2010, the EPA issued a partial waiver decision under the CAA to allow for an increase in the amount of ethanol permitted to be blended into gasoline from 10 percent ("E10") to 15 percent ("E15") for 2007 and newer light-duty motor vehicles. There are numerous state and federal regulatory issues that would need to be addressed before E15 can be marketed for use in any traditional gasoline engines.

The USX Separation

On December 31, 2001, pursuant to an Agreement and Plan of Reorganization dated as of July 31, 2001, Marathon completed the USX Separation, in which:

- its wholly-owned subsidiary United States Steel LLC converted into a Delaware corporation named United States Steel Corporation and became a separate, publicly traded company; and
- USX Corporation changed its name to Marathon Oil Corporation.

As a result of the USX Separation, Marathon and United States Steel are separate companies and neither has any ownership interest in the other.

In connection with the USX Separation and pursuant to the Plan of Reorganization, Marathon and United States Steel have entered into a series of agreements governing their relationship after the USX Separation and providing for the allocation of tax and certain other liabilities and obligations arising from periods before the USX Separation. The following is a description of the material terms of one of those agreements.

Financial Matters Agreement

Under the financial matters agreement, United States Steel has assumed and agreed to discharge all of our principal repayment, interest payment and other obligations under the following, including any amounts due on any default or acceleration of any of those obligations, other than any default caused by us:

- obligations under industrial revenue bonds related to environmental projects for current and former U.S. Steel Group facilities, with maturities ranging from 2011 through 2033;
- sale-leaseback financing obligations under a lease for equipment at United States Steel's Fairfield Works facility, with a lease term to 2012, subject to extensions;
- obligations relating to various lease arrangements accounted for as operating leases and various guarantee arrangements, all of which were assumed by United States Steel; and
- certain other guarantees.

The financial matters agreement also provides that, on or before December 31, 2011, United States Steel will provide for our discharge from any remaining liability under any of the assumed industrial revenue bonds. United States Steel may accomplish that discharge by refinancing or, to the extent not refinanced, paying us an amount equal to the remaining principal amount of all accrued and unpaid debt service outstanding on, and any premium required to immediately retire, the then outstanding industrial revenue bonds.

Under the financial matters agreement, United States Steel has all of the existing contractual rights under the leases assumed from us, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed lease obligations without our prior consent other than extensions set forth in the terms of the assumed leases.

The financial matters agreement requires us to use commercially reasonable efforts to assure compliance with all covenants and other obligations to avoid the occurrence of a default or the acceleration of the payments on the assumed obligations.

United States Steel's obligations to us under the financial matters agreement are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. The financial matters agreement does not contain any financial covenants and United States Steel is free to incur additional debt, grant mortgages on or security interests in its property and sell or transfer assets without our consent.

Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. While no single customer accounts for more than 10 percent of annual revenues, we have exposures to United States Steel arising from the transaction discussed in Note 3 to the consolidated financial statements.

Trademarks, Patents and Licenses

We currently hold a number of U.S. and foreign patents and have various pending patent applications. Although in the aggregate our trademarks, patents and licenses are important to us, we do not regard any single trademark, patent, license or group of related trademarks, patents or licenses as critical or essential to our business as a whole.

Employees

We had 29,677 active employees as of December 31, 2010. Of that number, 19,147 were employees of Speedway, most of whom were employed at our retail marketing outlets.

Certain hourly employees at our Catlettsburg and Canton refineries are represented by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers Union under labor agreements that expire on January 31, 2012. Certain employees at our Texas City refinery are represented by the same union under a labor agreement that expires on March 31, 2012.

The International Brotherhood of Teamsters represents certain hourly employees at our Detroit refinery under a labor agreement that is scheduled to expire on January 31, 2014. They also represent employees at the St. Paul Park refinery under a labor agreement that is scheduled to expire on May 31, 2012. The St. Paul Park Refinery was sold effective December 1, 2010, however there is a transition services agreement in place. Due to this agreement, we remain subject to the labor contracts until the employee transfer date. See Item 8. Financial Statements and Supplementary Data—Note 6 for transaction details.

Executive Officers of the Registrant

The executive officers of Marathon and their ages as of February 1, 2011, are as follows:

Clarence P. Cazalot, Jr.	60	President and Chief Executive Officer
Janet F. Clark	56	Executive Vice President and Chief Financial Officer
Eileen M. Campbell	53	Vice President, Public Policy
Gary R. Heminger	57	Executive Vice President, Downstream
Sylvia J. Kerrigan	45	Vice President, General Counsel and Secretary
Paul C. Reinbolt	55	Vice President, Finance and Treasurer
David E. Roberts, Jr.	50	Executive Vice President, Upstream
Michael K. Stewart	53	Vice President, Accounting and Controller
Howard J. Thill	51	Vice President, Investor Relations and Public Affairs

With the exception of Mr. Roberts, all of the executive officers have held responsible management or professional positions with Marathon or its subsidiaries for more than the past five years.

- Mr. Cazalot was appointed president and chief executive officer effective January 2002.
- Ms. Clark was appointed executive vice president effective January 2007. Ms. Clark joined Marathon in January 2004 as senior vice president and chief financial officer.
- Ms. Campbell was appointed vice president, public policy effective June 2010. Prior to this appointment, Ms. Campbell was Vice President, Human Resources since October 2000.
- Mr. Heminger was appointed executive vice president, downstream effective July 2005. Mr. Heminger has served as president of Marathon Petroleum Company LP since September 2001.
- Ms. Kerrigan was appointed vice president, general counsel and secretary effective November 1, 2009. Prior to this appointment, Ms. Kerrigan was assistant general counsel since January 1, 2003.
- Mr. Reinbolt was appointed vice president, finance and treasurer effective January 2002.
- Mr. Roberts joined Marathon in June 2006 as senior vice president, business development and was appointed executive vice president, upstream in April 2008. Prior to joining Marathon, he was employed by BG Group from 2003 as executive vice president/managing director responsible for Asia and the Middle East.
- Mr. Stewart was appointed vice president, accounting and controller effective May 2006. Mr. Stewart previously served as controller from July 2005 to April 2006. Prior to his appointment as controller, Mr. Stewart was director of internal audit from January 2002 to June 2005.
- Mr. Thill was appointed vice president, investor relations and public affairs effective January 2008. Mr. Thill was previously director of investor relations from April 2003 to December 2007.

Available Information

General information about Marathon, including the Corporate Governance Principles and Charters for the Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Public Policy Committee, can be found at www.marathon.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available at http://www.marathon.com/Investor_Center/.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations.

The proposed spin-off of MPC is contingent upon the satisfaction of a number of conditions, which may not be consummated on the terms or timeline currently contemplated or may not achieve the intended results.

We expect that the spin-off will be effective June 30, 2011. Our ability to timely effect the spin-off is subject to several conditions, including among others, the receipt of a favorable private letter ruling from the IRS, an independent tax opinion that the distribution of one share of MPC common stock for every two shares of Marathon will qualify as tax-free and the SEC declaring effective the registration statement. We cannot assure that we will be able to complete the spin-off in a timely fashion, if at all. For these and other reasons, the spin-off may not be completed on the terms or timeline contemplated. Further, if the spin-off is completed, it may not achieve the intended results. Any such difficulties could adversely affect our business, results of operations or financial condition.

The spin-off could result in substantial tax liability.

We have requested a private letter ruling from the Internal Revenue Service ("IRS") substantially to the effect that, for U.S. federal income tax purposes, the spin-off and certain related transactions will qualify under Sections 355 and/or 368 of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under section 355 of the Code. The private letter ruling will be based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also intend to obtain an opinion of outside counsel, substantially to the effect that, for U.S. federal income tax purposes, the spin-off and certain related transactions will qualify under Sections 355 and 368 of the Code. The opinion will rely on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion will not be binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

A substantial or extended decline in liquid hydrocarbon or natural gas prices, or in refining and wholesale marketing gross margins, would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

Prices for liquid hydrocarbons and natural gas and refining and wholesale marketing gross margins fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our liquid hydrocarbons and natural gas and the margins we realize on our refined products. Historically, the markets for liquid hydrocarbons, natural gas and refined products have been volatile and may continue to be volatile in the future. Many of the factors influencing prices of liquid hydrocarbons and natural gas and refining and wholesale marketing gross margins are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for liquid hydrocarbons, natural gas and refined products;
- the cost of exploring for, developing and producing liquid hydrocarbons and natural gas;
- the cost of crude oil to be manufactured into refined products;
- utilization rates of refineries;

- natural gas and electricity supply costs incurred by refineries;
- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") to agree to and maintain production controls;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornados;
- the price and availability of alternative and competing forms of energy;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of liquid hydrocarbons and natural gas, as well as on refining and wholesale marketing gross margins, are uncertain.

Lower liquid hydrocarbon and natural gas prices, may cause us to reduce the amount of these commodities that we produce, which may reduce our revenues, operating income and cash flows. Significant reductions in liquid hydrocarbon and natural gas prices or refining and wholesale marketing gross margins could require us to reduce our capital expenditures or impair the carrying value of our assets.

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

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

Estimates of liquid hydrocarbon, natural gas and synthetic crude oil reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The proved reserve information included in this report has been derived from engineering estimates. Estimates of liquid hydrocarbon and natural gas reserves were prepared by our in-house teams of reservoir engineers and geoscience professionals and were reviewed, on a selected basis, by our Corporate Reserves Group or third-party consultants. The synthetic crude oil reserves estimates were prepared by GLJ Petroleum Consultants, a third-party consulting firm experienced in working with oil sands. Reserves were priced at the unweighted average of closing prices for the first day of each month in the 12-month period ended December 31, 2010, as well as other conditions in existence at the date. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of liquid hydrocarbons, natural gas and bitumen that cannot be directly measured. (Bitumen is mined then upgraded into synthetic crude oil.) Estimates of economically producible reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other comparable producing areas;
- volumes of bitumen in-place and various factors affecting the recoverability of bitumen and its conversion into synthetic crude oil such as historical upgrader performance;
- the assumed effects of regulation by governmental agencies;
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs, and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves reflected in this report should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are based on an unweighted average of closing prices for the first day of each month in the 12-month period ended December 31, 2009, and costs applicable at the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor required by the applicable rules of the SEC to be used to calculate discounted future net revenues for reporting purposes is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future liquid hydrocarbon and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from liquid hydrocarbon and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance, identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as liquid hydrocarbons and natural gas are produced. Accordingly, to the extent we are not successful in replacing the liquid hydrocarbons and natural gas we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce liquid hydrocarbons and natural gas in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and on budget;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

The availability of crude oil and increases in crude oil prices may reduce our refining, marketing and transportation profitability and refining and wholesale marketing gross margins.

The profitability of our refining, marketing and transportation operations depends largely on the margin between the cost of crude oil and other feedstocks that we refine and the selling prices we obtain for refined products. We are a net purchaser of crude oil. A significant portion of our crude oil is purchased from various foreign national oil companies, producing companies and trading companies, including suppliers from the Middle East. These purchases are subject to political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located in that area of the world. Our overall refining, marketing and transportation profitability could be adversely affected by the availability of supply and rising crude oil and other feedstock prices which we do not recover in the marketplace. Refining and wholesale marketing gross margins historically have been volatile and vary with the level of economic activity in the various marketing areas, the regulatory climate, logistical capabilities and the available supply of refined products.

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

Although the deepwater drilling moratorium imposed by the U.S. Department of the Interior suspending outer continental shelf subsea and floating facility operations was lifted on October 12, 2010, we cannot predict when necessary plans and permits will be approved for renewed offshore drilling activity other than completions, interventions and workovers. An extended regulatory delay on other deepwater drilling activities in the Gulf of Mexico or changes in laws or regulations affecting our operations in these areas could have a material adverse effect on our business, financial condition, results of operations, cash flow and market value of our securities. In addition, other countries where we do business may make changes to their laws or regulations governing offshore operations, including deepwater areas that could have a similar material adverse effect.

We may 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 business, financial condition, results of operation and cash flow could be materially and adversely affected.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment, waste management, pollution prevention, greenhouse gas emissions, and characteristics and composition of gasoline and diesel fuels, as well as laws and regulations relating to public and employee safety and health and to facility security. We have incurred and may continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent 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. The specific impact of these laws and regulations may vary depending on a number of factors, including the age and location of operating facilities, marketing areas, crude oil and feedstock sources, and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site cleanups or curtail operations that could materially and adversely affect business, financial condition, results of operation and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws or regulations could result in civil penalties or criminal fines and other enforcement actions against us.

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. Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in countries where we operate: the United States, Canada, European Union ("EU") and Norway. Our operations result in these greenhouse gas emissions and emissions also arise from the use of our refined petroleum products by our customers. Through 2010, these included proposed federal legislation and state actions to develop statewide or regional programs, each of which could impose reductions in greenhouse gas emissions. These actions could result in increased: (1) costs to operate and maintain our facilities, (2) capital expenditures to install new emission controls at our refineries and other facilities, and (3) costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs or to produce fuels to meet low-carbon fuel standards. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for the products we sell, reduce the supply of crude oils which can be used and create delays in our obtaining air pollution permits for new or modified facilities. Legislation or regulatory activity that impacts or could impact our operations includes:

- EPA issued a finding that greenhouse gases contribute to air pollution that endangers public health and welfare. In April of 2010, the EPA finalized a greenhouse gas emission standard for mobile sources (cars and light duty vehicles). The endangerment finding, along with the mobile source standard, and EPA's determination that greenhouse gases are subject to regulation under the CAA, will lead to widespread regulation of stationary sources of greenhouse gas emissions. As a result, the EPA has issued a so-called tailoring rule to limit the applicability of the EPA's major permitting programs to larger sources of greenhouse gas emissions, such as our refineries and a few large production facilities. Although legal challenges have been filed against these EPA actions, no court decisions are expected for another year or more and the EPA permitting requirements will apply to our larger facilities starting in January 2011. EPA has also announced its plan to develop refining sector new source performance standards for greenhouse gas emissions with standards to be proposed in December 2011 and final standards to be adopted in December 2012.
- In the U.S., the House of Representatives and the Senate each had their own form of cap-and-trade legislation to reduce carbon emissions in the Congressional session ending in 2010. The House approved the Waxman-Markey Bill in 2009 and the Senate considered but did not approve any such legislation. Similar legislation may be introduced in 2011 in the new Congressional session or the legislation may seek to limit or delay implementation of the EPA greenhouse gas emission requirements. Among other actions, cap and trade systems require businesses that emit greenhouse gases to buy emission credits from the government, other businesses, or through an auction process.
- Although not ratified in the United States, the Kyoto Protocol, effective in 2005, has been ratified by countries in which we have or in the future may have operations.
- The non-binding Copenhagen Accord was reached in 2009 with the United States pledging to reduce emissions 17 percent below 2005 levels by 2020.

- The Canadian federal government has not enacted greenhouse gas emission reduction legislation although in signing the Copenhagen Accord, reaffirmed its commitment to reduce the country's emissions 17 percent from 2005 levels by 2020. Alberta enacted legislation effective in 2007 which requires large emission sources such as oil sands facilities to reduce their net emissions intensity by 12 percent as measured against their baseline emissions. Sources may also comply by making a compliance obligation payment or by purchasing verifiable offsets.
- The European Union Emissions Trading Scheme ("EU ETS") is in its second phase which runs from 2008 to 2012, in which EU member governments provide a certain number of free allowances to facilities and a facility may purchase additional EU allowances from other facilities, traders and the government. For, 2010, our EU facilities have complied with the EU ETS by using the allocated free allowances. Norway, as a member of the European Economic Area, while not in the European Union, has a carbon tax and also participates in the EU ETS. For 2010, our Norway facilities complied with the EU ETS by purchasing carbon allowances in the market.
- The Canadian federal government and province of Alberta jointly announced their intent to partially fund the AOSP's Quest Carbon Capture and Storage ("Quest CCS") project. Under the terms of their letters of intent, Alberta would contribute 745 million Canadian dollars and the Government of Canada would provide 120 million Canadian dollars toward the project's development. The Quest project would store approximately 1.1 million tons of carbon dioxide annually and should allow the AOSP to meet Canadian and Alberta emission reduction requirements for the foreseeable future. The operator intends to finalize the government funding agreements in the first quarter of 2011. A final investment decision on the Quest CCS project will be made at a later date, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as the agreement of joint venture partners.
- The State of California enacted legislation effective in 2007 capping California's greenhouse gas emissions at 1990 levels by 2020 and is implementing this legislation through a low-carbon fuel standard and a cap-and-trade program. The low-carbon fuel standard is being challenged in court. New Mexico has adopted a regulation which would reduce greenhouse gas emissions from current levels by three percent annually starting in 2012. We have not conducted significant business in California in recent years and discontinued operations in New Mexico in 2009, but other states where we have operations could adopt similar greenhouse gas limitations.

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, the EPA 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. Private party litigation has also been brought against emitters of greenhouse gas emissions, but we have not been named in those cases.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and /or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects. If we were unable to make up the delays associated with such factors or to recover the related costs, or if market conditions change, it could materially and adversely affect our business, financial conditions, results of operations and cash flows.

Many of our major projects and operations are conducted with partners, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such oil and gas exploration and production, oil sands mining or pipeline transportation, with partners in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. This could affect our operational performance, financial position and reputation.

Financial market uncertainty could impact our ability to obtain future financing.

In the future we may require financing to grow our business. Financial institutions participate in our revolving credit facility and provide us with services including insurance, cash management, commercial letters of credit, derivative instruments, and short-term investments. A deterioration of the financial market conditions could significantly increase our costs associated with borrowing. Our liquidity and our ability to access the credit and/or capital markets could also be adversely affected by changes in the financial markets and the global economy.

Worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 67 percent of our liquid hydrocarbon and natural gas sales volumes in 2010 was derived from production outside the United States and 72 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2010, were located outside the United States. All of our synthetic crude oil production and proved reserves are located in Canada. In addition, a significant portion of the feedstock requirements for our refineries is satisfied through supplies originating in Saudi Arabia, Kuwait, Canada, Mexico and various other foreign countries. We are, therefore, subject to the political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located in, and supplies originating from, those areas. There are many risks associated with operations in countries and in global markets, such as Equatorial Guinea, Indonesia, Libya and the Iraqi Kurdistan Region, including

- changes in governmental policies relating to liquid hydrocarbon, natural gas, bitumen, synthetic crude oil or refined product pricing and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

In recent weeks, civil unrest, which began in Tunisia, has spread to other parts of North Africa and the Middle East. There have been demonstrations by protestors demanding regime changes in countries such as Egypt, Libya, Yemen and Bahrain. Some of these demonstrations have been violent particularly in Libya where we have operations. If such unrest continues to spread, conflicts could result in civil wars, regional conflicts, and regime changes resulting in governments that are hostile to the United States. These may have the following results, among others:

- Volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates and reduced demand for our products;
- Negative impact on the world crude oil supply if transportation avenues are disrupted;
- Security concerns leading to the prolonged evacuation of our personnel;
- Damage to, or the inability to access, production facilities or other operating assets;
- Inability of our service and equipment providers to deliver items necessary for us to conduct our operations; and
- Imposition of trade sanctions by the U.S. government on Libya.

Continued hostilities in the Middle East and the occurrence or threat of future terrorist attacks could adversely affect the economies of the United States and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for liquid hydrocarbons, natural gas and refined products. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of governments through tax and other legislation, executive order and commercial restrictions could reduce our operating profitability, both in the United States and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, labor disputes and accidents. Our oil sands mining operations are subject to business interruptions due to breakdown or failure of equipment or processes and unplanned events such as fires, earthquakes, explosions or other interruptions. In addition, our refining, marketing and transportation operations are subject to business interruptions due to scheduled refinery turnarounds and unplanned events such as explosions, fires, pipeline ruptures or other interruptions, crude oil or refined product spills, severe weather and labor disputes. These same risks can be applied to the third-parties which transport crude oil and refined products to, from and among facilities. A prolonged disruption in the ability of any pipeline or vessels to transport crude oil or refined products could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks, as well as hazards of marine operations, such as capsizing, collision, acts of piracy and damage or loss from severe weather conditions. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

Litigation by private plaintiffs or government officials could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, products liability, consumer credit or privacy laws, product pricing or antitrust laws or any other laws or regulations that apply to our operations. While an adverse outcome in most litigation matters would not be expected to be material to us, in some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. There has been a trend in recent years of litigation by attorneys general and other government officials seeking to recover civil damages from companies. We are defending litigation of that type and anticipate that we will be required to defend new litigation of that type in the future. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, refineries, pipeline systems and other important physical properties have been described by segment under Item 1. Business. Except for oil and gas producing properties, including oil sands mines, which generally are leased, or as otherwise stated, such properties are held in fee. The plants and facilities have been constructed or acquired over a period of years and vary in age and operating efficiency. At the date of acquisition of important properties, titles were examined and opinions of counsel obtained, but no title examination has been made specifically for the purpose of this document. The properties classified as owned in fee generally have been held for many years without any material unfavorably adjudicated claim.

Net liquid hydrocarbon, natural gas, and synthetic crude oil sales volumes, with net bitumen production volumes are set forth in Item 8. Financial Statements and Supplementary Data – Supplemental Statistics. Estimated net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are set forth in Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities – Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business – Reserves.

Item 3. Legal Proceedings

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Environmental Proceedings

U.S. EPA Litigation

In 2006, we and other oil and gas companies joined the State of Wyoming in filing a petition for review against the U.S. EPA in the U.S. District Court for the District of Wyoming. These actions seek a court order mandating the U.S. EPA to disapprove Montana's 2006 amended water quality standards, on grounds that the standards lack sound scientific justification, they are arbitrary and capricious, and were adopted contrary to law. The water quality amendments at issue could require more stringent discharge limits and have the potential to require certain Wyoming coal bed methane operations to perform more costly water treatment or inject produced water. Approval of these standards could delay or prevent obtaining permits needed to discharge produced water to streams flowing from Wyoming into Montana. In February 2008, the U.S. EPA approved Montana's 2006 regulations, and we amended our petition for review. The court stayed this case while the U.S. EPA mediated the matter between Montana, Wyoming and the Northern Cheyenne tribe. The mediation was unsuccessful; however the Court ultimately vacated the U.S. EPA's approval of the 2003 and 2006 Montana standards and remanded the matter to the U.S. EPA with instructions for reconsideration. The federal government filed a Notice of Appeal, but subsequently filed a voluntary Motion to dismiss which was granted by the District Court.

New Mexico Litigation

In December 2008, the State of New Mexico filed a state court suit against us alleging violations of the New Mexico Air Quality Control Act. The lawsuit arose out of a February 2008 notice of violation issued to our Indian Basin Natural Gas Plant. We believe there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. We have finalized a consent order and the court has approved it. The order required a cash penalty of $610,560 plus plant compliance projects and supplemental environmental projects estimated to cost over $5 million. We paid the cash penalty of $610,560 and entered into a Supplemental Consent Decree, approved by the court on July 30, 2010, pursuant to which we would pay $2.7 million as a civil penalty in lieu of one of the proposed supplemental environmental projects. All of these payments were made on August 11, 2010. Installation of the plant compliance projects was completed on November 15, 2010, by the current operator of the plant. We were the operator and part owner of the plant through June 2009. We are working with the other plant owners to obtain reimbursement for their share of these costs. The State of New Mexico has agreed the case should be dismissed and the consent decree terminated. A draft joint motion to the court has been prepared and was submitted to NMED for approval.

Powder River Basin Litigation

The U.S. Bureau of Land Management ("U.S. BLM") completed multi-year reviews of potential environmental impacts from coal bed methane development on federal lands in the Powder River Basin, including those in Wyoming. The U.S. BLM signed a Record of Decision ("ROD") on April 30, 2003, supporting increased coal bed methane development.

Plaintiff environmental and other groups filed suit in May 2003 in federal court against the U.S. BLM to stop coal bed methane development on federal lands in the Powder River Basin until the U.S. BLM conducted additional environmental impact studies. We intervened as a party in the ongoing litigation before the Wyoming Federal District Court. As these lawsuits to delay energy development in the Powder River Basin progressed through the courts, the U.S. BLM continued to process permits to drill under the ROD. During the last quarter of 2008, the Court ruled in U.S. BLM's favor, finding its environmental studies and stewardship were adequate and protective under federal law. Plaintiffs appealed this ruling to the 10th Circuit Court of Appeals, which affirmed the district court's decision on June 18, 2010. Plaintiffs did not seek certiorari from the Supreme Court of the United States in this matter. Thus, this matter is concluded.

Pipeline Enforcement Matters

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued a Notice of Probable Violation ("NOPV"), Proposed Civil Penalty, and Proposed Compliance Order to Marathon Pipe Line LLC ("MPL") related to the March 10, 2009 incident at St. James, Louisiana. PHMSA has proposed a civil penalty in the amount of approximately $1 million. PHMSA granted MPL extensions in which to respond to the Notice of Probable Violation. On January 25, 2011, MPL filed its request for a hearing in response to the NOPV.

Other Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2010, under federal and state environmental laws. Except as described herein, it is not possible to predict accurately the ultimate outcome of these matters; however, management's belief set forth in the first paragraph under Legal Proceedings above takes such matters into account.

Claims under CERCLA and related state acts have been raised with respect to the clean-up of various waste disposal and other sites. CERCLA is intended to facilitate the clean-up of hazardous substances without regard to fault. Potentially responsible parties ("PRPs") for each site include present and former owners and operators of, transporters to and generators of the substances at the site. Liability is strict and can be joint and several. Because of various factors including the difficulty of identifying the responsible parties for any particular site, the complexity of determining the relative liability among them, the uncertainty as to the most desirable remediation techniques and the amount of damages and clean-up costs and the time period during which such costs may be incurred, we are unable to reasonably estimate our ultimate cost of compliance with CERCLA.

The projections of spending for and/or timing of completion of specific projects provided in the following paragraphs are forward-looking statements. These forward-looking statements are based on certain assumptions including, but not limited to, the factors provided in the preceding paragraph. To the extent that these assumptions prove to be inaccurate, future spending for and/or timing of completion of environmental projects may differ materially from those stated in the forward-looking statements.

As of December 31, 2010, we had been identified as a PRP at a total of eight CERCLA waste sites. Based on currently available information, which is in many cases preliminary and incomplete, we believe that our liability for clean-up and remediation costs in connection with three of these sites will be under $100,000 and with one site will be under $200,000. As to two sites, we believe that our liability for clean-up and remediation costs will be under $1 million per site. As to the remaining two sites, we believe that our liability for clean-up and remediation costs will be under $4 million for one of the sites and over $5 million for the other site. In addition, there are four sites for which we have received information requests or other indications that we may be a PRP under CERCLA, but for which sufficient information is not presently available to confirm the existence of liability.

There are also 116 sites, excluding retail marketing outlets, where remediation is being sought under other environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, we believe that liability for clean-up and remediation costs in connection with five of these sites will be under $100,000 per site, that 57 sites have potential costs between $100,000 and $1 million per site and that 28 sites may involve remediation costs between $1 million and $5 million per site. Twelve sites have incurred remediation costs equal to or greater than $5 million per site. With respect to the remaining 14 sites, Ashland Inc ("Ashland") retains responsibility to us for remediation, subject to caps and other requirements contained in the agreements with Ashland related to the acquisition of Ashland's minority interest in Marathon Petroleum Company LP in 2005. We estimate that we will be responsible for $11.4 million in remediation costs at these sites which will not be reimbursed by Ashland, and we have included this amount in our accrued environmental remediation liabilities as of December 31, 2010.

There is one site that involves a remediation program in cooperation with the Michigan Department of Environmental Quality ("MDEQ") at a closed and dismantled refinery site located near Muskegon, Michigan. During the next 26 years, we anticipate spending approximately $5 million in remediation costs at this site. In 2011, interim remediation measures will continue to occur and appropriate site characterization and risk-based assessments nec essary for closure will be refined and may change the estimated future expenditures for this site. The closure strategy being developed for this site and ongoing work at the site are subject to approval by the MDEQ. Expenditures for remedial measures in 2010 and 2009 were $221,000 and $291,000, respectively, with expenditures for remedial measures in 2011 expected to be approximately $1.5 million.

We are subject to a pending enforcement matter with the Illinois Environmental Protection Agency and the Illinois Attorney General's Office since 2002 concerning self-reporting of possible emission exceedences and permitting issues related to storage tanks at the Robinson, Illinois refinery. There were no developments in this matter in 2010.

During 2001, we entered into a New Source Review consent decree and settlement of alleged 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 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"). Pursuant to a modification to our New Source Review consent decree, we have agreed with the U.S. Department of Justice and the 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 Clean Air Act violations relating to benzene waste NESHAPS. This modification was finalized as of June 30, 2010, and the civil penalty has been paid.

OSHA previously announced a National Emphasis Program to inspect most domestic oil refineries. The inspections began in 2007 and focused on compliance with the OSHA Process Safety Management requirements. OSHA or state-equivalent agencies have conducted inspections at our Canton, Robinson, Catlettsburg, Detroit and Texas City refineries with agreed–to penalties of $321,500 and $135,000 imposed in Canton and Texas City, respectively. No penalties were imposed as a result of the other inspections. An inspection occurred at Garyville in 2010, however no enforcement action by OSHA or equivalent state agency has resulted.

In January 2011, the U.S. EPA notified us of 18 alleged violations of various statutory and regulatory provisions related to motor fuels, some of which we had previously self-reported to the U.S. EPA. No formal enforcement action has been commenced and no demand for penalties has been asserted by the U.S. EPA in connection with these alleged violations. However, it is possible that U.S. EPA could seek penalties in excess of $100,000 in connection with one or more of the alleged violations.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The principal market on which Marathon common stock is traded is the New York Stock Exchange. As of January 31, 2011, there were 52,216 registered holders of Marathon common stock.

The following table reflects high and low sales prices for Marathon common stock and the related dividend per share by quarter for the past two years:

	2010			2009		
Dollars per share	High Price	Low Price	Dividends	High Price	Low Price	Dividends
Quarter 1	$ 32.85	$ 28.04	$ 0.24	$ 29.87	$ 20.92	$ 0.24
Quarter 2	34.11	30.19	0.25	33.41	27.08	0.24
Quarter 3	34.98	30.21	0.25	33.88	28.03	0.24
Quarter 4	37.03	33.07	0.25	35.27	30.48	0.24
Full Year	37.03	28.04	0.99	35.27	20.92	0.96

Dividends

Our Board of Directors intends to declare and pay dividends on Marathon common stock based on the financial condition and results of operations of Marathon Oil Corporation, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining the dividend policy with respect to Marathon common stock, the Board will rely on our consolidated financial statements of Marathon. Dividends on Marathon common stock are limited to our legally available funds.

Issuer Purchases of Equity Securities

The following table provides information about purchases by Marathon and its affiliated purchaser during the quarter ended December 31, 2010, of equity securities that are registered by Marathon pursuant to Section 12 of the Securities Exchange Act of 1934:

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [(c)]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [(c)]
10/01/10 – 10/31/10	1,530	$ 33.62	-	$ 2,080,366,711
11/01/10 – 11/30/10	23,382	$ 35.68	-	$ 2,080,366,711
12/01/10 – 12/31/10	43,505 [(b)]	$ 35.11	-	$ 2,080,366,711
Total	68,417	$ 35.27	-	

(a) 25,884 shares of restricted stock were delivered by employees to Marathon, upon vesting, to satisfy tax withholding requirements.

(b) 42,533 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon.

(c) 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 December 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.

Item 6. Selected Financial Data

(Dollars in millions, except as noted)	2010[(a)]	2009[(b)(c)]	2008[(b)(c)(d)]	2007[(b)(c)(e)(f)]	2006[(b)(c)(g)]
Statement of Income Data					
Revenues	$ 72,321	$ 53,287	$ 76,589	$ 63,845	$ 64,246
Income from continuing operations	2,568	1,184	3,384	3,766	4,787
Net income	2,568	1,463	3,528	3,956	5,234
Per Share Data					
Basic :					
Income from continuing operations	$ 3.62	$ 1.67	$ 4.77	$ 5.46	$ 6.69
Net income	$ 3.62	$ 2.06	$ 4.97	$ 5.73	$ 7.31
Diluted :					
Income from continuing operations	$ 3.61	$ 1.67	$ 4.75	$ 5.42	$ 6.63
Net income	$ 3.61	$ 2.06	$ 4.95	$ 5.69	$ 7.25
Statement of Cash Flows Data					
Additions to property, plant and equipment	$ 4,762	$ 6,231	$ 6,989	$ 3,757	$ 3,325
Dividends paid	704	679	681	637	547
Dividends per share	$ 0.99	$ 0.96	$ 0.96	$ 0.92	$ 0.76
Balance Sheet Data as of December 31:					
Total assets	$ 50,014	$ 47,052	$ 42,686	$ 42,746	$ 30,831
Total long-term debt, including capitalized leases	7,601	8,436	7,087	6,084	3,061

(a) Includes long-lived asset impairments of $479 million primarily related to E&P segment assets (see Item 8. Financial Statements and Supplementary Data—Note 15 to the consolidated financial statements).

(b) We have revised prior year amounts as discussed in Item 8. Financial Statements and Supplementary Data—Note 1 to the consolidated financial statements. Revenues were reduced by $183 million in 2009, $165 million in the 2008, $251 million in 2007 and $193 million in 2006; however, consolidated income did not change because an offsetting amount is in cost of revenues.

(c) Our businesses in Ireland and Gabon were sold in 2009. Previous periods have been recast to reflect these businesses in discontinued operations.

(d) Includes a $1,412 million impairment of goodwill related to the OSM reporting unit, (see Note 14 to the consolidated financial statements) and a $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing companies.

(e) On October 18, 2007, we completed the acquisition of all the outstanding shares of Western Oil Sands Inc.

(f) Effective May 1, 2007, we no longer consolidate EGHoldings and our investment in EGHoldings is accounted for under the equity method of accounting; therefore, EGHoldings' additions to property, plant and equipment subsequent to April 2007 are not included in our capital expenditures.

(g) Effective April 1, 2006, we changed our accounting for matching buy/sell transactions. This change had no effect on income from continuing operations or net income, but the revenues and cost of revenues recognized after April 1, 2006, are less than the amounts that would have been recognized under previous accounting practices.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

We are a global integrated energy company with significant operations in North America, 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, 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," "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Item 1. Business, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

Plan to Create Independent Downstream Company

On January 13, 2011, the Board of Directors of Marathon Oil Corporation ("Marathon") announced that it has approved moving forward with plans to spin off Marathon's downstream (Refining, Marketing and Transportation) business, creating two independent energy companies: Marathon Petroleum Corporation ("MPC") and Marathon Oil Corporation ("MRO"). To effect the spin-off, Marathon intends to distribute one share of MPC for every two shares of Marathon held at a record date to be determined. The transaction is expected to be effective June 30, 2011, with distribution of MPC shares shortly thereafter. A tax ruling request was submitted to the U.S. Internal Revenue Service ("IRS") regarding the tax-free nature of the spin-off and Marathon anticipates a response during the second quarter of 2011.

Overview – Market Conditions

Exploration and Production

Prevailing prices for the various grades 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 remained in the $75 to $85 per barrel range during much of 2010. Crude oil prices rose sharply through the first half of 2008 as a result of strong global demand, a declining dollar, ongoing concerns about supplies of crude oil, and geopolitical risk. Later in 2008, crude oil prices sharply declined as the U.S. dollar rebounded and global demand decreased as a result of economic recession. The price decrease continued into 2009, but reversed after dropping below $33.98 in February, ending the year 2009 at $79.36. The following table lists benchmark crude oil and natural gas price annual averages for the past three years.

Benchmark	2010	2009	2008
WTI crude oil *(Dollars per barrel)*	$ 79.61	$ 62.09	$ 99.75
Dated Brent crude oil *(Dollars per barrel)*	$ 79.50	$ 61.67	$ 97.26
Henry Hub natural gas *(Dollars per mcf)*[(a)]	$ 4.39	$ 3.99	$ 9.04

(a) First-of-month price index.

Our domestic crude oil production is about 73 percent sour. Sour crude contains more sulfur than light sweet WTI does. Sour crude oil also tends to be heavier than light sweet crude oil and sells at a discount to light sweet crude oil because of 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 benchmark. The differential between WTI and Dated Brent average prices narrowed to $0.11 in 2010 compared to $0.42 in 2009 and $2.49 in 2008.

Natural gas prices on average were higher in 2010 than in 2009, although below the high levels experienced in 2008. 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 regions are Europe and Equatorial Guinea, where our natural gas sales have been and, in the case of Equatorial Guinea primarily, still are subject to term contracts, making realized prices in these areas less volatile. The natural gas being sold from these regions, primarily Equatorial Guinea, are at fixed prices; therefore, our reported average natural gas realized prices may not fully track market price movements.

Oil Sands Mining

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

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

The table below shows average benchmark prices that impact both our revenues and variable costs.

Benchmark	2010	2009	2008
WTI crude oil *(Dollars per barrel)*	$ 79.61	$ 62.09	$ 99.75
Western Canadian Select *(Dollars per barrel)*[(a)]	$ 65.31	$ 52.13	$ 79.59
AECO natural gas sales index *(Dollars per mmbtu)*[(b)]	$ 3.89	$ 3.49	$ 7.74

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.
(b) Monthly average 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 west Africa, the U.S. and Europe.

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 2010 and 2009, the gross sales from the plant were 3.7 million and 3.9 million metric tonnes, while in 2008, its first full year of operations, the plant sold 3.4 million metric tonnes. World LNG trade in 2010 has been estimated to be 219 million metric tonnes, while worldwide capacity increased approximately 31 million metric tonnes in 2010 as new LNG supply projects began operation. LNG demand also increased as global economics bounced back from the economic crisis. Long-term LNG continues to be in demand as markets seek the benefits of clean burning natural gas. Market prices for LNG are not reported or posted. 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 AMPCO. Gross sales of methanol from the plant totaled 850,605, 960,374 and 792,794 metric tonnes in 2010, 2009 and 2008. 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. World demand for methanol in 2010 has been estimated to be 45 million metric tonnes. Our plant capacity of 1.1 million metric tonnes is about 3 percent of total 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") crude oil prices and a 6-3-2-1 ratio of products (6 barrels of crude oil producing 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 2010, the sweet/sour differential widened, due to a variety of worldwide economic and petroleum industry related factors, including higher hydrocarbon demand. The sweet/sour differential widening contributed to the increase in our 2010 refining and wholesale marketing gross margin compared to 2009. In 2009, the sweet/sour differential narrowed, due to a variety of worldwide economic and petroleum industry related factors, primarily related to lower hydrocarbon demand. Sour crude accounted for 54 percent, 50 percent and 52 percent of our crude oil processed in 2010, 2009 and 2008.

The following table lists calculated average crack spreads for the Midwest (Chicago) and Gulf Coast markets and the sweet/sour differential for the past three years.

(Dollars per barrel)	2010	2009	2008
Chicago LLS 6-3-2-1	$ 3.04	$ 3.52	$ 3.27
U.S. Gulf Coast LLS 6-3-2-1	$ 2.14	$ 2.54	$ 2.45
Sweet/Sour differential[a]	$ 7.71	$ 5.82	$ 11.99

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

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.

Manufacturing costs are primarily driven by the cost of energy used by our refineries and the level of maintenance costs. Planned major maintenance activities, or turnarounds, requiring temporary shutdown of certain refinery operating units, are periodically performed at each refinery. Planned turnaround and major maintenance activities were completed at our Garyville, Louisiana; Catlettsburg, Kentucky; Detroit, Michigan; Texas City, Texas and Robinson, Illinois refineries in 2010. This compares turnarounds and major maintenance activities that were completed at our Catlettsburg, Robinson and Garyville refineries in 2009 and at our Catlettsburg, Garyville, Robinson and Canton, Ohio, refineries in 2008.

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. After decreasing in 2008 and 2009, refined product demand for the U.S. increased in 2010 associated with the slow economic recovery. For our marketing area, we estimate a distillate demand increase of eight percent in 2010 while gasoline demand remained constant from 2009 levels. For 2009, gasoline demand declined about one percent and distillate demand declined about 12 percent from 2008 levels. The product margin that we can realize generally increases or decrease along with market demand for gasoline and distillates. The gross margin on merchandise sold at retail outlets has been historically less volatile.

2010 Highlights

E&P Segment

- Expanded opportunities in unconventional, liquids-rich U.S. resource plays: the Niobrara in southeast Wyoming and northern Colorado, Oklahoma's Anadarko Woodford Shale, the Eagle Ford Shale in south Texas and the Bakken Shale in western North Dakota.
- Acquired positions in four exploration blocks in the Iraqi Kurdistan Region.
- Continued Bakken Shale production ramp-up, added a sixth rig in the third quarter.
- Added ten onshore exploration licenses with shale gas potential in Poland for a total of 11 licenses.
- Continued successful exploration program in Libya with seven discoveries.
- Commenced production from the deepwater Gulf of Mexico Droshky development in Green Canyon Block 244.

OSM Segment

- Commenced start-up of the Canadian Jackpine Mine operations in the third quarter, with an ongoing phased start-up of the expanded upgrader operations.

Reserves

- Added net proved reserves, for the E&P and OSM segments combined, of 112 mmboe, excluding dispositions.

IG Segment

- Achieved operational availability of better than 97 percent at the Equatorial Guinea LNG facility during the year.

Refining, Marketing and Transportation Segment

- Completed full integration of refinery units added as part of the Garyville Major Expansion project and realized increased refining capacity.
- Progressed construction of the Detroit Heavy Oil Upgrading Project to approximately 50 percent as of year-end, with completion expected in the second half of 2012.
- Increased Speedway same store gasoline sales volumes and merchandise sales 3 percent and 4 percent respectively, compared to 2009.
- Speedway® named best gasoline brand in the nation in its category, by the 2010 EquiTrend® Brand Study, for the second consecutive year.

Divestitures

- Sold an undivided 20 percent outside-operated interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola in February 2010.
- Sold our St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 SuperAmerica retail outlets, plus related inventories in December 2010.

Consolidated Results of Operations: 2010 compared to 2009

Revenues are summarized in the following table:

(In millions)	2010	2009
E&P	$ 11,019	$ 7,949
OSM	920	723
IG	150	50
RM&T	62,487	45,530
Segment revenues	74,576	54,252
Elimination of intersegment revenues	(2,255)	(1,037)
Gain on U.K. natural gas contracts	-	72
Total revenues	$ 72,321	$ 53,287
Items included in both revenues and costs:		
Consumer excise taxes on petroleum products and merchandise	$ 5,208	$ 4,924

E&P segment revenues increased $3,070 million from 2009 to 2010, primarily due to higher average liquid hydrocarbon and natural gas realizations, slightly offset by lower liquid hydrocarbon and natural gas sales volumes. On average, our net worldwide liquid hydrocarbon realizations were 30 percent higher in 2010 than in 2009 and our net worldwide natural gas realizations were 13 percent higher. While liquid hydrocarbon sales volumes in 2010 benefited from the Droshky development in the Gulf of Mexico, which commenced production mid-year 2010, sales volumes were lower overall. The lower sales volumes in 2010 were primarily the result of a turnaround that was completed in the second quarter of 2010 at the production facilities in Equatorial Guinea, natural field declines and 2009 asset dispositions.

	2010	2009
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)[(a)]		
United States	70	64
Europe	92	92
Africa	83	87
Total International	175	179
Worldwide Continuing Operations	245	243
Discontinued Operations[(b)]	-	5
Worldwide	245	248
Natural Gas Sales (mmcfd)		
United States	364	373
Europe[(c)]	105	138
Africa	409	430
Total International	514	568
Worldwide Continuing Operations	878	941
Discontinued Operations[(b)]	-	17
Worldwide	878	958
Total Worldwide Sales (mboepd)		
Continuing Operations	391	400
Discontinued Operations[(b)]	-	7
Worldwide	391	407

		2010		2009
E&P Operating Statistics				
Average Realizations[d]				
Liquid Hydrocarbons (per bbl)				
United States	$	72.30	$	54.67
Europe		81.95		64.46
Africa		71.71		53.91
Total International		77.11		59.31
Worldwide Continuing Operations		75.73		58.09
Discontinued Operations[b]		-		56.47
Worldwide	$	75.73	$	58.06
Natural Gas (per mcf)				
United States	$	4.71	$	4.14
Europe		7.10		4.90
Africa		0.25		0.25
Total International		1.65		1.38
Worldwide Continuing Operations		2.91		2.47
Discontinued Operations[b]		-		8.54
Worldwide	$	2.91	$	2.58

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

(c) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd and 22 mmcfd in 2010 and 2009.

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

E&P segment revenues included derivative gains of $95 million and losses of $13 million in 2010 and 2009. Excluded from E&P segment revenues were gains of $72 million in 2009 related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments. These U.K contracts expired in September 2009.

OSM segment revenues increased $197 million from 2009 to 2010. Revenues were impacted by net gains of $25 million and $13 million in 2010 and 2009 on derivative instruments. Excluding the derivatives impact, the increase in revenue reflects the 26 percent increase in synthetic crude oil realizations. Synthetic crude oil sales volumes were lower in 2010 due to 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.

RM&T segment revenues increased $16,957 million from 2009 to 2010 due to relative price level changes and increased refined product sales volumes. The increase in sales volumes is primarily related to production from the Garyville, Louisiana refinery expansion. The table below shows the average annual refined product benchmark prices for our marketing area:

(Dollars per gallon)	2010	2009
Chicago Spot Unleaded regular gasoline	$2.09	$1.68
Chicago Spot Ultra-low sulfur diesel	$2.17	$1.66
U.S. Gulf Coast Spot Unleaded regular gasoline	$2.05	$1.64
U.S. Gulf Coast Spot Ultra-low sulfur diesel	$2.16	$1.66

Income from equity method investments increased $116 million in 2010 from 2009 primarily as the result of higher commodity prices on the earnings of many of our equity investees in 2010.

Net gain on disposal of assets in 2010 is related the pretax gain of $811 million on 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. In 2009, we sold our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas, plus sales of other oil and gas properties and retail stores.

Cost of revenues increased $16,357 million from 2009 to 2010. The increase was primarily in the RM&T segment resulting from higher acquisition costs of crude oil and increased crude oil volume, primarily associated with increased production from our Garyville refinery.

Depreciation, depletion and amortization increased $361 million in 2010 from 2009. The DD&A increase in the RM&T segment was related to the Garyville expansion being put into service at the end of 2009. In the E&P segment, the DD&A increase was primarily related to the higher sales volumes at a higher rate of DD&A per barrel on our domestic E&P assets.

Long-lived asset impairment in 2010 includes $423 million related to our Powder River Basin field in the first quarter, as well as smaller impairments to other E&P segment fields due to reductions in estimated reserves, reduced drilling expectations and declining natural gas prices. See Item 8. Financial Statements and Supplementary Data—Note 15 to the consolidated financial statements for further information about the impairments.

Provision for income taxes increased $297 million from 2009 to 2010 primarily due to the increase in pretax income. The effective rate, however, decreased from 66 percent in 2009 to 50 percent in 2010. The effective tax rate is influenced by the geographical mix of income and related tax expense. In 2009 more income was generated in high tax jurisdictions than in 2010. In addition, in 2009, it was determined that we may not be able to realize all recorded foreign tax benefits and therefore a valuation allowance was recorded against these benefits. See Item 8. Financial Statements and Supplementary Data—Note 10 to the consolidated financial statements.

Discontinued operations reflect the 2009 disposal of our E&P businesses in Ireland and Gabon and the historical results of those operations, net of tax, for all periods presented. See Item 8. Financial Statements and Supplementary Data—Note 6 to the consolidated financial statements.

Segment Results: 2010 compared to 2009

Segment income for 2010 and 2009 is summarized and reconciled to net income in the following table.

(In millions)	2010	2009
E&P		
United States	$ 250	$ 55
International	1,690	1,166
E&P segment	1,940	1,221
OSM	(50)	44
IG	142	90
RM&T	682	464
Segment income	2,714	1,819
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(180)	(422)
Foreign currency effects on tax balances	32	(319)
Gain on disposal of assets	407	114
Impairments[(a)]	(303)	(45)
Gain on U.K. natural gas contracts[(b)]	-	37
Deferred income taxes -tax legislation changes	(45)	-
Loss on early extinguishment of debt	(57)	-
Discontinued operations	-	279
Net income	$ 2,568	$ 1,463

(a) Impairments in 2010 include a $262 million impairment ($423 million pretax) of our Powder River Basin field, a $9 million ($15 million pretax) writeoff of the remaining contingent proceeds from the sale of the Corrib natural gas development, a $15 million after-tax impairment ($25 million pretax) related to our investments in gas technology, and a $17 million impairment ($28 million pretax) related to a plant that manufactures maleic anhydride. (See Item 8. Financial Statements and Supplementary Data—Note 15 to the consolidated financial statements.) Impairments in 2009 reflect a $45 million ($70 million pretax) writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development. (See Item 8. Financial Statements and Supplementary Data—Note 9 to the consolidated financial statements). Impairments in 2008 include the $1,412 million impairment of goodwill related to the OSM reporting unit (See Item 8. Financial Statements and Supplementary Data—Note 14 to the consolidated financial statements) and the $25 million impairment ($40 million pretax) related to our investments in ethanol producing companies.

(b) Amounts relate to natural gas contracts in the U. K. that are accounted for as derivative instruments and recorded at fair value.

United States E&P income increased $195 million from 2009 to 2010. The majority of the income increase was primarily due to higher liquid hydrocarbon and natural gas realizations in 2009, along with higher liquid hydrocarbon sales volumes, partially offset by higher DD&A and higher exploration and operating costs. Exploration expenses were $275 million for the year 2010, compared to $153 million for 2009, reflecting increased geological and geophysical spending focused on shale plays and exploration dry well expense, primarily in the Flying Dutchman well in the Gulf of Mexico.

International E&P income increased $524 million from 2009 to 2010. This increase was primarily related to higher liquid hydrocarbon and natural gas realizations, partially offset by higher exploration expenses and income taxes. Exploration expenses were $223 million for the full year 2010, compared to $154 million for 2009, reflecting higher dry well expense with dry wells in Indonesia, Norway and Equatorial Guinea.

OSM segment income decreased $94 million from 2009 to 2010. Cost increases in 2010 associated with the planned turnaround at the AOSP and the Jackpine Mine start-up were in excess of the revenue increase previously discussed. Results for 2010 included after-tax gains on crude oil derivative instruments of $19 million, while the impact of derivatives on the 2009 periods was not significant.

IG segment income increased $52 million from 2009 to 2010. The increase in income was primarily the result of higher realizations for LNG and methanol.

RM&T segment income increased $218 million from 2009 to 2010, as a result of the increase in our refining and wholesale marketing gross margin per gallon from 6.10 cents in 2009 to 7.06 cents in 2010. The gross margin increase is primarily a result of a 32 percent widening of the sweet/sour differential, thereby decreasing the relative cost of crude processed by our refineries. The widening of the sweet/sour differential resulted from a variety of worldwide economic and petroleum industry related factors.

Also contributing to the increase in segment income were increases in our crude throughputs. We averaged 1,173 mbpd of crude oil throughput in 2010 compared to 957 mbpd in 2009 and increased our sour crude throughput by approximately 4 percent. Total refinery throughputs averaged 1,335 mbpd in 2010 compared to 1,153 mbpd in 2009. These throughputs were higher in 2010 than in 2009 primarily due to the Garyville refinery expansion, slightly offset by the reduction caused by the sale of the St. Paul Park refinery effective December 1, 2010 These favorable impacts to segment income were partially offset by increased manufacturing costs incurred related to the additional units at the Garyville refinery.

Included in the refining and wholesale marketing gross margins were pretax derivative losses of $29 million in 2010 and $83 million in 2009. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

The following table includes certain key operating statistics for the RM&T segment for 2010 and 2009.

RM&T Operating Statistics	2010	2009
Refining and wholesale marketing gross margin *(Dollars per gallon)*[(a)]	$ 0.0706	$ 0.0610
Refined products sales volumes *(Thousands of barrels per day)*	1,585	1,378

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

Consolidated Results of Operations: 2009 compared to 2008

Revenues are summarized in the following table:

(In millions)	2009	2008
E&P	$ 7,949	$ 12,246
OSM	723	1,213
IG	50	93
RM&T	45,530	64,481
Segment revenues	54,252	78,033
Elimination of intersegment revenues	(1,037)	(1,662)
Gain on U.K. natural gas contracts	72	218
Total revenues	$ 53,287	$ 76,589
Items included in both revenues and costs:		
Consumer excise taxes on petroleum products and merchandise	$ 4,924	$ 5,065

E&P segment revenues decreased $4,297 million from 2008 to 2009, primarily due to lower average liquid hydrocarbon and natural gas realizations, partially offset by higher liquid hydrocarbon and natural gas sales volumes. On average, our net worldwide liquid hydrocarbon realizations were 35 percent lower in 2009 than in 2008 and our net worldwide natural gas realizations were 46 percent lower. Liquid hydrocarbon sales volumes in 2009 benefited from a full year production from both the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico, which commenced production mid-year 2008. Natural gas sales volumes from Equatorial Guinea increased almost 16 percent from 2008 to 2009, more than making up for decreased sales as a result of our property divestitures in the Permian Basin of the U.S., Ireland and Norway. Because the majority of the natural gas sales increase was fixed-price sales to the LNG production facility in Equatorial Guinea, our average international natural gas realizations decreased by more than the market in general. Our share of the income ultimately generated by the subsequent export of LNG produced by EGHoldings, as well as methanol produced by AMPCO, is reflected in our Integrated Gas segment as discussed below.

	2009	2008
E&P Operating Statistics		
Net Liquid Hydrocarbon Sales (mbpd)[(a)]		
United States	64	63
Europe	92	55
Africa	87	87
Total International	179	142
Worldwide Continuing Operations	243	205
Discontinued Operations[(b)]	5	6
Worldwide	248	211
Natural Gas Sales (mmcfd)		
United States	373	448
Europe[(c)]	138	161
Africa	430	370
Total International	568	531
Worldwide Continuing Operations	941	979
Discontinued Operations[(b)]	17	37
Worldwide	958	1,016
Total Worldwide Sales (mboepd)		
Continuing Operations	400	369
Discontinued Operations[(b)]	7	12
Worldwide	407	381

	2009	2008
E&P Operating Statistics		
Average Realizations[(d)]		
Liquid Hydrocarbons (per bbl)		
United States	$ 54.67	$ 86.68
Europe	64.46	90.60
Africa	53.91	89.85
Total International	59.31	90.14
Worldwide Continuing Operations	58.09	89.07
Discontinued Operations[(b)]	56.47	96.41
Worldwide	$ 58.06	$ 89.29
Natural Gas (per mcf)		
United States	$ 4.14	$ 7.01
Europe	4.90	7.67
Africa	0.25	0.25
Total International	1.38	2.50
Worldwide Continuing Operations	2.47	4.56
Discontinued Operations[(b)]	8.54	9.62
Worldwide	$ 2.58	$ 4.75

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

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

(c) Includes natural gas acquired for injection and subsequent resale of 22 mmcfd and 32 mmcfd in 2009 and 2008.

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

E&P segment revenues included derivative losses of $13 million in 2009 and gains of $22 million in 2008. Excluded from E&P segment revenues were gains of $72 million in 2009 and $218 million in 2008 related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments. These U.K contracts expired in September 2009.

OSM segment revenues decreased $490 million from 2008 to 2009. Revenues were impacted by net gains of $13 million in 2009 and $48 million in 2008 on derivative instruments, which expired December 2009. Excluding the derivatives, the decrease in revenue reflects the almost 40 percent decline in synthetic crude oil realizations. Synthetic crude oil sales volumes were consistent between the years.

RM&T segment revenues decreased $18,951 million from 2008 to 2009 matching relative price level changes. While our overall refined product sales volumes in 2009 were relatively unchanged compared to 2008, the level of average petroleum prices declined significantly as shown in Item 1. Business—Refining, Marketing and Transportation. The level of crude oil prices has a direct influence on our refined product prices. The table below shows the average annual refined product benchmark prices for our marketing area.

(Dollars per gallon)	2009	2008
Chicago Spot Unleaded regular gasoline	$ 1.68	$ 2.50
Chicago Spot Ultra-low sulfur diesel	$ 1.66	$ 2.95
U.S. Gulf Coast Spot Unleaded regular gasoline	$ 1.64	$ 2.48
U.S. Gulf Coast Spot Ultra-low sulfur diesel	$ 1.66	$ 2.93

Sales to related parties decreased in 2009 as a result of the sale of our interest in Pilot Travel Centers LLC ("PTC") during the fourth quarter of 2008.

Income from equity method investments decreased $467 million in 2009 from 2008 primarily as the result of lower commodity prices on the earnings of many of our equity investees in 2009 and the sale of our equity method investment in PTC during the fourth quarter of 2008.

Net gain on disposal of assets in 2009 includes our gain on the sale of our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas, plus sales of other oil and gas properties and retail stores. In 2008, we sold our outside-operated interests (24 percent of Heimdal field, 47 percent of Vale field and 20 percent of Skirne field) and associated undeveloped acreage in offshore Norway and our share of the PTC joint venture in 2008.

Cost of revenues decreased $19,135 million from 2008 to 2009. The largest decreases were in the RM&T segment and resulted from lower acquisition costs of crude oil. Acquisition costs for refinery charge and blendstocks and for purchased refined products also decreased. In our other segments, lower commodity prices and the related lower energy costs also contributed to the lower cost of revenues.

Depreciation, depletion and amortization increased $496 million in 2009 from 2008. The increase in 2009 primarily relates to higher sales volumes, particularly from the Alvheim/Vilje development offshore Norway and the Neptune development in the Gulf of Mexico, both of which commenced production mid-year 2008.

Goodwill impairment expense of $1,412 million in 2008 relates to our OSM reporting unit. There were no such impairments in 2009. See Item 8. Financial Statements and Supplementary Data—Note 14 to the consolidated financial statements for further information about the impairment.

Net interest and other financial costs increased $121 million from 2008 to 2009. Interest income decreased due to substantially lower interest rates, although average cash balances were higher in 2009. While interest expense increased due to the February 2009 issuance of $1.5 billion in senior notes, increased capitalized interest related to our capital projects offset the impact. We recorded a writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development in the fourth quarter of 2009 by $70 million on the basis of new public information regarding the pipeline that would transport gas from the Corrib development.

Provision for income taxes decreased $1,110 million from 2008 to 2009 primarily due to the reduction in pretax income. The effective rate, however, increased from 50 percent in 2008 to 66 percent in 2009. The effective tax rate is influenced by the geographical mix of income and related tax expense. In 2009 more income was generated in high tax jurisdictions than in 2008. Also contributing to the increase in the effective tax rate is the remeasurement of foreign currency denominated tax balances to U.S. dollars. In 2009 the remeasurement provided a $319 million tax charge compared to a $249 million tax benefit in 2008. See Item 8. Financial Statements and Supplementary Data—Note 10 to the consolidated financial statements.

Discontinued operations reflect the current year disposal of our E&P businesses in Ireland and Gabon and the historical results of those operations, net of tax, for all periods presented. See Item 8. Financial Statements and Supplementary Data—Note 6 to the consolidated financial statements.

Segment Results: 2009 compared to 2008

Segment income for 2009 and 2008 is summarized and reconciled to net income in the following table.

(In millions)	2009	2008
E&P		
United States	$ 55	$ 869
International	1,166	1,687
E&P segment	1,221	2,556
OSM	44	258
IG	90	302
RM&T	464	1,179
Segment income	1,819	4,295
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(422)	(75)
Foreign currency effects on tax balances	(319)	249
Impairments[(a)]	(45)	(1,437)
Gain on U.K. natural gas contracts[(b)]	37	111
Gain on disposal of assets	114	241
Discontinued operations	279	144
Net income	$ 1,463	$ 3,528

(a) Impairments in 2009 reflect $45 million ($70 million pretax) writeoff of a portion of the contingent proceeds from the sale of the Corrib natural gas development (See Item 8. Financial Statements and Supplementary Data—Note 9 to the consolidated financial statements) that was recorded the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. Impairments in 2008 include a $1,412 million impairment of goodwill related to the OSM reporting unit (See Item 8. Financial Statements and Supplementary Data—Note Note 14 to the consolidated financial statements) and a $25 million after-tax impairment ($40 million pretax) related to our investments in ethanol producing facilities.

(b) Amounts relate to natural gas contracts in the U. K. that are accounted for as derivative instruments and recorded at fair value.

United States E&P income decreased $814 million, or 94 percent, from 2008 to 2009. The majority of the income decrease was due to liquid hydrocarbon and natural gas realizations averaging almost 40 percent lower than in 2008, as well as lower natural gas sales volumes and higher DD&A, partially offset by lower operating costs and exploration expenses. Exploration expenses were $153 million for the year 2009, compared to $238 million for 2008, reflecting decreased geological and geophysical spending and lower exploration dry well expense.

International E&P income decreased $521 million, or 31 percent, from 2008 to 2009. The majority of the income decrease is tied to lower liquid hydrocarbon and natural gas realizations and overall higher DD&A, primarily associated with a full year of Alvheim production. The revenue impact of lower realizations was partially offset by improved sales volumes from Norway and Equatorial Guinea. Additionally, operating costs and exploration expenses were lower. Exploration expenses were $154 million for the full year 2009, compared to $251 million for 2008, reflecting lower dry well expense and decreased geological and geophysical spending.

OSM segment income decreased $214 million, or 83 percent, from 2008 to 2009. The majority of the decrease in income for 2009 was due to synthetic crude oil realizations averaging almost 40 percent lower than in 2008, partially offset by lower blendstock and energy costs. Results for 2008 included after-tax gains on crude oil derivative instruments of $32 million, while the impact of derivatives on the 2009 periods was not significant. Those derivative instruments expired December 2009 (see Item 7A. Quantitative and Qualitative Disclosures about Market Risk).

IG segment income decreased $212 million, or 70 percent, from 2008 to 2009. The decrease in income was primarily the result of lower realizations for LNG and methanol. As evidenced by higher sales volumes, strong operational reliability at the EG LNG facility throughout 2009 partially offset the impact of lower prices. The LNG production facility averaged higher than 95 percent operational availability during 2009. We hold a 60 percent interest in the facility.

RM&T segment income decreased $715 million, or 61 percent, from 2008 to 2009, primarily as a result of the decrease in our refining and wholesale marketing gross margin per gallon from 11.66 cents in 2008 to 6.10 cents in 2009. The gross margin decline is a result of a 52 percent narrowing of the sweet/sour differential, thereby increasing the relative cost of crude processed by our refineries. The narrowing of the sweet/sour differential resulted from a variety of worldwide economic and petroleum industry related factors primarily related to lower hydrocarbon demand.

Included in the refining and wholesale marketing gross margins were pretax derivative losses of $83 million in 2009 and $87 million in 2008. For a more complete explanation of our strategies to manage market risk related to commodity prices, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We averaged 957 mbpd of crude oil throughput in 2009 and 944 mbpd in 2008. Total refinery throughputs averaged 1,153 mbpd in 2009 compared to 1,151 mbpd in 2008. Crude and total throughputs were lower in 2008 than in 2009 in part due to the impact that hurricanes and other weather related events had on our operations in 2008.

The following table includes certain key operating statistics for the RM&T segment for 2009 and 2008.

RM&T Operating Statistics	2009	2008
Refining and wholesale marketing gross margin *(Dollars per gallon)*[(a)]	$ 0.0610	$ 0.1166
Refined products sales volumes *(Thousands of barrels per day)*	1,378	1,352

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

Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Cash Flows

Net cash provided from operating activities totaled $5,873 million in 2010 compared to $5,268 million in 2009 and $6,752 million in 2008. The $605 million increase in 2010 reflects the impact of higher average realized prices in 2010. The $1,484 million decrease in 2009 primarily reflects the impact of lower average realized prices in 2009.

Net cash used in investing activities totaled $2,621 million in 2010, compared with $5,238 million in 2009 and $5,405 million in 2008. Significant investing activities include additions to property, plant and equipment and asset disposals.

The most significant additions to property, plant and equipment relate to our long-term projects, which cross several years. In our E&P segment, exploration and development projects in Angola impacted all three years. Development and completion of the Alvheim/Vilje project affected 2008, with other developments in the area in 2009 and 2010. Beginning in 2008, spending on U.S. exploration and development projects in the Gulf of Mexico and unconventional resource plays became a more significant portion of our additions to property, plant and equipment. In the OSM segment, the AOSP Expansion 1 began in 2008 and continued through most 2010. In our RM&T segment, the expansion of our Garyville, Louisiana, refinery affected 2008 and 2009. Also in RM&T, the expansion and upgrading of our Detroit, Michigan refinery commenced in 2007 with front-end engineering and design work and construction in 2008 through 2010.

Disposal of assets totaled $2,131 million, $865 million and $999 million in 2010, 2009 and 2008. In 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 for $1.3 billion. Additionally, our RM&T segment's assets in Minnesota were sold in December 2010. In 2009, we sold all of our operated and outside-operated interests in Ireland and Gabon, reporting the disposals as discontinued operations. We also sold our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas. In 2008, disposal of assets included proceeds from the sale of our outside-operated interests and related undeveloped acreage in Norway and our share of PTC. See Note 6 to the consolidated financial statements for more information about dispositions.

Net cash used in financing activities totaled $1,358 million in 2010, compared with cash provided from financing activities of $724 million in 2009 and cash used in financing activities of $1,193 million in 2008. In 2010, $500 million aggregate principal value of debt was repaid at a weighted average price of 117 percent of face value under two tender offers. Sources of cash included the issuance of $1.5 billion in senior notes in 2009, the issuance of $1.0 billion in senior notes in 2008. Repayments of debt and common stock repurchases under our share repurchase plan were significant uses of cash in 2008, while dividend payments impacted every year.

Liquidity and Capital Resources

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

2011 Activities on Plan to Create Independent Downstream Company

On February 1, 2011, MPC, currently a wholly owned subsidiary of Marathon, completed a private placement of three series of Senior Notes aggregating $3 billion (the "Notes"). The Notes are intended to establish a minimum $750 million initial cash balance for MPC upon the planned spin off of Marathon's downstream business. All cash above that level will be used to repay existing intercompany debt with Marathon, and any remaining proceeds will be distributed to Marathon on or before June 30, 2011. The Notes are unsecured and unsubordinated obligations of MPC which are guaranteed by Marathon on a senior unsecured basis. Marathon's guarantees will terminate upon completion of the spin-off.

On January 27, 2011, Marathon commenced cash tender offers for certain specified series of outstanding debt, including that of its wholly owned subsidiary, Marathon Oil Canada Corporation (formerly known as Western Oil Sands Inc.). The tender offers are for any and all of four series of outstanding notes and a maximum of $500 million in aggregate principal amount of three additional series of Marathon's outstanding notes. In the any and all offer, $1.2 billion in aggregate principal amount of notes was tendered and accepted with a settlement date of February 10, 2011. In the maximum tender offer, $1.2 billion in aggregate principal amount of notes was tendered, of which $500 million was accepted, and settled on February 25, 2011.

In February 2011, Marathon gave notice in accordance with the make whole call provisions of the respective indentures that we will redeem $798 million in addition to the $1.2 billion any and all offer and the $500 million maximum tender offer, for a total principal amount of $2.5 billion to be redeemed by the end of the first quarter of 2011.

See Item 8. Financial Statements and Supplementary Data—Note 25 to the consolidated financial statements for more information about these transactions.

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2010, we had $7,896 million in long term debt outstanding, $295 million of which is due within one year. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

At December 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.

Shelf Registration

During the third quarter of 2010, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 14 percent and 23 percent at December 31, 2010 and 2009. This includes $235 million of debt at December 31, 2010 that is serviced by United States Steel Corporation ("United States Steel").

(Dollars in millions)	2010	2009
Long-term debt due within one year	$ 295	$ 96
Long-term debt	7,601	8,436
Total debt	$ 7,896	$ 8,532
Cash	$ 3,951	$ 2,057
Equity	$ 23,771	$ 21,910
Calculation:		
Total debt	$ 7,896	$ 8,532
Minus cash	3,951	2,057
Total debt minus cash	3,945	6,475
Total debt	7,896	8,532
Plus equity	23,771	21,910
Minus cash	3,951	2,057
Total debt plus equity minus cash	$ 27,716	$ 28,385
Cash-adjusted debt-to-capital ratio	14%	23%

Capital Requirements

Capital Spending

We have approved a capital, investment and exploration budget of $5,267 million for 2011, which represents a 9 percent increase from our 2010 spending. Additional details related to the 2011 budget are discussed in Outlook.

Other Expected Cash Outflows

We plan to make contributions of up to $156 million to fund pension plans during 2011. As of December 31, 2010, $295 million of our long-term debt is due in the next twelve months, with $216 million of such amount related to the USX Separation. See 3 to the consolidated financials for a discussion of the USX Separation.

In December 2010, we entered into an agreement with an operator in the Eagle Ford shale, a liquids-rich play in Texas. We initially paid $10 million and will drill and complete four wells to earn approximately 17,000 net acres. We also have an option that expires October 31, 2011 to purchase the operator's remaining 58,000 net acres at a total cost of approximately $209 million, including the initial payment, carried well interest and lease extensions. In the event that we do not exercise the purchase option, the operator has the option to put the remaining 58,000 acres to us at a total cost, including the initial payment, carried well interest and lease extensions, of approximately $92 million.

Dividends of $0.98 per common share or $704 million were paid during 2010. On January 31, 2011, we announced that our Board of Directors had declared a dividend of $0.25 cents per share on Marathon common stock, payable March 10, 2011, to stockholders of record at the close of business on February 16, 2011.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 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 and cash from available borrowings.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The discussion of liquidity above also contains forward-looking statements regarding expected capital, investment and exploration spending and a review of our portfolio of assets. The forward-looking statements about our capital, investment and exploration budget 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 include prices of and demand for liquid hydrocarbons, natural gas and refined products, actions of competitors, disruptions or interruptions of our production, oil sands mining and bitumen upgrading or refining operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations. The forward-looking statements about our common share repurchase program are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially are changes in prices of and demand for crude oil, natural gas and refined products, actions of competitors, disruptions or interruptions of our production or refining operations due to unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Contractual Cash Obligations

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

(In millions)	Total	2011	2012-2013	2014-2015	Later Years
Long-term debt (excludes interest)[(a)] [(b)]	$ 7,527	$ 266	$ 1,624	$ 836	$ 4,801
Capital lease obligations[(a)]	660	47	102	89	422
Operating lease obligations[(a)]	976	148	299	254	275
Purchase obligations:					
Crude oil, feedstock, refined product and ethanol contracts[(c)]	8,623	7,439	876	259	49
Transportation and related contracts	1,920	393	327	226	974
Contracts to acquire property, plant and equipment	2,650	1,713	500	397	40
LNG terminal operating costs[(d)]	130	13	25	25	67
Service and materials contracts[(e)]	1,743	331	388	260	764
Unconditional purchase obligations[(f)]	40	8	16	16	-
Commitments for oil and gas exploration (non-capital)[(g)]	30	22	2	1	5
Total purchase obligations	15,136	9,919	2,134	1,184	1,899
Other long-term liabilities reported in the consolidated balance sheet[(h)]	2,757	242	863	717	935
Total contractual cash obligations[(i)] [(j)]	$ 27,056	$ 10,622	$ 5,022	$ 3,080	$ 8,332

(a) Upon the USX Separation, United States Steel assumed certain debt and lease obligations, including $198 million of long-term debt obligations related to industrial revenue bonds. The Financial Matters Agreement provides that, on or before the tenth anniversary of the USX Separation, United States Steel will provide for Marathon's discharge from any remaining liability under any of the assumed industrial revenue bonds. Such amounts are included in the above table because we remain primarily liable.

(b) We anticipate cash payments for interest of $452 million for 2011, $722 million for 2012-2013, $629 million for 2014-2015 and $3,274 million for the remaining years for a total of $5,079 million.

(c) The majority of these contractual obligations as of December 31, 2010 relate to contracts to be satisfied within the first 180 days of 2011. These contracts include variable price arrangements.

(d) 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.

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

(f) We are a party to a long-term transportation services agreement with Alliance Pipeline. This agreement was used by Alliance Pipeline to secure its financing. This arrangement represents an indirect guarantee of indebtedness. Therefore, this amount has also been disclosed as a guarantee.

(g) Commitments for 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.

(h) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2020. Also includes amounts for uncertain tax positions.

(i) Includes $239 million of contractual cash obligations that have been assumed by United States Steel. See Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Obligations Associated with the Separation of United States Steel.

(j) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,355 million. See Note 18 to the consolidated financial statements.

Transactions with Related Parties

We own a 63 percent working interest in the Alba field offshore Equatorial Guinea. Onshore Equatorial Guinea, we own a 52 percent interest in an LPG processing plant, a 60 percent interest in an LNG production facility and a 45 percent interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes. The methanol that is produced is then sold through another equity method investee.

Sales of refined petroleum products to our 50 percent equity method investee, PTC, which was sold in October 2008, accounted for 2.5 percent or less of our total sales revenue for 2008.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We have provided various guarantees related to equity method investees, United States Steel and others. These arrangements are described in Note 24 to the consolidated financial statements.

We will issue stand alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2010, 2009 and 2008 aggregated $439 million, $224 million and $1,111 million. Most of our letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to insure our payments for crude purchases, outstanding company debt and future abandonment liabilities.

In December 2010, we entered into an agreement with an operator in the Eagle Ford Shale play Texas. We initially paid $10 million and will drill and complete four wells to earn approximately 17,000 net acres. We also have an option that expires October 31, 2011 to purchase their remaining 58,000 net acres in the Eagle Ford Shale in these two counties at approximately $3,000 per acre, or a total of approximately $175 million. In the event that we do not exercise the purchase option, the operator has the option to put the remaining 58,000 acres to us at approximately $1,000 per acre, or a total of approximately $58 million.

Obligations Associated with the Separation of United States Steel

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

As of December 31, 2010, we have identified the following obligations that have been assumed by United States Steel:

- $198 million of industrial revenue bonds related to environmental improvement projects for current and former United States Steel facilities, with maturities ranging from 2011 through 2033. Accrued interest payable on these bonds was $4 million at December 31, 2010. The Financial Matters Agreement provides that, on or before December 31, 2011, the tenth anniversary of the USX Separation, Steel shall pay Marathon an amount equal to the principal amount of, all accrued and unpaid debt service then outstanding on, and any premium required to immediately retire each bond. Upon such payment, Marathon shall retire all then outstanding bonds.

- $20 million of sale-leaseback financing under a lease for equipment at United States Steel's Fairfield Works, with a term extending to 2012, subject to extensions. There was no accrued interest payable on this financing at December 31, 2010.
- $17 million of obligations under a lease for equipment at United States Steel's Clairton coke-making facility, with a term extending to 2012. There was no accrued interest payable on this financing at December 31, 2010.
- A guarantee with respect to all obligations of United States Steel to the limited partners of the Clairton 1314B Partnership, L.P., which was terminated on October 31, 2008. Upon termination of the partnership, we were not released from our obligations under guarantee. United States Steel has reported that it currently has no unpaid outstanding obligations to the limited partners. See Note 24 to the consolidated financial statements.
- Obligations of $239 million and corresponding receivables from United States Steel were recorded on our consolidated balance sheet as of December 31, 2010, (current portion - $220 million; long-term portion - $19 million).

In its Form 10-K for the year ended December 31, 2010, United States Steel management stated that it believes its liquidity will be adequate to satisfy its obligations for the foreseeable future. During the second quarter of 2010, United States Steel redeemed $89 million of certain industrial development and environmental improvement bonds for which we were liable.

Outlook

Our Board of Directors approved a capital, investment and exploration budget of $5,267 million for 2011, which includes budgeted capital expenditures of $4,837 million. This represents a 9 percent increase from 2010 spending. The focus of our 2011 budget is on exploration and production activities, with an emphasis on oil prospects and increasing our percentage of operated properties.

Exploration and Production

The worldwide exploration and production budget for 2011 is $3,417 million, a 29 percent increase over 2010 capital spending. The exploration and production strategy is based on three key elements: a solid portfolio of base assets, growth assets and impact exploration. The majority of the budget is allocated to projects that offer growth potential, with nearly $1 billion focused on three North America liquids resource plays: the Bakken shale play in North Dakota, the Eagle Ford shale play in Texas and the Anadarko Woodford shale play in Oklahoma. In the Bakken, we plan to drill 70 to 75 operated wells and 50 to 70 outside-operated wells. In the Anadarko Woodford shale, 20 to 25 operated wells and 25 to 50 outside-operated wells are planned. In the Eagle Ford shale, we plan to drill four operated wells. The remaining $900 million will be primarily for the advancement of the PSVM development on Block 31 offshore Angola and in-situ drilling in the Canadian oil sands.

Approximately $1 billion is budgeted for our base assets which include production operations in the Gulf of Mexico, Norway, Equatorial Guinea and other conventional liquid hydrocarbon operations worldwide. The focus of this spending is maintaining high levels of reliability and stable production primarily for conventional oil assets in Norway and the U.S.

Potentially high impact exploration projects receive 14 percent of the budget. Projects for impact exploration include conducting seismic surveys and drilling three to six wells on prospects in the deepwater Gulf of Mexico, Indonesia, the Iraqi Kurdistan Region and Poland.

The above discussion includes forward-looking statements with respect to anticipated future exploratory and development drilling, investments in new and existing resource plays and development projects. Some factors which 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, 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 or permits. The offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

The budget for Oil Sands Mining segment in 2011 is $294 million, less than half of 2010 spending. Our significant investment in this asset is reduced because Expansion 1 at the AOSP was completed in 2010 and continues to ramp up to full capacity through the first quarter of 2011.

Evaluation of the AOSP Quest Carbon Capture and Storage ("CCS") project continues. A final investment decision on the Quest CCS project will be made at a later date, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as a final joint venture partner agreement.

The above discussion includes forward-looking statements concerning the start-up of the expanded upgrader. Factors which could affect this project include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions and delays or other risks customarily associated with start-up projects.

Refining, Marketing and Transportation

The 2011 budget includes $1,238 million for RM&T segment projects, a 16 percent increase over 2010 spending. The Detroit refinery heavy oil upgrading and expansion project continues in 2011, accounting for about half of the budget. The Detroit project which is targeted for start-up in the second half of 2012, will increase the refinery's heavy oil, including Canadian bitumen blends, upgrading capacity by about 80 mbpd, and will increase its total crude oil refining capacity by approximately 15 mbpd.

The remainder of the budget is allocated across segment operations and to comply with the Mobile Source Air Toxics ("MSAT II") regulations that were effective January 1, 2011.

The above discussion includes forward-looking statements concerning the Detroit refinery heavy oil upgrading and expansion project and MSAT II regulations compliance costs. Some factors that could affect the Detroit and MSAT II projects include transportation logistics, availability of materials and labor, unforeseen hazards such as weather conditions, 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.

Corporate and Other

The remaining $308 million of our 2011 budget relates to capitalized interest and corporate activities.

The forward-looking statements about our capital, investment and exploration budget 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 include prices of and demand for crude oil, natural gas and refined products, actions of competitors, disruptions or interruptions of our production or refining operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Recent Events

In February 2011, civil unrest occurred in parts of North Africa, including Libya where we have exploration and production operations, and the Middle East. We believe that some of our production operations have been temporarily suspended. The future impacts of the unrest are not known at this time. Our current property, plant and equipment investment in Libya is approximately $760 million.

Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and may 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, crude oil and feedstock sources, production processes and whether it is also engaged in the petrochemical business or the marine transportation of crude oil and refined products.

Legislation and regulations pertaining to fuel specifications, climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flow, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers. For additional information see Item 1A. Risk Factors.

Our environmental expenditures[(a)] for each of the last three years were:

(In millions)	2010	2009	2008
Capital	$ 305	$ 399	$ 421
Compliance			
Operating and maintenance	429	373	379
Remediation[(b)]	21	29	26
Total	$ 755	$ 801	$ 826

(a) Amounts are determined based on American Petroleum Institute survey guidelines regarding the definition of environmental expenditures.

(b) These amounts include spending charged against remediation reserves, where permissible, but exclude non-cash provisions recorded for environmental remediation.

Our environmental capital expenditures accounted for seven percent of capital expenditures for continuing operations in 2010, seven percent in 2009 and six percent in 2008.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Our environmental capital expenditures are expected to be $407 million, or six percent, of capital expenditures in 2011. Predictions beyond 2011 can only be broad-based estimates, which have varied, and will continue to vary, due to the ongoing evolution of specific regulatory requirements, the possible imposition of more stringent requirements and the availability of new technologies, among other matters. Based on currently identified projects, we anticipate that environmental capital expenditures will be approximately $408 million in 2012; however, actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed.

Further, we estimate that we may spend approximately $650 million over a four-year period beginning in 2008 to comply with MSAT II regulations relating to benzene content in refined products. We have finalized our strategic approach to comply with MSAT II regulations and updated project cost estimates to comply with these requirements. Our actual MSAT II expenditures have totaled $522 million through December 31, 2010 and we expect to spend $100 million on MSAT II in 2011. The cost estimates are forward-looking statements and are subject to change as further work is completed in 2011.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business – Environmental Matters, Item 3. Legal Proceedings and Item 1A. Risk Factors.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

The estimation of quantities of net reserves is a highly technical process, which is based upon several underlying assumptions that are subject to change. Estimates of reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. Beginning December 31, 2009, reserve estimates are based upon an unweighted average of commodity prices in the prior 12-month period, using the closing prices on the first day of each month. In previous periods, reserve estimates were based upon prices at December 31. Neither of these prices should be expected to reflect future market conditions. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business.

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved liquid hydrocarbon, natural gas and synthetic crude oil reserves. The existence and the estimated amount of reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. Additionally, both the expected future cash flows to be generated by oil and gas producing properties used in testing such properties for impairment and the expected future taxable income available to realize deferred tax assets also rely, in part, on estimates of quantities of net reserves.

Depreciation and depletion of liquid hydrocarbon, natural gas and synthetic crude oil producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. Over the past three years, the impact on our depreciation and depletion rate due to revisions of previous reserve estimates has not been significant to either our E&P or our OSM segments. However, during 2009, the change to presenting oil sand mining reserves as synthetic crude oil under the SEC's revised regulations caused our reported revisions to previous estimates to be near 50 percent of the beginning of the year reserve estimate. This presentation change did not have a significant impact upon the calculation of depreciation, depletion and amortization for our OSM segment. For our E&P segment, on average, a five percent increase in the amount of proved liquid hydrocarbon and natural gas reserves would lower the depreciation and depletion rate by approximately $0.64 per barrel, which would increase pretax income by approximately $91 million annually, based on 2010 production. Conversely, on average, a five percent decrease in the amount of proved liquid hydrocarbon and natural gas reserves would increase the depreciation and depletion rate by approximately $0.70 per barrel and would result in a decrease in pretax income of approximately $100 million annually, based on 2010 production. For our OSM segment, on average, a five percent increase in estimated proved synthetic crude oil reserves would lower the depreciation and depletion rate by approximately $0.16 per barrel and would result in an increase in pretax income of approximately $3 million annually, based on 2010 production. On average, a five percent decrease in estimated proved synthetic crude oil reserves would increase the depreciation and depletion rate by approximately $0.36 per barrel and would result in a decrease in pretax income of approximately $6 million annually, based on 2010 production.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. We use a market or income approach for recurring fair value measurements and endeavor to use the best information available. See Item 8. Financial Statements and Supplementary Data—Note 15 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- assessment of impairment of long-lived assets;
- assessment of impairment of goodwill;
- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions, and
- recorded value of derivative instruments

Impairment Assessments of Long-Lived Assets and Goodwill

Fair value calculated for the purpose of testing our long-lived assets and goodwill for impairment is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- Future liquid hydrocarbon, natural gas and synthetic crude oil prices. Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates, and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies, and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in liquid hydrocarbon, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.
- Estimated quantities of liquid hydrocarbons, natural gas and synthetic crude oil. Such quantities are based on a combination of proved and probable reserves such that the combined volumes represent the most likely expectation of recovery. These estimates are based on work performed by our engineers for liquid hydrocarbons and natural gas, and by outside consultants for synthetic crude oil. We evaluate our reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. Reserves are adjusted as new information becomes available. By definition, probable reserve estimates are less precise than proved reserve estimates.
- Expected timing of production. Production forecasts are the outcome of engineer studies which estimate proved and probable reserves. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.
- Future margins on refined products produced and sold. Our estimates of future refined product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, capital expenditures, and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews.
- Discount rate commensurate with the risks involved. We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.
- Future capital requirements. Our estimates of future capital requirements are based on authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

The need to test for impairment can be based on several indicators, including a significant reduction in prices of liquid hydrocarbons, natural gas or synthetic crude oil, unfavorable adjustments to reserves, significant changes in the expected timing of production, significant reduction in refining margins, other changes to contracts or changes in the regulatory environment in which the property is located.

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field for E&P assets, project level for oil sands mining assets, refinery and associated distribution system level or pipeline system level for refining and transportation assets, or site level for retail stores. If the sum of the undiscounted estimated pretax cash flows is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value.

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Goodwill is tested for impairment at the reporting unit level.

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pricing and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Acquisitions

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment and identifiable intangible assets. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Derivatives

We record all derivative instruments at fair value. A large volume of our commodity derivatives are exchange-traded and require few assumptions in arriving at fair value. Fair value estimation for all our derivative instruments is discussed in Item 8. Financial Statements and Supplementary Data—Note 15 to the consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Expected Future Taxable Income

We must estimate our expected future taxable income to assess the realizability of our deferred income tax assets.

Numerous assumptions are inherent in the estimation of future taxable income, including assumptions about matters that are dependent on future events, such as future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices) and future financial conditions. The estimates and assumptions used in determining future taxable income are consistent with those used in our planning and capital investment reviews.

In determining our overall estimated future taxable income for purposes of assessing the need for additional or adjustments to existing valuation allowances, we consider proved and, in some cases, probable and possible reserves related to our existing producing properties, as well as estimated quantities of liquid hydrocarbon, natural gas and synthetic crude oil related to undeveloped discoveries if, in our judgment, it is likely that development plans will be approved in the foreseeable future. In assessing the release of an existing valuation allowance, we consider the preponderance of evidence concerning the realization of the impaired deferred tax asset.

Additionally, we must consider any prudent and feasible tax planning strategies that might minimize the amount of deferred tax liabilities recognized or the amount of any valuation allowance recognized against deferred tax assets, if we can implement these strategies and if we expect to implement these strategies in the event the forecasted conditions actually occur. The principal tax planning strategy available to us relates to the permanent reinvestment of the earnings of our foreign subsidiaries. Assumptions related to the permanent reinvestment of the earnings of our foreign subsidiaries are reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and
- health care cost projections.

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our funded U.S. pension plans and our unfunded U.S. retiree health care plans due to the different projected liability durations of 8 years and 12 years. The selected rates are compared to various similar bond indexes for reasonableness. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate modeling tool. This tool applies a yield curve to the projected benefit plan cash flows using a hypothetical Aa yield curve. The yield curve represents a series of annualized individual discount rates from 1.5 to 30 years. The bonds used are rated Aa or higher by a recognized rating agency and only non-callable bonds are included. Each issue is required to have at least $150 million par value outstanding. The top quartile bonds are selected within each maturity group to construct the yield curve.

Of the assumptions used to measure the yearend obligations and estimated annual net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. Decreasing the discount rates of 5.05 percent for our U.S. pension plans and 5.55 percent for our other U.S. postretirement benefit plans by 0.25 would increase pension obligations and other postretirement benefit plan obligations by $150 million and $26 million and would increase annual defined benefit pension expense and other postretirement benefit plan expense by $15 million and $1 million.

The asset rate of return assumption considers the asset mix of the plans (currently targeted at approximately 75 percent equity securities and 25 percent debt securities for the U.S. funded pension plans and 70 percent equity securities and 30 percent debt securities for the international funded pension plans), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Our long-term asset rate of return assumption is compared to those of other companies and to our historical returns for reasonableness. Decreasing the 8.5 percent asset rate of return assumption by 0.25 would not have a significant impact on our defined benefit pension expense.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans.

Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data—Note 20 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the yearend balance sheets.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, product liability claims and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation; additional information on the extent and nature of site contamination; and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances, outside legal counsel is utilized.

We generally record losses related to these types of contingencies as cost of revenues or selling, general and administrative expenses in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as other taxes. For additional information on contingent liabilities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks related to the volatility of liquid hydrocarbon, natural gas, synthetic crude oil and refined product prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

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

See Item 8. Financial Statements and Supplementary Data—Notes 15 and 16 to the consolidated financial statement for more information about the fair value measurement of our derivatives, as well as the amounts recorded in our consolidated balance sheets and statements of income for those which qualify as hedges and those not designated as hedges.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management has the authority, within board-approved levels, to protect prices on forecasted sales, as deemed appropriate. We use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our different businesses. We also may utilize the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical transactions.

We regularly use commodity derivative instruments in the E&P segment to manage natural gas price risk during the time that the natural gas is held in storage before it is sold or on natural gas that is purchased to be marketed with our own natural gas production. We may act opportunistically to protect prices on forecasted sales of liquid hydrocarbon, natural gas or synthetic crude oil in our E&P or OSM segments.

Our RM&T segment primarily uses commodity derivative instruments to manage price risk on crude oil and refined product inventories. We also use derivative instruments to manage price risk related to the acquisition of foreign-sourced crude oil and ethanol blended with refined petroleum products. In addition, we may use commodity derivative instruments to manage risk on fixed price contracts for the sale of refined products. The majority of these derivatives are exchange-traded contracts for crude oil and refined products.

Open Commodity Derivative Positions and Sensitivity Analysis

In the table below are our significant open derivative contracts at December 31, 2010, all of which were for our RM&T segment. These contracts enable us to effectively correlate our commodity price exposure to the relevant market indicators, thereby mitigating price risk.

	December 31, 2010				
	Position	Bbls per Day		Weighted Average (Dollars per Bbl)	Benchmark
Crude Oil					
Exchange-traded	Long[a]	36,608	$	89.67	CME and IPE Crude[b] [c]
Exchange-traded	Short[a]	(61,485)	$	88.03	CME and IPE Crude[b] [c]

	Position	Bbls per Day		Weighted Average (Dollars per Gallon)	Benchmark
Refined Products					
Exchange-traded	Long[d]	13,008	$	2.40	CME Heating Oil and RBOB[b] [e]
Exchange-traded	Short[d]	(11,044)	$	2.46	CME Heating Oil and RBOB[b] [e]

(a) *87 percent of these contracts expire in the first quarter of 2011.*

(b) Chicago Mercantile Exchange ("CME").

(c) International Petroleum Exchange ("IPE").

(d) 98 percent of these contracts expire in the first quarter of 2011.

(e) Reformulated Gasoline Blendstock for Oxygenate Blending ("RBOB").

Sensitivity analysis of the incremental effects on income from operations ("IFO") of hypothetical 10 percent and 25 percent increases and decreases in commodity prices for open commodity derivative instruments as of December 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								
Natural gas	$	(1)	$	(3)	$	1	$	3
RM&T Segment								
Crude oil	$	(71)	$	(177)	$	82	$	205
Refined products		9		22		(9)		(22)

We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risk should be mitigated by price changes in the underlying physical commodity. Effects of these offsets are not reflected in the above sensitivity analysis.

We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles. Changes to the portfolio after December 31, 2010, would cause future IFO effects to differ from those presented above.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2010, we had multiple interest rate swap agreements with a total notional amount of $1.45 billion at a weighted-average, LIBOR-based, floating rate of 4.43 percent. These interest rate swaps are designated as fair value hedges, which effectively results in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2010, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities)[a]		
Receivable from United States Steel	$ 246	$ 1 [c]
Interest rate swap agreements	$ 32 [b]	$ 3 [c]
Long-term debt, including amounts due within one year	$ (8,364)[b]	$ (503)[c]

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

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

(c) For receivables from United States Steel and long-term debt, this assumes a 10 percent decrease in the weighted average yield-to-maturity of our receivables and long-term debt at December 31, 2010. For interest rate swap agreements, this assumes a 10 percent decrease in the effective swap rate at December 31, 2010.

At December 31, 2010, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. There were no foreign currency forward or option contracts open at December 31, 2010.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed and master netting agreements are used when appropriate.

Safe Harbor

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

Item 8. Financial Statements and Supplementary Data

Index

Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States of America. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organizational arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Clarence P. Cazalot, Jr.
President and
Chief Executive Officer

/s/ Janet F. Clark
Executive Vice President
and Chief Financial
Officer

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

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a – 15(f) under the Securities Exchange Act of 1934). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon's management concluded that its internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of Marathon's internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Clarence P. Cazalot, Jr.
President and
Chief Executive Officer

/s/ Janet F. Clark
Executive Vice President
and Chief Financial
Officer

Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the "Company") at December 31, 2010, and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2011

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	2010	2009	2008
Revenues and other income:			
Sales and other operating revenues (including consumer excise taxes)	$ 72,204	$ 53,190	$ 74,710
Sales to related parties	117	97	1,879
Income from equity method investments	414	298	765
Net gain on disposal of assets	777	205	423
Other income	109	166	188
Total revenues and other income	73,621	53,956	77,965
Costs and expenses:			
Cost of revenues (excludes items below)	56,734	40,377	59,512
Purchases from related parties	624	485	715
Consumer excise taxes	5,208	4,924	5,065
Depreciation, depletion and amortization	2,965	2,604	2,108
Long-lived asset impairment	479	19	21
Goodwill impairment	-	-	1,412
Selling, general and administrative expenses	1,363	1,263	1,382
Other taxes	433	387	482
Exploration expenses	498	307	489
Total costs and expenses	68,304	50,366	71,186
Income from operations	5,317	3,590	6,779
Net interest and other	(103)	(149)	(28)
Loss on early extinguishment of debt	(92)	-	-
Income from continuing operations before income taxes	5,122	3,441	6,751
Provision for income taxes	2,554	2,257	3,367
Income from continuing operations	2,568	1,184	3,384
Discontinued operations	-	279	144
Net income	$ 2,568	$ 1,463	$ 3,528
Per Share Data			
Basic:			
Income from continuing operations	$ 3.62	$ 1.67	$ 4.77
Discontinued operations	$ -	$ 0.39	$ 0.20
Net income	$ 3.62	$ 2.06	$ 4.97
Diluted:			
Income from continuing operations	$ 3.61	$ 1.67	$ 4.75
Discontinued operations	$ -	$ 0.39	$ 0.20
Net income	$ 3.61	$ 2.06	$ 4.95
Dividends	$ 0.99	$ 0.96	$ 0.96

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 3,951	$ 2,057
Receivables, less allowance for doubtful accounts of $7 and $14	5,972	4,677
Receivables from related parties	58	60
Inventories	3,453	3,622
Other current assets	395	221
Total current assets	13,829	10,637
Equity method investments	1,802	1,970
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $19,805 and $17,185	32,222	32,121
Goodwill	1,380	1,422
Other noncurrent assets	781	902
Total assets	$ 50,014	$ 47,052
Liabilities		
Current liabilities:		
Accounts payable	$ 8,000	$ 6,982
Payables to related parties	49	64
Payroll and benefits payable	418	399
Accrued taxes	1,447	547
Deferred income taxes	324	403
Other current liabilities	580	566
Long-term debt due within one year	295	96
Total current liabilities	11,113	9,057
Long-term debt	7,601	8,436
Deferred income taxes	3,569	4,104
Defined benefit postretirement plan obligations	2,171	2,056
Asset retirement obligations	1,354	1,099
Deferred credits and other liabilities	435	390
Total liabilities	26,243	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 shares authorized)	-	-
Held in treasury, at cost – 60 million and 61 million shares	(2,665)	(2,706)
Additional paid-in capital	6,756	6,738
Retained earnings	19,907	18,043
Accumulated other comprehensive loss	(997)	(934)
Total stockholders' equity	23,771	21,910
Total liabilities and stockholders' equity	$ 50,014	$ 47,052

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	2010	2009	2008
Increase in cash and cash equivalents			
Operating activities:			
Net income	$ 2,568	$ 1,463	$ 3,528
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss on early extinguishment of debt	92	-	-
Discontinued operations	-	(279)	(144)
Deferred income taxes	(600)	1,072	94
Long-lived asset impairments	479	19	21
Goodwill impairment	-	-	1,412
Depreciation, depletion and amortization	2,965	2,604	2,108
Pension and other postretirement benefits, net	44	(116)	133
Exploratory dry well costs and unproved property impairments	225	81	170
Net gain on disposal of assets	(777)	(205)	(423)
Equity method investments, net	22	42	62
Changes in:			
Current receivables	(1,176)	(1,632)	2,612
Inventories	(171)	(126)	(246)
Current accounts payable and accrued liabilities	2,070	2,169	(2,532)
All other operating, net	132	118	(262)
Net cash provided by continuing operations	5,873	5,210	6,533
Net cash provided by discontinued operations	-	58	219
Net cash provided by operating activities	5,873	5,268	6,752
Investing activities:			
Additions to property, plant and equipment	(4,762)	(6,231)	(6,989)
Disposal of assets	2,131	865	999
Trusteed funds - withdrawals	-	16	752
Investments - loans and advances	(45)	(23)	(117)
Investments - repayments of loans and return of capital	102	94	93
Investing activities of discontinued operations	-	(84)	(127)
All other investing, net	(47)	125	(16)
Net cash used in investing activities	(2,621)	(5,238)	(5,405)
Financing activities:			
Borrowings	-	1,491	1,247
Debt issuance costs	-	(11)	(7)
Debt repayments	(665)	(81)	(1,366)
Purchases of common stock	-	-	(402)
Dividends paid	(704)	(679)	(681)
All other financing, net	11	4	16
Net cash used in financing activities	(1,358)	724	(1,193)
Effect of exchange rate changes on cash:			
Continuing operations	-	19	(44)
Discontinued operations	-	(1)	(24)
Net increase in cash and cash equivalents	1,894	772	86
Cash and cash equivalents at beginning of period	2,057	1,285	1,199
Cash and cash equivalents at end of period	$ 3,951	$ 2,057	$ 1,285

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

(In millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance as of January 1, 2008	$ -	$ 765	$ -	$ (2,384)	$ 6,679	$ 14,412	$ (249)	$ 19,223
Shares issued - stock based compensation	-	-	-	76	(63)	-	-	13
Shares exchanged	-	2	-	-	2	-	-	4
Shares repurchased	-	-	-	(412)	-	-	-	(412)
Stock-based compensation	-	-	-	-	78	-	-	78
Net income	-	-	-	-	-	3,528	-	3,528
Other comprehensive loss	-	-	-	-	-	-	(344)	(344)
Dividends paid	-	-	-	-	-	(681)	-	(681)
Balance as of December 31, 2008	$ -	$ 767	$ -	$ (2,720)	$ 6,696	$ 17,259	$ (593)	$ 21,409
Shares issued - stock based compensation	-	-	-	20	(9)	-	-	11
Shares exchanged	-	2	-	-	(2)	-	-	-
Shares repurchased	-	-	-	(6)	-	-	-	(6)
Stock-based compensation	-	-	-	-	53	-	-	53
Net income	-	-	-	-	-	1,463	-	1,463
Other comprehensive income (loss)	-	-	-	-	-	-	(341)	(341)
Dividends paid	-	-	-	-	-	(679)	-	(679)
Balance as of December 31, 2009	$ -	$ 769	$ -	$ (2,706)	$ 6,738	$ 18,043	$ (934)	$ 21,910
Shares issued - stock based compensation	-	-	-	46	(12)	-	-	34
Shares exchanged	-	1	-	-	(1)	-	-	-
Shares repurchased	-	-	-	(5)	-	-	-	(5)
Stock-based compensation	-	-	-	-	31	-	-	31
Net income	-	-	-	-	-	2,568	-	2,568
Other comprehensive income (loss)	-	-	-	-	-	-	(63)	(63)
Dividends paid	-	-	-	-	-	(704)	-	(704)
Balance as of December 31, 2010	$ -	$ 770	$ -	$ (2,665)	$ 6,756	$ 19,907	$ (997)	$ 23,771

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable for Common Stock	Treasury Stock
Balance as of January 1, 2008	5	765	5	(55)
Shares issued - acquisition				
Shares issued - stock based compensation	-	-	-	2
Shares exchanged	(2)	2	(2)	-
Shares repurchased	-	-	-	(8)
Balance as of December 31, 2008	3	767	3	(61)
Shares issued - stock based				
Shares exchanged	(2)	2	(2)	-
Balance as of December 31, 2009	1	769	1	(61)
Shares issued - stock based compensation	-	-	-	1
Shares exchanged	(1)	1	(1)	-
Balance as of December 31, 2010	-	770	-	(60)

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

(In millions)	2010	2009	2008
Net income	$ 2,568	$ 1,463	$ 3,528
Other comprehensive loss			
Post-retirement and post-employment plans			
Change in actuarial loss	(76)	(564)	(397)
Income tax benefit on post-retirement and post-employment plans	7	208	147
Post-retirement and post-employment plans, net of tax	(69)	(356)	(250)
Derivative hedges			
Net unrecognized gain (loss)	5	24	(91)
Income tax benefit (provision) on derivatives	1	(12)	24
Derivative hedges, net of tax	6	12	(67)
Foreign currency translation and other			
Unrealized gain (loss)	-	4	(43)
Income tax benefit (provision) on foreign currency translation and other	-	(1)	16
Foreign currency translation and other, net of tax	-	3	(27)
Other comprehensive loss	(63)	(341)	(344)
Comprehensive income	$ 2,505	$ 1,122	$ 3,184

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

1. Summary of Principal Accounting Policies

We are engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; oil sands mining and bitumen upgrading in Canada; domestic refining, marketing and transportation of crude oil and petroleum products; and worldwide marketing and transportation of products manufactured from natural gas, such as liquefied natural gas ("LNG") and methanol.

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority shareholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are carried at our share of net assets plus loans and advances. Such investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

Reclassifications – We have revised prior year revenues and cost of revenues in the consolidated statements of income. Some of the sales from our Exploration and Production to our Refining, Marketing, and Transportation segment were presented as third-party revenues and should have been classified as intersegment revenues. This did not change consolidated income or segment income. The following reflects the reclassifications made:

(In millions)	2009	2008
Sales and other operating revenues, previously reported	$ 53,373	$ 74,875
Reclassification of revenues	(183)	(165)
Sales and other operating revenues, adjusted	$ 53,190	$ 74,710
Cost of revenues, previously reported	$ 40,560	$ 59,677
Reclassification of cost of revenues	(183)	(165)
Cost of revenues, adjusted	$ 40,377	$ 59,512

Use of estimates – The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the continental U.S., production volumes of liquid hydrocarbons and natural gas are sold immediately and transported via pipeline. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Rebates from vendors are recognized as a reduction of cost of revenues when the initiating transaction occurs. Incentives that are derived from contractual provisions are accrued based on past experience and recognized in cost of revenues.

Consumer excise taxes – We are required by various governmental authorities, including countries, states and municipalities, to collect and remit taxes on certain consumer products. Such taxes are presented on a gross basis in revenues and costs and expenses in the consolidated statements of income.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable and allowance for doubtful accounts – Our receivables primarily consist of customer accounts receivable, including proprietary credit card receivables. The allowance for doubtful accounts is the best estimate of the amount of probable credit losses in our proprietary credit card receivables. We determine the allowance based on historical write-off experience and the volume of proprietary credit card sales. We review the allowance quarterly and past-due balances over 180 days are reviewed individually for collectability. All other customer receivables are recorded at the invoiced amounts and generally do not bear interest. Account balances for these customer receivables are charged directly to bad debt expense when it becomes probable the receivable will not be collected.

Inventories – Inventories are carried at the lower of cost or market value. Cost of inventories is determined primarily under the last-in, first-out ("LIFO") method.

We may enter into a contract to sell a particular quantity and quality of crude oil or refined product at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory, except for those arrangements accounted for as derivative instruments.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. We also have limited authority to use selective derivative instruments that assume market risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions.

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and financing costs as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2010 and 2009.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio and we may use commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used to manage price risk on: (1) the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce, (2) inventories, (3) fixed price sales of refined products, (4) the acquisition of foreign-sourced crude oil, and (5) the acquisition of ethanol for blending with refined products. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Contingent credit features – Our derivative instruments contain no significant contingent credit features.

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

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities, which include our bitumen mining and upgrading.

Property acquisition costs – Costs to acquire mineral interests in traditional oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and to construct or expand oil sand mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include our bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 1 to 43 years.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 42 years.

Impairments – We evaluate our oil and gas producing properties, which include our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on proved and probable reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors in addition to the use of an undiscounted future net cash flow approach. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. Unproved property investments deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows. Impairment expense for unproved oil and natural gas properties is reported in exploration expenses.

Refining, marketing and transportation assets are reviewed for impairment whenever events or changes in the circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset.

Dispositions – When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs – Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable. If recoveries of remediation costs from third parties are probable, a receivable is recorded and is discounted when the estimated amount is reasonably fixed and determinable.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities.

To a lesser extent, conditional asset retirement obligations for removal and disposal of fire-retardant material from certain refining facilities have also been recognized. The amounts recorded for such obligations are based on the most probable current cost projections. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain refinery, pipeline, marketing and bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining and upgrading facilities, and on a straight-line basis for refining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

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

The fair value of our restricted stock awards and common stock units is determined based on the fair market value of Marathon common stock on the date of grant.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted. Compensation expense is recognized over the vesting period and is adjusted if conditions of the restricted stock award are not met. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

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 4.

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 15.

Oil and Gas Reserve Estimation and Disclosure standards were issued by the Financial Accounting Standards Board ("FASB") in January 2010, which aligns the FASB's reporting requirements with the below requirements of the Securities and Exchange Commission ("SEC"). The FASB also addresses the impact of changes in the SEC's rules and definitions on accounting for oil and gas producing activities. Similar to the SEC requirements, the FASB requirements were effective for periods ending on or after December 31, 2009. 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. The required disclosures are presented in Supplementary Information on Oil and Gas Producing Activities (Unaudited).

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

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

As with the FASB standard described above, adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The additional disclosures required by the SEC can be found in Item 1. Business – Reserves.

Measuring liabilities at fair value, a FASB accounting standards update, was issued in August 2009. This update provides clarification for circumstances in which a quoted price in an active market for an identical liability is not available. In such circumstances, an entity is required to measure fair value using (1) the quoted price of the identical liability when traded as an asset, or (2) quoted prices for similar liabilities or similar liabilities when traded as assets, or (3) another valuation technique consistent with the fair value measurement principles such as an income approach or a market approach. The new update for measuring liabilities at fair value was effective for the third quarter of 2009. Adoption did not have an impact on our consolidated results of operations, financial position or cash flows.

Interim disclosures about fair value of financial instruments were expanded by the FASB in April 2009. Disclosures about fair value of financial instruments are now required in interim reporting periods for publicly traded companies. This change was effective for the second quarter of 2009 and did not require disclosures for earlier periods presented for comparative purposes. Adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The required disclosures are presented in Note 15.

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

Disclosure requirements for derivative instruments and hedging activities were expanded by the FASB in March 2008 to provide information regarding (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. Requirements include qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. The amendments were effective January 1, 2009 and encouraged, but did not require, disclosures for earlier periods presented for comparative purposes at initial adoption. The required disclosures appear in Note 16.

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

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

An employer's disclosures about plan assets of defined benefit pension or other postretirement plans were expanded in December 2008 by the FASB. Additional disclosures about investment policies and strategies, the reporting of fair value by asset category and other information about fair value measurements is required. This was effective January 1, 2009. Upon initial application, these new disclosures are not required for earlier periods that are presented for comparative purposes. These additional disclosures are presented in Note 20.

3. Information about United States Steel

The USX Separation – Prior to December 31, 2001, Marathon had two outstanding classes of common stock: USX - Marathon Group common stock, which was intended to reflect the performance of our energy business, and USX - U.S. Steel Group common stock ("Steel Stock"), which was intended to reflect the performance of our steel business. On December 31, 2001, in a tax-free distribution to holders of Steel Stock, we exchanged the common stock of United States Steel for all outstanding shares of Steel Stock on a one-for-one basis (the "USX Separation"). In connection with the USX Separation, Marathon and United States Steel entered into a number of agreements, including:

Financial Matters Agreement – Marathon and United States Steel entered into a Financial Matters Agreement that provides for United States Steel's assumption of certain industrial revenue bonds and certain other financial obligations of Marathon. The Financial Matters Agreement also provides that, on or before December 31, 2011, United States Steel will provide for our discharge from any remaining liability under any of the assumed industrial revenue bonds.

Under the Financial Matters Agreement, United States Steel has all of the existing contractual rights under the leases assumed, including all rights related to purchase options, prepayments or the grant or release of security interests. However, United States Steel has no right to increase amounts due under or lengthen the term of any of the assumed leases, other than extensions set forth in the terms of any of the assumed leases.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain cokemaking facilities at United States Steel Clairton Works. We guaranteed to the limited partners all obligations of United States Steel under the partnership documents ("the Clairton 1314B Guarantee"). The Financial Matters Agreement requires United States Steel to use commercially reasonable efforts to have Marathon released from its obligations under this guarantee. The Clairton 1314B Partnership was terminated on October 31, 2008. We were not released from our obligations under the Clairton 1314B Guarantee upon termination of the partnership. As a result, we continue to guarantee the United States Steel indemnification of the former limited partners for certain income tax exposures.

The Financial Matters Agreement requires us to use commercially reasonable efforts to assure compliance with all covenants and other obligations to avoid the occurrence of a default or the acceleration of payments on the assumed obligations.

United States Steel's obligations to Marathon under the Financial Matters Agreement are general unsecured obligations that rank equal to United States Steel's accounts payable and other general unsecured obligations. The Financial Matters Agreement does not contain any financial covenants and United States Steel is free to incur additional debt, grant mortgages on or security interests in its property and sell or transfer assets without our consent.

4. Variable Interest Entities

The owners of 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 December 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 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 Variable Interest Entity ("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 result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $778 million as of December 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.

In December 2010, we closed the sale of our Minnesota assets, plus related inventories. Certain terms of the transaction resulted in the creation of variable interests in a VIE that owns the Minnesota assets. These variable interests include our ownership of a preferred equity interest in the buyer, operating margin support in the form of a capped liquidity guarantee, and reimbursements to us for costs incurred in connection with transition services provided to the buyer. Our preferred equity interest in this VIE was reflected at $80 million in other noncurrent assets on the consolidated balance sheet as of December 31 2010. At December 31, 2010, there was an additional $107 million receivable due from the buyer in the first quarter of 2011 related to a portion of the inventories sold.

We are not the primary beneficiary of this VIE and therefore do not consolidate it; we lack the power to control or direct the activities that impact the VIE's operations and economic performance. Our preferred equity does not allow us to appoint a majority of the Board of Managers and limits our ability to vote only certain matters. Also, individually and cumulatively, none of our other variable interests expose us to residual returns or expected losses that are significant to the VIE.

Our maximum exposure to loss due to this VIE is $258 million. Our maximum exposure to loss was quantified based on contractual arrangements related to the sale. We did not provide any financial assistance to the buyer outside of our contractual arrangements related to the sale. See Note 6 for values related to each individual variable interest.

5. Related Party Transactions

During 2010, 2009 and 2008 only our equity method investees were considered related parties including:

- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes liquefied petroleum gas.
- The Andersons Clymers Ethanol LLC, in which we have a 35 percent interest, and The Andersons Marathon Ethanol LLC, in which we have a 50 percent interest ("Ethanol investments"). These companies each own an ethanol production facility.
- Atlantic Methanol Production Company LLC ("AMPCO"), in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.
- Centennial Pipeline LLC ("Centennial"), in which we have a 50 percent interest. Centennial operates a refined products pipeline and storage facility.
- Equatorial Guinea LNG Holdings Limited ("EGHoldings"), in which we have a 60 percent noncontrolling interest.
- LOOP LLC, in which we have a 51 percent noncontrolling interest. LOOP LLC operates an offshore oil port.
- Pilot Travel Centers LLC ("PTC"), in which we sold our 50 percent interest in October 2008. PTC owns and operates travel centers primarily in the United States.
- Poseidon Oil Pipeline Company, LLC ("Poseidon"), in which we have a 28 percent interest. Poseidon transports crude oil.

Related party sales to PTC consisted primarily of petroleum products. In the fourth quarter of 2008, we completed the sale of our 50 percent ownership interest in PTC.

Revenues from related parties were as follows:

(In millions)	2010	2009	2008
EGHoldings	$ 43	$ 44	$ 39
Centennial	54	34	31
Other equity method investees	20	19	20
PTC	-	-	1,789
Total revenues from related parties	$ 117	$ 97	$ 1,879

Purchases from related parties were as follows:

(In millions)	2010	2009	2008
Alba Plant LLC	$ 177	$ 143	$ 235
Ethanol investments	143	143	188
Poseidon	146	53	154
Centennial	72	58	61
LOOP LLC	35	40	35
Other equity method investees	51	48	42
Total purchases from related parties	$ 624	$ 485	$ 715

Current receivables from related parties were as follows:

(In millions)	December 31, 2010	December 31, 2009
EGHoldings	$ 40	$ 36
Poseidon	4	11
Alba Plant LLC	10	10
AMPCO	3	2
Other equity method investees	1	1
Total receivables from related parties	$ 58	$ 60

Payables to related parties were as follows:

(In millions)	December 31, 2010	December 31, 2009
Poseidon	$ 17	$ 20
LOOP LLC	3	17
Ethanol investments	6	9
Alba Plant LLC	16	9
Other equity method investees	7	9
Total payables to related parties	$ 49	$ 64

6. Dispositions

Assets Held for Sale

In December 2010, we signed a sales agreement to sell our E&P segment's Norwegian outside-operated interest in the Gudrun field development and the Brynhild and Eirin exploration areas, for a transaction value of $85 million plus working capital adjustments. We expect the sales transaction to close in the first quarter of 2011, subject to Norwegian governmental approval. A $64 million pretax loss on this disposition was recognized in the fourth quarter of 2010.

As of December 31, 2010, the Gudrun assets and liabilities held for sale are reported in the consolidated balance sheet as follows:

(In millions)	
Other current assets	$ 5
Other noncurrent assets	85
Total assets held for sale	90
Other current liabilities	11
Total liabilities held for sale	$ 11

Minnesota disposition - In December 2010, we closed the sale of our Refining, Marketing, and Transportation ("RM&T") segment's St. Paul Park, Minnesota, refinery (including associated terminal, tankage and pipeline investments) and 166 SuperAmerica retail outlets (collectively, "Minnesota Assets"), plus related inventories. The transaction value was approximately $935 million. The terms of the sale included (1) a preferred stock interest in the entity that holds the Minnesota Assets with a stated value of $80 million, (2) a maximum $125 million earnout provision payable to us over eight years, (3) a maximum $60 million of margin support payable to the buyer over two years, (4) a receivable from the buyer of $107 million payable in the first quarter of 2011, and (5) guarantees with a maximum exposure of $11 million made on behalf of and to the buyer related to a limited number of convenience store sites. As a result of this continuing involvement, the related gain on sale of $89 million was deferred. We received $740 million in cash excluding closing adjustments but prior to post closing adjustments. The timing and amount of deferred gain ultimately recognized in the income statement is subject to the resolution of our continuing involvement.

We will provide transition services for a period of twelve months, that can be extended for up to an additional six months at the buyer's option. The buyer can cancel the transition services arrangement at any time with minimal notice. Although, we will provide personnel to operate and maintain the Minnesota Assets, the buyer will provide management and operational strategy for the refinery.

Angola disposition – During 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 of $811 million. We retained a 10 percent outside-operated interest in Block 32.

Gabon disposition – 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 for 2009.

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

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

In June 2009, we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. An initial $100 million payment was received at closing. Additional fixed proceeds of $135 million will be received at the earlier of first commercial gas or December 31, 2012. A $154 million impairment was recognized in discontinued operations in the second quarter of 2009.

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

Our Irish 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. Revenues and pretax income on these dispositions are shown in the table below.

(In millions)	2009	2008
Revenues applicable to discontinued operations	$ 188	$ 439
Pretax income from discontinued operations	$ 80	$ 221

Norwegian disposition – On October 31, 2008, we closed the sale of our Norwegian outside-operated E&P properties and undeveloped offshore acreage in the Heimdal area of the Norwegian North Sea for net proceeds of $301 million, with a pretax gain of $254 million as of December 31, 2008.

Pilot Travel Centers disposition – On October 8, 2008, we completed the sale of our 50 percent ownership interest in PTC. Sale proceeds were $625 million, with a pretax gain on the sale of $126 million. Immediately preceding the sale, we received a $75 million partial redemption of our ownership interest from PTC that was accounted for as a return of investment. This was an investment of our RM&T segment.

7. 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.

	2010		2009		2008	
(In millions except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 2,568	$ 2,568	$ 1,184	$ 1,184	$ 3,384	$ 3,384
Discontinued operations	-	-	279	279	144	144
Net income	$ 2,568	$ 2,568	$ 1,463	$ 1,463	$ 3,528	$ 3,528
Weighted average common shares outstanding	710	710	709	709	709	709
Effect of dilutive securities	-	2	-	2	-	4
Weighted average common shares, including dilutive effect	710	712	709	711	709	713
Per share:						
Income from continuing operations	$ 3.62	$ 3.61	$ 1.67	$ 1.67	$ 4.77	$ 4.75
Discontinued operations	$ -	$ -	$ 0.39	$ 0.39	$ 0.20	$ 0.20
Net income	$ 3.62	$ 3.61	$ 2.06	$ 2.06	$ 4.97	$ 4.95

The per share calculations above exclude 13 million, 10 million and 5 million stock options and stock appreciation rights in 2010, 2009 and 2008 that were antidilutive.

8. Segment Information

We have four reportable operating segments: Exploration and Production; Oil Sands Mining; Integrated Gas and Refining, Marketing and Transportation. Each of these segments is organized and managed based upon the nature of the products and services they offer.

- Exploration and Production ("E&P") – explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.
- 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.
- Integrated Gas ("IG") – markets and transports products manufactured from natural gas, such as LNG and methanol, on a worldwide basis; and
- Refining, Marketing and Transportation ("RM&T") – refines, markets and transports crude oil and petroleum products, primarily in the Midwest, Gulf Coast and southeastern regions of the U.S.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Foreign currency remeasurement and transaction gains or losses are not allocated to operating segments. Non-cash gains and losses on two natural gas sales contracts in the United Kingdom that were accounted for as derivative instruments, impairments, gains or losses on disposal of assets or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

Revenues from external customers are attributed to geographic areas based on selling location. No single customer accounts for more than 10 percent of annual revenues. Differences between segment totals for income from equity method investments, taxes and depreciation, depletion and amortization and our consolidated 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. Capital expenditures include accruals but not corporate administrative activities. As discussed in Note 6, discontinued operations for our Irish and Gabonese businesses in 2009 and 2008 have been excluded from segment results. Our investment in Pilot Travel Centers LLC, which was reported in our RM&T segment, was sold in the fourth quarter of 2008.

(In millions)	E&P	OSM	IG	RM&T	Total
2010					
Revenues:					
Customer	$ 8,923	$ 744	$ 150	$ 62,387	$ 72,204
Intersegment	2,040	176	-	39	2,255
Related parties	56	-	-	61	117
Segment revenues	11,019	920	150	62,487	74,576
Elimination of intersegment revenues	(2,040)	(176)	-	(39)	(2,255)
Total revenues	$ 8,979	$ 744	$ 150	$ 62,448	$ 72,321
Segment income (loss)	$ 1,940	$ (50)	$ 142	$ 682	$ 2,714
Income from equity method investments	188	-	181	70	439
Depreciation, depletion and amortization	1,935	105	2	914	2,956
Income tax provision (benefit)	2,266	(12)	73	446	2,773
Capital expenditures	2,474	874	2	1,175	4,525

(In millions)	E&P	OSM	IG	RM&T	Total
2009					
Revenues:					
Customer	$ 6,972 (a)	$ 635 (b)	$ 50	$ 45,461	$ 53,118
Intersegment	918 (c)	88 (c)	-	31	1,037
Related parties	59	-	-	38	97
Segment revenues	7,949	723	50	45,530	54,252
Elimination of intersegment revenues	(918)	(88)	-	(31)	(1,037)
Gain on U.K. natural gas contracts	72	-	-	-	72 (d)
Total revenues	$ 7,103	$ 635	$ 50	$ 45,499	$ 53,287
Segment income	$ 1,221	$ 44	$ 90	$ 464	$ 1,819
Income from equity method investments	125	-	144	29	298
Depreciation, depletion and amortization	1,795	124	3	670	2,592
Income tax provision	1,563	6	39	234	1,842
Capital expenditures	2,162	1,115	2	2,570	5,849

(In millions)	E&P	OSM	IG	RM&T	Total
2008					
Revenues:					
Customer	$ 10,886 (a)	$ 1,068 (b)	$ 93	$ 62,445	$ 74,492
Intersegment	1,308 (c)	145 (c)	-	209	1,662
Related parties	52	-	-	1,827	1,879
Segment revenues	12,246	1,213	93	64,481	78,033
Elimination of intersegment revenues	(1,308)	(145)	-	(209)	(1,662)
Gain on U.K. natural gas contracts	218	-	-	-	218 (d)
Total revenues	$ 11,156	$ 1,068	$ 93	$ 64,272	$ 76,589
Segment income (loss)	$ 2,556	$ 258	$ 302	$ 1,179	$ 4,295
Income from equity method investments	225	-	402	178	805
Depreciation, depletion and amortization	1,337	143	3	606	2,089
Income tax provision (benefit)	2,827	93	131	684	3,735
Capital expenditures	2,971	1,038	4	2,954	6,967

(a) We have revised 2009 and 2008 amounts as discussed in Note 1. E&P segment customer revenues were reduced by $269 million in 2009 and $311 million in 2008; however, segment income did not change because an offsetting amount is in cost of revenues.

(b) We have revised 2009 and 2008 amounts as discussed in Note 1. OSM segment customer revenues were increased by $86 million in 2009 and $146 million in 2008; however, segment income did not change because an offsetting amount is in cost of revenues.

(c) We have revised 2009 and 2008 amounts as discussed in Note 1. E&P segment intersegment revenues increased $366 million in 2009 and $510 million in 2008 and OSM intersegment revenues decreased $30 million in 2009 and $55 million in 2008; however, consolidated income did not change because intersegment activity eliminates in consolidation.

(d) 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:

(In millions)	2010	2009	2008
Segment income	$ 2,714	$ 1,819	$ 4,295
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(180)	(422)	(75)
Foreign currency remeasurement of taxes	32	(319)	249
Impairments	(303)[(a)]	(45)[(a)]	(1,437)[(a)]
Gain on U.K. natural gas contracts	-	37	111
Gain on dispositions	407	114	241
Deferred income taxes - tax legislation changes	(45)	-	-
Loss on early extinguishment of debt	(57)	-	-
Discontinued operations	-	279	144
Net income	$ 2,568	$ 1,463	$ 3,528

(a) Significant impairments in 2010 and 2009 are further discussed, on a pretax basis, in Note 15. The 2008 impairment primarily relates to goodwill, see Note 14.

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

(In millions)	2010	2009	2008
Total revenues	$ 72,321	$ 53,287	$ 76,589
Less: Sales to related parties	117	97	1,879
Sales and other operating revenues (including consumer excise taxes)	$ 72,204	$ 53,190	$ 74,710

The following summarizes revenues from external customers by geographic area.

(In millions)	2010	2009	2008
United States	$ 64,229	$ 47,024	$ 68,723
International	8,092	6,263	7,866
Total revenues	$ 72,321	$ 53,287	$ 76,589

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and investments.

(In millions)	2010	2009
United States	$ 18,609	$ 18,500
Canada	9,420	8,774
Equatorial Guinea	2,387	2,584
Norway	1,633	1,743
Other international	2,071	2,510
Total long-lived assets	$ 34,120	$ 34,111

Revenues by product line were:

(In millions)	2010	2009	2008
Refined products	$ 56,025	$ 40,518	$ 59,299
Merchandise	3,369	3,308	3,028
Liquid hydrocarbons	11,349	8,112	11,204
Natural gas	1,295	1,126	2,739
Other products or services	283	223	319
Total revenues	$ 72,321	$ 53,287	$ 76,589

9. Other Items

Net interest and other

(In millions)	2010	2009	2008
Interest:			
Interest income	$ 12	$ 11	$ 55
Interest expense[a]	(511)	(510)	(418)
Income on interest rate swaps	26	17	1
Interest capitalized	410	441	305
Total interest	(63)	(41)	(57)
Other:			
Net foreign currency gains (losses)	(27)	(36)	40
Writeoff of contingent proceeds[b]	(15)	(70)	-
Other	2	(2)	(11)
Total other	(40)	(108)	29
Net interest and other	$ (103)	$ (149)	$ (28)

[a] Excludes $16 million, $27 million and $29 million paid by United States Steel in 2010, 2009 and 2008 on assumed debt.

[b] A portion of the contingent proceeds from the sale of the Corrib natural gas development was written off in the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. The remaining carrying value of this contingent asset was written off in 2010.

Foreign currency transactions - Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

(In millions)	2010	2009	2008
Net interest and other financing costs	$ (27)	$ (36)	$ 40
Provision for income taxes	1	(319)	249
Aggregate foreign currency gains (losses)	$ (26)	$ (355)	$ 289

10. Income Taxes

Income tax provisions (benefits) were:

	2010			2009			2008		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ 183	$ (358)	$ (175)	$ (224)	$ 162	$ (62)	$ 921	$ 192	$1,113
State and local	34	(30)	4	(75)	40	(35)	146	12	158
Foreign	2,937	(212)	2,725	1,484	870	2,354	2,206	(110)	2,096
Total	$3,154	$ (600)	$ 2,554	$1,185	$1,072	$2,257	$3,273	$ 94	$3,367

A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2010	2009	2008
Statutory rate applied to income from continuing operations before income taxes	35 %	35 %	35 %
Effects of foreign operations, including foreign tax credits	16	12	21
Foreign currency remeasurement (gain) loss	-	10	(4)
Effects of nondeductible goodwill impairment	-	-	7
Adjustments to valuation allowances[(a)]	(1)	8	(10)
State and local income taxes, net of federal income tax effects	-	(1)	2
Tax law change	1	-	-
Other	(1)	2	(1)
Effective income tax rate on continuing operations	50 %	66 %	50 %

(a) In 2009, it was determined that we may not be able to realize all recorded foreign tax credit benefits and therefore a valuation allowance was recorded against these benefits. In 2008, we released the valuation allowance on the Norwegian deferred tax asset associated with operating loss carryforwards upon completion of the operated Alvheim/Vilje development offshore Norway, with first production from Alvheim in June 2008 and from Vilje in July 2008.

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 subidy. 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 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.

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	2010	2009
Deferred tax assets:		
Employee benefits	$ 1,079	$ 1,163
Operating loss carryforwards	710	625
Foreign tax credits	2,045	1,934
Other	141	177
Valuation allowances		
Federal[(a)]	(206)	(280)
State	(48)	(45)
Foreign[(b)]	(196)	(157)
Total deferred tax assets	3,525	3,417
Deferred tax liabilities		
Property, plant and equipment	5,663	5,862
Inventories	597	615
Investments in subsidiaries and affiliates	1,116	1,330
Derivative instruments	-	33
Other	42	75
Total deferred tax liabilities	7,418	7,915
Net deferred tax liabilities	$ 3,893	$ 4,498

(a) Our expectation regarding our ability to realize the benefit of foreign tax credits is based on certain assumptions concerning future operating conditions (particularly as related to prevailing commodity prices) and income generated from foreign sources. Federal valuation allowances decreased $73 million in 2010, increased $280 million in 2009 and decreased $29 million in 2008 due to changes in the expected realizability of foreign tax credits.

(b) Foreign valuation allowances increased $39 million in 2010, primarily due to net operating loss carryforwards generated in Angola and Indonesia. Foreign valuation allowances decreased $55 million in 2009, mostly due to the reduction of net operating loss carryforwards as a result of the disposition of exploration and production businesses in Ireland. Foreign valuation allowances decreased $705 million in 2008 primarily due to the release of the Norwegian valuation allowance.

At December 31, 2010, our operating loss carryforwards include $851 million for Angola income tax which have no expiration dates. Canadian operating loss carryforwards of $602 million expire from 2026 through 2030. Indonesia operating loss carryforwards of $129 million do not have expiration dates. State operating loss carryforwards of $1,234 million expire in 2011 through 2028.

Net deferred tax liabilities were classified in the consolidated balance sheet as follows:

	December 31,	
(In millions)	2010	2009
Assets:		
Other current assets	$ -	$ 3
Other noncurrent assets	-	6
Liabilities:		
Current deferred income taxes	324	403
Noncurrent deferred income taxes	3,569	4,104
Net deferred tax liabilities	$ 3,893	$ 4,498

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 2007 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities. As of December 31, 2010, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2004 - 2009
Canada	2006 - 2009
Equatorial Guinea	2006 - 2009
Libya	2006 - 2009
Norway	2008 - 2009
United Kingdom	2008 - 2009

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2010	2009	2008
Beginning balance	$ 75	$ 39	$ 40
Additions based on tax positions related to the current year	28	30	-
Reductions based on tax positions related to the current year	(1)	(2)	-
Additions for tax positions of prior years	25	30	24
Reductions for tax positions of prior years	(12)	(15)	(26)
Settlements	(12)	(7)	1
Ending balance	$ 103	$ 75	$ 39

If the unrecognized tax benefits as of December 31, 2010 were recognized, $94 million would affect our effective income tax rate. There were $21 million of uncertain tax positions as of December 31, 2010 for which it is reasonably possible that the amount of unrecognized tax benefits would decrease during 2011.

Interest and penalties totaled $5 million expense in the year ended December 31, 2010. For the year ended December 31, 2009, interest and penalties were not significant and were a $14 million credit to income for the year ended December 31, 2008. As of December 31, 2010, 2009 and 2008, $15 million, $7 million and $8 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $4,563 million in 2010, $2,947 million in 2009, and $4,029 million in 2008.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2010 amounted to $1,949 million for which no deferred U.S. income tax provision has been recorded because we intend to permanently reinvest such income in those foreign operations. If such income was not permanently reinvested, income tax expense of up to $682 million would be recorded.

11. Inventories

(In millions)	December 31, 2010	December 31, 2009
Liquid hydrocarbons, natural gas and bitumen	$ 1,275	$ 1,393
Refined products and merchandise	1,774	1,790
Supplies and sundry items	404	439
Inventories at cost	$ 3,453	$ 3,622

The LIFO method accounted for 85 percent and 85 percent of total inventory value at December 31, 2010 and 2009. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2010 and 2009 by $4,166 million and $3,115 million.

12. Equity Method Investments

(In millions)	Ownership as of December 31, 2010	December 31, 2010	December 31, 2009
EGHoldings	60%	$ 927	$ 986
Alba Plant LLC	52%	303	317
Atlantic Methanol Production Company LLC	45%	210	224
LOOP LLC	51%	181	149
Ethanol investments	(a)	65	62
Other		116	232
Total		$ 1,802	$ 1,970

(a) As discussed in Note 5, Ethanol investments represent our 35 percent ownership in The Andersons Clymers Ethanol LLC and our 50 percent ownership in The Anderson Marathon Ethanol LLC. Our Ethanol investments were impaired in 2008, due to an other-than-temporary loss in value as a result of declining demand and prices for ethanol, a poor outlook for short-term future profitability and, in the case of one production facility, recurring operating losses.

Summarized financial information for equity method investees is as follows:

(In millions)	2010	2009	2008
Income data – year:			
Revenues and other income	$ 2,243	$ 1,916	$ 15,766
Income from operations	999	677	1,608
Net income	841	576	1,436
Balance sheet data – December 31:			
Current assets	$ 898	$ 802	
Noncurrent assets	3,371	4,266	
Current liabilities	513	767	
Noncurrent liabilities	832	807	

As of December 31, 2010, the carrying value of our equity method investments was $192 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining estimated useful lives of the underlying net assets, except for $49 million of the excess related to goodwill.

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $436 million in 2010, $340 million in 2009 and $827 million in 2008. In 2008 we received a $75 million partial redemption of our partnership interest from Pilot Travel Centers that was accounted for as a return of our investment.

13. Property, Plant and Equipment

(In millions)	December 31, 2010	December 31, 2009
E&P		
United States	$ 13,532	$ 12,271
International	11,736	11,434
Total E&P	25,268	23,705
OSM	9,631	8,811
IG	47	46
RM&T	16,624	16,336
Corporate	457	408
Total property, plant and equipment	$ 52,027	$ 49,306
Less accumulated depreciation, depletion and amortization	(19,805)	(17,185)
Net property, plant and equipment	$ 32,222	$ 32,121

Property, plant and equipment includes gross assets acquired under capital leases of $272 million and $247 million at December 31, 2010 and 2009, with related amounts in accumulated depreciation, depletion and amortization of $48 million and $26 million at December 31, 2010 and 2009.

Property impairments were $479 million, $19 million and $21 million in 2010, 2009 and 2008. We assess the carrying value of our assets when events such as commodity price declines, downward reserve revisions or other market factors indicate their value may have decreased. Property impairments are recorded when the assumed fair value of the asset is less than the carrying value. See Note 15 for discussions of the fair value measurements.

Deferred exploratory well costs were as follows:

(In millions)	December 31, 2010	December 31, 2009	December 31, 2008
Amounts capitalized less than one year after completion of drilling	$ 334	$ 679	$ 863
Amounts capitalized greater than one year after completion of drilling	323	150	54
Total deferred exploratory well costs	$ 657	$ 829	$ 917
Number of projects with costs capitalized greater than one year after completion of drilling	7	3	2

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2010 are summarized by geographical area below:

(In millions)	Amount
Gulf of Mexico	$ 147
Angola	125
Other International	51
Total	$ 323

Well costs that have been suspended for longer than one year are associated with seven projects. The majority of these 2008 and 2009 costs are associated with deepwater Gulf of Mexico projects. These costs are suspended pending the completion of an economic evaluation including, but not limited to, results of additional appraisal drilling, facilities, infrastructure, well-test analysis, geological and geophysical data and approval of a development plan. The costs for Angola began in 2004. The development alternatives are being evaluated and optimization efforts continue for this project. The 2004 through 2009 costs incurred on other international projects are pending commencement of FEED and consideration of optimal development plans in 2011. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development.

(In millions)	2010	2009	2008
Beginning Balance	$ 829	$ 917	$ 783
Additions	329	155	413
Dry well expense	(83)	(32)	(63)
Transfers to development	(54)	(211)	(216)
Dispositions	(364)	-	-
Ending Balance	$ 657	$ 829	$ 917

14. Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below the carrying value. We performed our annual impairment test during 2010 and 2009 and no impairment was required. The fair value of each of our reporting units exceeded the book value appreciably; however, should market conditions deteriorate or commodity prices decline significantly, an impairment in our reporting units may be necessary.

2008

We performed our 2008 annual goodwill impairment test during the second quarter for our E&P reporting unit, during the third quarter for our OSM reporting unit and during the fourth quarter for our reporting units comprising the RM&T segment, at which time no impairment to the carrying value of goodwill was identified. We tested goodwill for impairment again in the fourth quarter of 2008 for our E&P and OSM reporting units because of the late 2008 disruption in the credit and equity markets and the significant change in commodity prices impacted several of the significant assumptions used in our determination of fair value.

Since limited market-based data was available, we principally used an income based discounted cash flow model to compute the fair value of our reporting units. In applying this valuation method, there was a significant amount of judgment required, involving estimates regarding amount and timing of future production, commodity prices and the discount rate appropriate for each reporting unit. We used our planning and capital investment projections, which consider factors such as a combination of proved and risk-adjusted probable and possible reserves, expected future commodity prices and operating costs. An appropriate discount rate was selected for the each of the reporting units. We also compared our significant assumptions used to determine the fair value amounts against other market-based information, if available. In addition, we considered several fair value determination scenarios using key assumption sensitivities to corroborate our fair value estimates.

Testing goodwill for impairment is a two step process. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to be impaired, thus the second step of the impairment test is unnecessary. If the carrying amount of a reporting unit exceeds its fair value, the second step of the goodwill impairment test is performed to measure the amount of impairment, if any. Our fourth quarter 2008 fair value estimate for the OSM reporting unit was less than the carrying amount.

The second step of the goodwill impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. The implied fair value of goodwill shall be determined in the same manner as the amount of goodwill recognized in a business combination. This requires a hypothetical purchase price to be established as if the fair value of the reporting unit was the current price paid to acquire the reporting unit. To determine what the implied fair value of the recorded goodwill would be, the fair value for that reporting unit is hypothetically allocated to all assets and liabilities within that reporting unit. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is required to be recognized in an amount equal to that excess.

The second step in the goodwill impairment process indicated there was no remaining implied fair value of goodwill as of December 31, 2008, for the OSM reporting unit. This was largely due to the disruption in the credit and equity markets, which impacts discount rate assumptions, a change in the timing of expected production and the decline in commodity prices. As a result, a $1,412 million impairment of goodwill for the OSM reporting unit was recorded and reported on a separate line of our consolidated statement of income for 2008.

The changes in the carrying amount of goodwill for the years ended December 31, 2010, and 2009, were as follows:

(In millions)	E&P	OSM	RM&T	Total
2009				
Beginning balance	$ 568	$ 1,412	$ 879	$ 2,859
Less: accumulated impairment	-	(1,412)	-	(1,412)
Beginning balance, net	568	-	879	1,447
Deferred tax adjustments	-	-	9	9
Contingent consideration adjustment	-	-	(1)	(1)
Dispositions	(31)	-	(2)	(33)
Ending balance, net	537	-	885	1,422
2010				
Beginning balance, gross	537	1,412	885	2,834
Less: accumulated impairments	-	(1,412)	-	(1,412)
Beginning balance, net	537	-	885	1,422
Contingent consideration adjustment	-	-	(1)	(1)
Dispositions	-	-	(34)	(34)
Purchase price adjustment	-	-	(7)	(7)
Ending balance, net	$ 537	$ -	$ 843	$ 1,380

15. Fair Value Measurements

Fair Values - Recurring

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

	December 31, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 58	$ -	$ 1	$ 81	140
Interest rate	-	32	-	-	32
Derivative instruments, assets	58	32	1	81	172
Derivative instruments, liabilities					
Commodity	$ (102)	$ -	$ (3)	$ -	(105)
Derivative instruments, liabilities	(102)	-	(3)	-	(105)

	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 prices 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 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.

Interest rate derivatives, in Level 3 for 2009, are reported in Level 2 in 2010 because we now corroborate the interest rates used in the fair value measurement to active markets.

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 third-party reporting service, Bloomberg L.P. Since we are unable to independently verify information from the third-party service providers to active markets, all these measures are considered Level 3.

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.

(In millions)	2010	2009	2008
Beginning balance	$ 9	$ (26)	$ (355)
Total realized and unrealized losses (gains):			
Included in net income	23	68	210
Included in other comprehensive income	4	(1)	1
Transfers to Level 2	(30)	-	-
Purchases	2	5	6
Sales	-	(23)	-
Issuances	-	(44)	-
Settlements	(10)	30	112
Ending balance	$ (2)	$ 9	$ (26)

Related to the derivatives in Level 3, net income for the years ended December 31, 2010 and 2009 included unrealized losses of $1 million and $7 million, respectively, and an unrealized gain of $299 million for the year ended December 31, 2008. See Note 16 for income statement impacts of our derivative instruments.

Fair Values – Nonrecurring

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

	Year Ended December 31,			
	2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 147	$ 475	$ 5	$ 15
Long-lived assets held for sale	85	64	311	154
Equity method investment	-	25	-	-

During 2010 and 2009, several long-lived assets held for use were evaluated for impairment due to reductions in estimated reserves, reduced drilling expectations and declining natural gas prices. The fair values of the assets were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

In 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.

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 the fourth quarter of 2010, due to the pending sale of our outside-operated interest in Gudrun, located offshore Norway, we recorded a $64 million loss for this asset held for sale. The fair value of $85 million was based upon the pending transaction, which is a Level 3 market input.

The $154 million 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 upon the fair value of anticipated sale proceeds (see Note 6). 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) contingent proceeds subject to the timing of first commercial 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.

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

	December 31,			
	2010		2009	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 226	$ 220	$ 23	$ 22
Other noncurrent assets	396	231	671	499
Total financial assets	622	451	694	521
Financial liabilities				
Other current liabilities		-	-	-
Long-term debt, including current portion[a]	8,364	7,527	8,754	8,190
Deferred credits and other liabilities	66	67	71	73
Total financial liabilities	$ 8,430	$ 7,594	$ 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. 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. Exceptions to this assessment are

- the current portion of receivables from United States Steel Corporation ("United States Steel"), which is reported in other current assets above and discussed below;
- the current portion of our long-term debt, which is reported with long-term debt above and discussed below; and

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 December 31, 2011, the tenth anniversary of the USX Separation.

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 such 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.

16. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of December 31, 2010 and 2009:

	December 31, 2010			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 32	$ -	$ 32	Other noncurrent assets
Total Designated Hedges	32	-	32	
Not Designated as Hedges				
Commodity	58	102	(44)	Other current assets
Total Not Designated as Hedges	58	102	(44)	
Total	$ 90	$ 102	$ (12)	

	December 31, 2010			
(In millions)	Asset	Liability	**Net Liability**	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 1	$ 3	$ 2	Other current liabilities
Total Not Designated as Hedges	1	3	2	
Total	$ 1	$ 3	$ 2	

	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

We had no cash flow hedges at December 31, 2010. As of December 31, 2009, the following foreign currency forwards and options were designated as cash flow hedges:

(In millions)	Settlement Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards			
Dollar (Canada)	January 2010 - February 2010	$ 24	1.062 [a]

[a] U.S. dollar to foreign currency.

(In millions)	Period	Notional Amount	Weighted Average Exercise Price
Foreign Currency Options			
Dollar (Canada)	January 2010 - September 2010	$ 144	1.042 [a]

[a] U.S. dollar to foreign currency.

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

	Gain (Loss) in OCI		
(In millions)	2010	2009	2008
Foreign currency	$ 4	$ 39	$ (88)
Interest rate	$ -	$ (15)	$ -

Derivatives Designated as Fair Value Hedges

As of December 31, 2010, we had multiple interest rate swap agreements with a total notional amount of $1.45 billion at a weighted-average, LIBOR-based, floating rate of 4.43 percent. As of December 31, 2009, we had multiple interest rate swap agreements with a total notional amount of $1.35 billion at a weighted-average, LIBOR-based, floating rate of 4.37 percent. The interest rate swaps have no hedge ineffectiveness.

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

		Gain (Loss)		
(In millions)	Income Statement Location	2010	2009	2008
Derivative				
Commodity	Sales and other operating revenues	$ (1)	$ (16)	$ 16
Interest rate	Net interest and other financing costs	26	-	30
		25	(16)	46
Hedged Item				
Commodity	Sales and other operating revenues	1	16	(21)
Long-term debt	Net interest and other financing costs	(26)	-	(30)
		$ (25)	$ 16	$ (51)

Derivatives not Designated as Hedges

During 2009, hedge accounting was discontinued prospectively for Kroner (Norway) and Euro foreign currency forwards when it was determined that they were no longer highly effective hedges. The Kroner contracts expired in 2009. The Euro contracts expired in June 2010. Ineffectiveness on these hedges of $3 million was recorded as a gain to net interest and other financing costs in 2009.

(In millions)	Settlement Period	Notional Amount	Weighted Average Forward Rate
Foreign Currency Forwards			
Euro	March 2010 - June 2010	$ 3	1.278 [a]

[a] Foreign currency to U.S. dollar.

The tables below summarize open commodity derivative contracts of our RM&T segment at December 31, 2010 and 2009 that are not designated as hedges. These contracts enable us to effectively correlate our commodity price exposure to the relevant market indicators, thereby mitigating price risk.

December 31, 2010

	Position	Bbls per Day	Weighted Average (Dollars per Bbl)	Benchmark
Crude Oil				
Exchange-traded	Long[a]	36,608	$ 89.67	CME and IPE Crude[b] [c]
Exchange-traded	Short[a]	(61,485)	$ 88.03	CME and IPE Crude[b] [c]

	Position	Bbls per Day	Weighted Average (Dollars per Gallon)	Benchmark
Refined Products				
Exchange-traded	Long[d]	13,008	$ 2.40	CME Heating Oil and RBOB[b] [e]
Exchange-traded	Short[d]	(11,044)	$ 2.46	CME Heating Oil and RBOB[b] [e]

(a) 87 percent of these contracts expire in the first quarter of 2011.
(b) Chicago Mercantile Exchange ("CME").
(c) International Petroleum Exchange ("IPE").
(d) 98 percent of these contracts expire in the first quarter of 2011.
(e) Reformulated Gasoline Blendstock for Oxygen Blending ("RBOB").

December 31, 2009

	Position	Bbls per Day	Weighted Average (Dollars per Bbl)	Benchmark
Crude Oil				
Exchange-traded	Long[a]	61,677	$ 76.67	CME and IPE Crude[b] [c]
Exchange-traded	Short[a]	(54,395)	$ 76.85	CME and IPE Crude[b] [c]

	Position	Bbls per Day	Weighted Average (Dollars per Gallon)	Benchmark
Refined Products				
Exchange-traded	Long[d]	11,773	$ 2.00	CME Heating Oil and RBOB[b] [e]
Exchange-traded	Short[d]	(17,030)	$ 2.00	CME Heating Oil and RBOB[b] [e]

(a) 79 percent of these contracts expired in the first quarter of 2010.
(b) Chicago Mercantile Exchange ("CME").
(c) International Petroleum Exchange ("IPE").
(d) 97 percent of these contracts expired in the first 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)		
(In millions)	Income Statement Location	2010	2009	2008
Commodity	Sales and other operating revenues	$ 120	$ 76	$ 293
Commodity	Cost of revenues	(28)	(70)	(108)
Commodity	Other income	6	12	(3)
Foreign currency	Net interest and other financing costs	-	3	-
		$ 98	$ 21	$ 182

17. Debt

As of December 31, 2010, we had no borrowings against our $3 billion revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

The termination date on $2,625 million of our revolving credit facility is May 2013. The remaining $375 million has a termination date of May 2012. The facility requires a representation at an initial borrowing that there has been no change in our consolidated financial position or operations, considered as a whole which would materially and adversely affect our ability to perform our obligations under the revolving credit facility. Interest on the facility is based on defined short-term market rates. During the term of the agreement, we are obligated to pay a variable facility fee on the total commitment, which at December 31, 2010 was 0.08 percent.

	December 31,	
(In millions)	2010	2009
Marathon Oil Corporation:		
Revolving credit facility due 2012	$ -	$ -
6.125% notes due 2012[(a)]	450	450
6.000% notes due 2012[(a)]	400	400
5.900% notes due 2018[(a)]	894	1,000
6.800% notes due 2032[(a)]	550	550
9.375% debentures due 2012	53	87
9.125% debentures due 2013	114	174
6.500% debentures due 2014[(a)]	700	700
7.500% debentures due 2019[(a)]	688	800
6.000% debentures due 2017[(a)]	682	750
9.375% debentures due 2022	32	65
8.500% debentures due 2023	70	116
8.125% debentures due 2023	131	172
6.600% debentures due 2037[(a)]	750	750
4.550% promissory note, semi-annual payments due 2011 - 2015	340	408
Series A medium term notes due 2022	3	3
4.750% - 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2013 - 2033	221	310
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Sale-leaseback financing due 2011 - 2012	20	29
Capital lease obligation due 2011 - 2012	17	25
Consolidated subsidiaries		
8.375% secured notes due 2012[(a)(b)]	448	448
Capital lease obligations due 2011 - 2024[(c)]	291	265
Total[(d)]	7,854	8,502
Unamortized fair value differential for debt assumed in acquisitions	16	27
Unamortized discount	(16)	(20)
Fair value adjustments [(e)]	42	23
Amounts due within one year	(295)	(96)
Total long-term debt due after one year	$ 7,601	$ 8,436

(a) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

(b) These notes are senior secured notes of Marathon Oil Canada Corporation. The notes are secured by substantially all of Marathon Oil Canada Corporation's assets. In January 2008, we provided a full and unconditional guarantee covering the payment of all principal and interest due under the senior notes.

(c) These obligations as of December 31, 2010 include $73 million related to assets under construction at that date for which a capital lease will commence upon completion of construction. The amounts currently reported are based upon the percent of construction completed as of December 31, 2010 and therefore do not reflect future minimum lease obligations of $164 million related to the asset.

(d) In the event of a change in control, as defined in the related agreements, debt obligations totaling $440 million at December 31, 2010, may be declared immediately due and payable.

(e) See Note 15 for information on interest rate swaps.

Our long term debt agreements do not contain restrictive financial covenants.

United States Steel has assumed responsibility for repayment of a majority of the industrial development and environmental improvement bonds and notes due 2013-2033 as a result of the USX Separation. The Financial Matters Agreement provides that, on or before December 31, 2011, the tenth anniversary of the USX Separation, United States Steel shall pay us an amount equal to the principal amount of, all accrued and unpaid debt service then outstanding on, and any premium required to immediately retire each bond. Upon such payment, we shall retire all then outstanding bonds. In 2010 and 2009, United States Steel refinanced and paid off $89 million and $129 million face value of these bonds. The full $198 million remaining balance, assumed at December 31, 2010, is classified as due within one year. In addition, United State Steel has assumed responsibility for the sale-leaseback financing and capital lease obligations due 2011 through 2012.

The following table shows five years of debt payments.

(In millions)	
2011	$ 295
2012	1,455
2013	224
2014	788
2015	91

In April 2010, we repurchased the following debt 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% debentures due 2017	68
5.900% 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 debt purchases	$ 500

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

See Note 25 for discussion of financing activities subsequent to December 31, 2010.

18. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2010	2009
Beginning balance	$ 1,102	$ 965
Liabilities incurred, including acquisitions	49	54
Liabilities settled	(28)	(65)
Accretion expense (included in depreciation, depletion and amortization)	70	64
Revisions to previous estimates	162	84
Ending balance[(a)]	$ 1,355	$ 1,102

(a) Includes asset retirement obligation of $1 and $3 million classified as short-term at December 31, 2010, and 2009.

19. Supplemental Cash Flow Information

(In millions)		2010	2009	2008
Net cash provided from operating activities from continuing operations included:				
Interest paid (net of amounts capitalized)		$ 107	$ 19	$ 92
Income taxes paid to taxing authorities		2,155	1,663	2,921
Commercial paper and revolving credit arrangements, net:				
Commercial paper	- issuances	$ -	$ 897	$ 46,706
	- repayments	-	(897)	(46,706)
Credit agreements	- borrowings	-	-	404
	- repayments	-	-	(404)
Noncash investing and financing activities:				
Additions to property, plant and equipment				
Asset retirement costs capitalized, excluding acquisitions		$ 207	$ 135	$ 26
Change in capital expenditure accrual		(191)	(343)	30
Debt payments made by United States Steel		105	144	14
Capital lease and sale-leaseback financing obligations increase		33	86	84
Preferred stock received in asset disposition		80	-	-

20. Defined Benefit Postretirement Plans

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the United Kingdom. Through 2010, benefits under these plans have been based primarily on years of service and final average pensionable earnings.

We also have defined benefit plans for other postretirement benefits covering most employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain nonunion and union-represented retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status – The accumulated benefit obligation for all defined benefit pension plans was $2,737 million and $2,659 million as of December 31, 2010 and 2009.

Summary information for our defined benefit pension plans follows. In 2010, only our U.S. plans have accumulated benefit obligations in excess of plan assets, while in 2009 all plans had accumulated benefit obligations in excess of plan assets.

	December 31,		
	2010	2009	
(In millions)	U.S.	U.S.	Int'l
Projected benefit obligation	$ (3,221)	$ (2,989)	$ (395)
Accumulated benefit obligation	(2,365)	(2,300)	(359)
Fair value of plan assets	1,798	1,623	348

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2010		2009		2010	2009
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 2,989	$ 395	$ 2,164	$ 288	$ 685	$ 694
Service cost	92	19	130	14	18	17
Interest cost	153	22	146	22	39	41
Actuarial loss (gain)	287	6	703	85	69	(35)
Foreign currency exchange rate changes	-	(18)	-	26	-	-
Divestiture[(a)]	-	-	-	(30)	-	-
Other	-	6	-	-	-	-
Benefits paid	(300)	(15)	(154)	(10)	(32)	(32)
Benefit obligations at December 31	$ 3,221	$ 415	$ 2,989	$ 395	$ 779	$ 685
Change in plan assets:						
Fair value of plan assets at January 1	$ 1,623	$ 348	$ 1,203	$ 288	$ -	$ -
Actual return on plan assets	214	47	257	52	-	-
Employer contributions	267	20	311	34	-	-
Foreign currency exchange rate changes	-	(14)	-	28	-	-
Divestiture[(a)]	-	-	-	(44)	-	-
Other	(6)	3	6	-	-	-
Benefits paid	(300)	(15)	(154)	(10)	-	-
Fair value of plan assets at December 31	$ 1,798	$ 389	$ 1,623	$ 348	$ -	$ -
Funded status of plans at December 31	$ (1,423)	$ (26)	$ (1,366)	$ (47)	$ (779)	$ (685)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(21)	-	(18)	-	(36)	(34)
Noncurrent liabilities	(1,402)	(26)	(1,348)	(47)	(743)	(651)
Accrued benefit cost	$ (1,423)	$ (26)	$ (1,366)	$ (47)	$ (779)	$ (685)
Pretax amounts in accumulated other comprehensive income:[(b)]						
Net loss (gain)	$ 1,382	$ 41	$ 1,338	$ 71	$ 18	$ (53)
Prior service cost (credit)	81	-	93	-	(24)	(30)

(a) The divestiture is related to our discontinued operations in Ireland, as discussed in Note 6.

(b) Amount excludes those related to LOOP LLC, an equity method investee with defined benefit pension and postretirement plans for which net losses of $9 million and $8 million were recorded in accumulated other comprehensive income, reflecting our 51 percent share.

Components of net periodic benefit cost and other comprehensive income – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive income for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2010		2009		2008		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2010	2009	2008
Components of net periodic benefit cost:									
Service cost	$ 92	$ 19	$ 130	$ 14	$ 127	$ 19	$ 18	$ 17	$ 18
Interest cost	153	22	146	22	135	25	39	41	44
Expected return on plan assets	(139)	(22)	(141)	(21)	(142)	(26)	-	-	-
Amortization									
- prior service cost (credit)	13	-	13	1	13	-	(6)	(5)	(8)
- actuarial loss (gain)	98	5	29	2	29	3	(2)	(5)	1
Other	-	2	-	-	-	-	-		
Net settlement/curtailment loss[a]	69	-	4	18	-	-	-	-	-
Net periodic benefit cost[b]	$ 286	$ 26	$ 181	$ 36	$ 162	$ 21	$ 49	$ 48	$ 55
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):									
Actuarial loss (gain)	$ 211	$ (25)	$ 587	$ 52	$ 532	$ (32)	$ 69	$(34)	$(76)
Amortization of actuarial (loss) gain	(167)	(5)	(33)	(7)	(29)	(3)	2	5	(1)
Prior service cost	-	-	-	-	-	1	-	-	-
Amortization of prior service credit (cost)	(13)	-	(13)	(1)	(13)	-	6	5	8
Total recognized in other comprehensive income	$ 31	$ (30)	$ 541	$ 44	$ 490	$ (34)	$ 77	$(24)	$(69)
Total recognized in net periodic benefit cost and other comprehensive income	$ 317	$ (4)	$ 722	$ 80	$ 652	$ (13)	$ 126	$ 24	$(14)

[a] Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2010 and 2009. Additionally, in 2009 a curtailment and settlement was recorded related to our discontinued operations in Ireland as discussed in Note 6.

[b] Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 are $121 million and $12 million. The 2011 net loss amortization is expected to be higher than the 2010 actual amortization primarily as a result of the decrease in the discount rate as shown in the table below. The estimated prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 is $7 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2010, 2009 and 2008.

	Pension Benefits								
	2010		2009		2008		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2010	2009	2008
Weighted average assumptions used to determine benefit obligation:									
Discount rate	5.05%	5.40%	5.50%	5.70%	6.90%	6.70%	5.55%	5.95%	6.85%
Rate of compensation increase	5.00%	5.10%	4.50%	5.55%	4.50%	4.75%	5.00%	4.50%	4.50%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	5.23%	5.70%	6.90%	6.70%	6.30%	5.80%	6.85%	6.85%	6.60%
Expected long-term return on plan assets	8.50%	6.40%	8.50%	6.10%	8.50%	6.48%	-	-	-
Rate of compensation increase	4.50%	5.55%	4.50%	4.75%	4.50%	5.15%	4.50%	4.50%	4.50%

Expected long-term return on plan assets

U.S. plans – The overall expected long-term return on plan assets assumption for our U.S. plans is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plans' asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans – To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend rates

	2010	2009	2008
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	7.50%	7.00%	7.00%
Post-65	7.00%	6.75%	7.00%
Prescription drugs	7.50%	7.50%	10.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	6.00%
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2018	2014	2012
Post-65	2017	2015	2012
Prescription drugs	2018	2015	2016

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 9	$ 7
Effect on other postretirement benefit obligations	106	87

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plans – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, the plans' targeted asset allocation is comprised of 75 percent equity securities and 25 percent fixed income securities.

The plans' assets are managed by a third-party investment manager. The investment manager has limited discretion to move away from the target allocations based upon the manager's judgment as to current confidence or concern regarding the capital markets. Investments are diversified by industry and type, limited by grade and maturity. The plans' investment policy prohibits investments in any securities in the steel industry and allows derivatives subject to strict guidelines, such that derivatives may only be written against equity securities in the portfolio. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans – Our international plans' target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in six separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2010 and 2009.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1 in the fair value hierarchy. The money market mutual fund is valued at the net asset value ("NAV") of shares held.

Equity securities – Investments in public investment trusts and S&P 500 exchange-traded funds are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Non-public investment trusts are valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and are considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds – Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds held by our international pension plans are benchmarked against a relative public index as defined under the plans' investment policies. These investments are considered Level 2.

Real estate – Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other – Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account and is considered Level 2. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. The insurance carrier contract is funded by premiums paid annually by the company and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by clients. The contract is valued using a market approach based on the underlying investments within the portfolio and is considered Level 2. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity and fixed income securities. The values of the LLCs are determined using an income approach based on discounted cash flows and are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2010 and 2009.

	December 31, 2010							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 8	$ 1	$ -	$ -	$ -	$ -	$ 8	$ 1
Equity securities:								
Investment trusts	25	-	137	-	-	-	162	-
Exchange traded funds	56	-	-	-	-	-	56	-
Private equity	-	-	-	-	67	-	67	-
Investment funds								
Mutual funds - equity[a]	-	161	-	-	-	-	-	161
Pooled funds - equity[b]	-	-	1,072	97	-	-	1,072	97
Pooled funds - fixed income[c]	-	-	350	126	-	-	350	126
Real estate[d]	-	-	-	-	54	-	54	-
Other	-	-	5	4	24	-	29	4
Total investments, at fair value	$ 89	$ 162	$ 1,564	$ 227	$ 145	$ -	$ 1,798	$ 389

	December 31, 2009							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 1	$ -	$ -	$ -	$ -	$ 12	$ 1
Equity securities:								
Investment trusts	21	-	114	-	-	-	135	-
Exchange traded funds	26	-	-	-	-	-	26	-
Private equity	-	-	-	-	42	-	42	-
Investment funds								
Mutual funds - equity[a]	-	145	-	-	-	-	-	145
Pooled funds - equity[b]	-	-	930	87	-	-	930	87
Pooled funds - fixed income[c]	-	-	327	115	-	-	327	115
Real estate[d]	-	-	-	-	36	-	36	-
Other	-	-	92[e]	-	23	-	115	-
Total investments, at fair value	$ 59	$ 146	$ 1,463	$ 202	$ 101	$ -	$ 1,623	$ 348

(a) Includes approximately 60 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy and basic material sectors and the remaining 40 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes FTSE All Share, MSCI World Free, and MSCI Europe (ex UK) as defined by the investment policy.

(b) U.S. – Includes approximately 70 percent of investments held in U.S. and non-U.S. publicly traded common stocks in the consumer staples, consumer discretionary, technology, health and energy sectors and the remaining 30 percent of investments held amongst various other sectors. Int'l – Includes approximately 60 percent of investments held in non-U.S. common stocks (specifically Asia Pacific, except Japan, and the UK) in the financials, technology, materials, health care, and energy sectors and the remaining 40 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes, MSCI AC Asia and FTSE All-Share, as defined by the investment policy.

(c) U.S. – Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which includes treasuries, mortgage-backed securities and industrials and the remaining 20 percent of investments held amongst various other sectors. Int'l – Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financials, sovereigns, collateralized and the remaining 20 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes, as defined by the investment policy.

(d) Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential and land with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

(e) Includes an $86 million receivable for the sale of an investment that closed as of December 31, 2009 but did not cash settle until the next business day.

The following is a reconciliation of the beginning and ending balances recorded for plan assets classified as Level 3 in the fair value hierarchy.

	2010			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 42	$ 36	$ 23	$ 101
Actual return on plan assets	13	4	1	18
Purchases	15	17	-	32
Sales	(3)	(3)	-	(6)
Ending balance	$ 67	$ 54	$ 24	$ 145

	2009			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 35	$ 51	$ 7	$ 93
Actual return on plan assets	2	(21)	1	(18)
Purchases	6	8	15	29
Sales	(1)	(2)	-	(3)
Ending balance	$ 42	$ 36	$ 23	$ 101

Cash flows

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $156 million in 2011. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $22 million and $40 million in 2011.

Estimated future benefit payments – The following gross benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits[(a)]
2011	$ 265	$ 11	$ 40
2012	296	11	43
2013	303	12	46
2014	313	14	49
2015	317	16	53
2016 through 2020	1,619	99	312

(a) Expected Medicare reimbursements for 2011 through 2012 total $8 million. Effective 2013, as a result of the PPACA, future Medicare reimbursements will no longer be tax deductible and must be used to reduce the costs of providing Medicare Part D equivalent prescription drug benefits to retirees.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $75 million in 2010, $59 million in 2009 and $49 million in 2008.

21. Stock-Based Compensation Plans

Description of the Plans

The Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") was approved by our stockholders in April 2007 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2007 Plan also allows us to provide equity compensation to our non-employee directors. No more than 34 million shares of Marathon common stock may be issued under the 2007 Plan and no more than 12 million of those shares may be used for awards other than stock options or stock appreciation rights.

Shares subject to awards under the 2007 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a stock appreciation right is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the stock appreciation right was exercised will count against the number of shares of Marathon common stock reserved for issuance under the 2007 Plan and will not again become available under the 2007 Plan. In addition, the number of shares of Marathon common stock reserved for issuance under the 2007 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2007 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2007 Plan, no new grants were or will be made from the 2003 Incentive Compensation Plan (the "2003 Plan"). The 2003 Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). No new grants will be made from the Prior Plans. Any awards previously granted under the 2003 Plan or the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock-based awards under the Plan

Stock options – We grant stock options under the 2007 Plan. Our stock options represent the right to purchase shares of Marathon common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash or Marathon common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No stock appreciation rights have been granted under the 2007 Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Restricted stock – We grant restricted stock and restricted stock units under the 2007 Plan and previously granted such awards under the 2003 Plan. In 2005, the Compensation Committee began granting time-based restricted stock to certain U.S.-based officers of Marathon and its consolidated subsidiaries as part of their annual long-term incentive package. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees ("restricted stock awards"), based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment, however, certain restricted stock awards granted in 2008 will vest over a four-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2007 Plan and previously maintained such a program under the 2003 Plan. All non-employee directors receive annual grants of common stock units, and they are required to hold those units until they leave the Board of Directors. When dividends are paid on Marathon common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock-based compensation expense

Total employee stock-based compensation expense was $68 million, $76 million and $43 million in 2010, 2009 and 2008, while the total related income tax benefits were $26 million, $29 million and $16 million in the same years. In 2010, 2009 and 2008 cash received upon exercise of stock option awards was $12 million, $4 million and $9 million. Tax benefits realized for deductions for stock awards exercised during 2010, 2009 and 2008 during the period totaled $11 million, $10 million and $19 million.

Stock option awards

During 2010, 2009 and 2008, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2010	2009	2008
Weighted average exercise price per share	$ 30.00	$ 27.62	$ 51.74
Expected annual dividends per share	0.99	0.96	0.96
Expected life in years	5.1	4.9	4.8
Expected volatility	43 %	41 %	30 %
Risk-free interest rate	2.2 %	2.3 %	3.1 %
Weighted average grant date fair value of stock option awards granted	$ 8.70	$ 7.67	$ 13.03

The following is a summary of stock option award activity in 2010.

	Number of Shares	Weighted - Average Exercise price
Outstanding at December 31, 2009	18,230,074	$ 35.01
Granted	4,757,080	30.00
Exercised	(628,849)	21.74
Cancelled	(898,511)	39.22
Outstanding at December 31, 2010	21,459,794	$ 34.12

The intrinsic value of stock option awards exercised during 2010, 2009 and 2008 was $8 million, $3 million and $12 million.

The following table presents information related to stock option awards at December 31, 2010.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted - Average Remaining Contractual Life	Weighted-Average Exercise Price	Number of Shares Under Option	Weighted-Average Exercise Price
$ 12.76-16.81	2,911,936	3	$ 15.61	2,911,936	$ 15.61
23.21-29.24	7,940,103	7	27.09	3,752,957	25.92
30.37-47.91	5,762,608	7	33.85	2,555,946	38.03
51.17-61.33	4,845,147	6	57.07	4,192,212	57.85
Total	21,459,794	6	34.12	13,413,051	35.97

As of December 31, 2010, the aggregate intrinsic value of stock option awards outstanding was $162 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $104 million and 5 years.

As of December 31, 2010, the number of fully-vested stock option awards and stock option awards expected to vest was 21,096,823. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $34.18 and 6 years and the aggregate intrinsic value was $160 million. As of December 31, 2010, unrecognized compensation cost related to stock option awards was $40 million, which is expected to be recognized over a weighted average period of 2 years.

Restricted stock awards

The following is a summary of restricted stock award activity.

	Awards	Weighted-Average Grant Date Fair Value
Unvested at December 31, 2009	1,441,499	$ 44.89
Granted	628,163	31.62
Vested	(626,527)	49.33
Forfeited	(136,897)	40.66
Unvested at December 31, 2010	1,306,238	36.81

The vesting date fair value of restricted stock awards which vested during 2010, 2009 and 2008 was $21 million, $24 million and $38 million. The weighted average grant date fair value of restricted stock awards was $36.81, $44.89, and $47.72 for awards unvested at December 31, 2010, 2009 and 2008.

As of December 31, 2010, there was $29 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 1.8 years.

22. Stockholders' Equity

Securities exchangeable into Marathon common stock – In conjunction with our acquisition of Western Oil Sands Inc. ("Western") 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.

Preferred shares – Also in connection with our acquisition of Western, the Board of Directors authorized a class of voting preferred stock. Upon completion of the acquisition, we issued shares of this voting preferred stock to a trustee, who holds the shares for the benefit of the holders of the Exchangeable Shares discussed above. Each share of voting preferred stock is entitled to one vote on all matters submitted to the holders of Marathon common stock. Each holder of Exchangeable Shares may direct the trustee to vote the number of shares of voting preferred stock equal to the number of shares of Marathon common stock issuable upon the exchange of the Exchangeable Shares held by that holder. In no event will the aggregate number of votes entitled to be cast by the trustee with respect to the outstanding shares of voting preferred stock exceed the number of votes entitled to be cast with respect to the outstanding Exchangeable Shares. Except as otherwise provided in our restated certificate of incorporation or by applicable law, the common stock and the voting preferred stock will vote together as a single class in the election of directors of Marathon and on all other matters submitted to a vote of stockholders of Marathon generally. The voting preferred stock will have no other voting rights except as required by law. Other than dividends payable solely in shares of voting preferred stock, no dividend or other distribution, will be paid or payable to the holder of the voting preferred stock. In the event of any liquidation, dissolution or winding up of Marathon, the holder of shares of the voting preferred stock will not be entitled to receive any assets of Marathon available for distribution to its stockholders. The voting preferred stock is not convertible into any other class or series of the capital stock of Marathon or into cash, property or other rights, and may not be redeemed. In connection with the redemption of the exchangeable shares, these preferred shares were eliminated in June 2010.

Share repurchase plan – The Board of Directors has authorized the repurchase of up to $5 billion of Marathon common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. There have been no stock repurchases since August 2008.

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land and building space, office equipment, production facilities and transportation equipment. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations (including sale-leasebacks accounted for as financings) and for operating lease obligations having initial or remaining noncancelable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations[a]	Operating Lease Obligations
2011	$ 47	$ 148
2012	58	154
2013	44	147
2014	44	132
2015	45	122
Later years	422	275
Sublease rentals	-	(2)
Total minimum lease payments	$ 660	$ 976
Less imputed interest costs	(240)	
Present value of net minimum lease payments	$ 420	

[a] Capital lease obligations include $164 million related to assets under construction as of December 31, 2010. These leases are currently reported in long-term debt based on percentage of construction completed at $73 million.

In connection with past sales of various plants and operations, we assigned and the purchasers assumed certain leases of major equipment used in the divested plants and operations of United States Steel. In the event of a default by any of the purchasers, United States Steel has assumed these obligations; however, we remain primarily obligated for payments under these leases.

Of the $420 million present value of net minimum capital lease payments, $37 million was related to obligations assumed by United States Steel under the Financial Matters Agreement.

Operating lease rental expense was:

(In millions)	2010	2009	2008
Minimum rental[a]	$ 241	$ 238	$ 245
Contingent rental	22	19	22
Sublease rentals	(2)	-	-
Net rental expense	$ 261	$ 257	$ 267

[a] Excludes $16 million, $3 million and $5 million paid by United States Steel in 2010, 2009 and 2008 on assumed leases.

24. Commitments and Contingencies

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance. At December 31, 2010 and 2009, accrued liabilities for remediation totaled $119 million and $116 million. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed. Receivables for recoverable costs from certain states, under programs to assist companies in clean-up efforts related to underground storage tanks at retail marketing outlets, were $56 million and $59 million at December 31, 2010 and 2009.

Guarantees – We have provided certain guarantees, direct and indirect, of the indebtedness of other companies. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements. In addition to these financial guarantees, we also have various performance guarantees related to specific agreements.

Guarantees related to indebtedness of equity method investees – We hold interests in an offshore oil port, LOOP LLC, and a crude oil pipeline system, LOCAP LLC. Both LOOP LLC and LOCAP LLC have secured various project financings with throughput and deficiency agreements. Under the agreements, we are required to advance funds if the investees are unable to service their debt. Any such advances are considered prepayments of future transportation charges. The terms of the agreements vary but tend to follow the terms of the underlying debt. Our maximum potential undiscounted payments under these agreements totaled $172 million as of December 31, 2010.

We hold an interest in a refined products pipeline through our investment in Centennial, and have guaranteed the repayment of Centennial's outstanding balance under a Master Shelf Agreement which expires in 2024. The guarantee arose in order for Centennial to obtain adequate financing. Our maximum potential undiscounted payments under this agreement totaled $55 million as of December 31, 2010.

Other guarantees – We have entered into other guarantees with maximum potential undiscounted payments totaling $188 million as of December 31, 2010, which consist primarily of leases of corporate assets containing general lease indemnities and guaranteed residual values, a commitment to contribute cash to an equity method investee for certain catastrophic events in lieu of procuring insurance coverage, a legal indemnification, a performance guarantee and a long-term transportation services agreement.

Existing guarantees of our subsidiaries' performance issued to Irish government entities remain in place after the 2009 sales until the purchasers issue similar guarantees to replace them. The guarantees, related to asset retirement obligations, have been indemnified by the purchasers. Our maximum potential undiscounted payments under these guarantees as of December 31, 2010 are $104 million.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain cokemaking facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $110 million as of December 31, 2010.

In October, 2010, upon acquiring a position in four exploration blocks in the Kurdistan Region of Iraq, we indemnified the Kurdistan Regional Government ("KRG") against any negative tax effects related to certain payments we are obligated to make to the KRG. As of December 31, 2010, some of those payments have been made, no related taxes have been assessed, and neither is there any history of such payments being taxed. Given the lack of history of tax assessment against such payments, and because certain of our future payments to the KRG are not quantifiable, a maximum potential undiscounted payments cannot be calculated.

General guarantees associated with dispositions – Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2010 and 2009, our contract commitments to acquire property, plant and equipment totaled $2,650 million and $2,938 million.

25. Subsequent Event

On January 13, 2011, the Board of Directors of Marathon Oil Corporation ("Marathon") announced that it has approved moving forward with plans to spin off Marathon's downstream (Refining, Marketing and Transportation) business, resulting in two independent, energy companies: Marathon Petroleum Corporation ("MPC") and Marathon Oil Corporation ("MRO"). To effect the spin-off, Marathon intends to distribute one share of MPC for every two shares of Marathon held at a record date to be determined. The transaction is expected to be effective June 30, 2011, with distribution of MPC shares shortly thereafter. A tax ruling request was submitted to the IRS regarding the tax-free nature of the spin-off and Marathon anticipates a response during the second quarter of 2011.

On February 1, 2011, MPC, currently a wholly owned subsidiary of Marathon, completed a private placement of three series of Senior Notes aggregating $3 billion (the "Notes"). The following table details information about each of the three series of Senior Notes:

(In millions)	
3.500% notes due March 1, 2016	$ 750
5.125% notes due March 1, 2021	1,000
6.500% notes due March 1, 2041	1,250
	$ 3,000

The Notes are intended to establish a minimum $750 million initial cash balance for MPC upon completion of the spin-off. All cash above that level will be used to repay existing intercompany debt with Marathon, and any remaining proceeds will be distributed to Marathon on or before June 30, 2011. The Notes are unsecured and unsubordinated obligations of MPC which are guaranteed by Marathon on a senior unsecured basis. Marathon's guarantees will terminate upon completion of the spin-off.

The holders of the Notes are entitled to the benefits of a registration rights agreement. Within 360 days, MPC and MRO will be obligated to use commercially reasonable efforts to file a registration statement with respect to a registered exchange offer to exchange the Notes for new notes that are guaranteed by MRO, if applicable, with terms substantially identical in all material respects to the Notes. Alternatively, if the exchange offer cannot be completed, we will be required to file a shelf registration statement to cover resale of the Notes under the Securities Act. If we do not comply with these obligations, we will be required to pay additional interest on the Notes. The additional interest shall accrue on the principal amount of the Notes at a rate of 0.25 per annum, which rate will be increased by an additional 0.25 percent per annum for each subsequent 90-day period that such additional interest continues to accrue, provided that the rate at which such additional interest accrues may not exceed 1.00 percent per annum. Marathon's obligations under the registration rights agreement will terminate upon termination of the Marathon guarantees in connection with the completion of the spin-off.

On January 27, 2011, Marathon commenced cash tender offers for certain specified series of outstanding debt, including that of its wholly owned subsidiary, Marathon Oil Canada Corporation (formerly known as Western Oil Sands Inc.). The tender offers are for any and all of four series of outstanding notes and a maximum of $500 million in aggregate principal amount of three additional series of Marathon's outstanding notes. In the any and all offer, $1.2 billion in aggregate principal amount of notes was tendered and accepted with a settlement date of February 10, 2011. In the maximum tender offer, $1.2 billion in aggregate principal amount of notes was tendered, of which $500 million was accepted, and settled on February 25, 2011.

In February 2011, Marathon gave notice in accordance with the make whole call provisions of the respective indentures that we will redeem $798 million in addition to the $1.2 billion any and all offer and the $500 million maximum tender offer, for a total principal amount of $2.5 billion to be redeemed by the end of the first quarter of 2011.

Selected Quarterly Financial Data (Unaudited)

(In millions, except per share data)	2010 [a] 1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	2009 [a] 1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$ 15,715	$ 18,238	$ 18,244	$ 20,124	$ 10,143	$ 13,001	$ 14,326	$ 15,817
Income from operations	1,000	1,571	1,506	1,240	538	1,042	1,017	993
Income from continuing operations	457	709	696	706	265	328	392	199
Discontinued operations[b]	-	-	-	-	17	85	21	156
Net income	457	709	696	706	282	413	413	355
Net income per share:								
– Basic	$ 0.64	$ 1.00	$ 0.98	$ 0.99	$ 0.40	$ 0.58	$ 0.58	$ 0.50
– Diluted	$ 0.64	$ 1.00	$ 0.98	$ 0.99	$ 0.40	$ 0.58	$ 0.58	$ 0.50
Dividends paid per share	$ 0.24	$ 0.25	$ 0.25	$ 0.25	$ 0.24	$ 0.24	$ 0.24	$ 0.24

(a) We have revised prior period revenues as discussed in Note 1 to the consolidated financial statements. Revenue was reduced by $155 million in the first quarter, $212 million in the second quarter and $198 million in the third quarter of 2010. Revenue was reduced by $33 million in the first quarter, $37 million in the second quarter, $37 million in the third quarter and $76 million in fourth quarter of 2009. Consolidated income did not change because an offsetting amount is in cost of revenues. The net amount of these entries was recorded in cost of sales and therefore had no impact on segment income.

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

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the United States; Europe, which primarily includes activities in the United Kingdom, Norway and Poland; Equatorial Guinea ("EG"); Other Africa, which primarily includes activities in Angola and Libya; Canada; and Other International ("Other Int'l"), which includes activities in Indonesia and the Iraqi Kurdistan Region. Discontinued operations ("Disc Ops") represent Marathon's Irish and Gabonese oil exploration and production businesses that were sold in 2009.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil is a highly technical process, which is based upon several underlying assumptions that are subject to change. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1 – Business.

(Millions of barrels)	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Liquid Hydrocarbons							
Proved developed and undeveloped reserves:							
Beginning of year - 2008	166	-	150	210	115	641	9
Revisions of previous estimates	3	-	4	7	(1)	13	(3)
Improved recovery	1	-	-	-	-	1	-
Extensions, discoveries and other additions	31	-	-	11	11	53	-
Production[c]	(23)	-	(15)	(17)	(20)	(75)	(2)
Sales of reserves in place	-	-	-	-	(1)	(1)	-
End of year - 2008	178	-	139	211	104	632	4
Revisions of previous estimates	-	-	(2)	3	19	20	2
Extensions, discoveries and other additions	21	-	-	31	12	64	
Production[c]	(23)	-	(15)	(17)	(33)	(88)	(2)
Sales of reserves in place	(6)	-	-	-	-	(6)	(4)
End of year - 2009	170	-	122	228	102	622	-
Revisions of previous estimates	(3)	-	10	-	23	30	-
Purchases of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	30	-	-	28	8	66	-
Production[c]	(25)	-	(13)	(17)	(34)	(89)	-
End of year - 2010	173	-	119	239	99	630	-
Proved developed reserves:							
Beginning of year - 2008	135	-	113	183	32	463	8
End of year - 2008	137	-	99	193	81	510	4
End of year - 2009	120	-	83	186	87	476	-
End of year - 2010	124	-	86	180	89	479	-
Proved undeveloped reserves:							
Beginning of year - 2008	31	-	37	27	83	178	1
End of year - 2008	41	-	40	18	23	122	-
End of year - 2009	50	-	39	42	15	146	-
End of year - 2010	49	-	33	59	10	151	-

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Natural Gas *(billions of cubic feet)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2008	1,007	-	1,951	110	238	3,306	144
Revisions of previous estimates	79	-	49	-	(51)	77	-
Extensions, discoveries and other additions	165	-	-	-	30	195	-
Production[c]	(164)	-	(134)	(1)	(48)	(347)	(12)
Sales of reserves in place	(2)	-	-	-	(10)	(12)	-
End of year - 2008	1,085	-	1,866	109	159	3,219	132
Revisions of previous estimates	(139)	-	(23)	-	(10)	(172)	-
Extensions, discoveries and other additions	80	-	-	-	2	82	-
Production[c]	(146)	-	(155)	(2)	(42)	(345)	(6)
Sales of reserves in place	(60)	-	-	-	-	(60)	(126)
End of year - 2009	820	-	1,688	107	109	2,724	-
Revisions of previous estimates	16	-	111	(1)	35	161	-
Purchases of reserves in place	1		-	-	-	1	
Extensions, discoveries and other additions	61	-	-	-	4	65	-
Production[c]	(133)	-	(148)	(1)	(32)	(314)	-
Sales of reserves in place	(20)	-	-	-	-	(20)	-
End of year - 2010	745	-	1,651	105	116	2,617	-
Proved developed reserves:							
Beginning of year - 2008	761	-	1,405	110	127	2,403	46
End of year - 2008	839	-	1,273	109	95	2,316	34
End of year - 2009	652	-	1,102	107	50	1,911	-
End of year - 2010	591	-	1,186	104	43	1,924	-
Proved undeveloped reserves:							
Beginning of year- 2008	246	-	546	-	111	903	98
End of year - 2008	246	-	593	-	64	903	98
End of year - 2009	168	-	586	-	59	813	-
End of year - 2010	154	-	465	1	73	693	-
Synthetic crude oil *(millions of barrels)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
Revisions of previous estimates	-	603	-	-	-	603	-
End of year - 2009	-	603	-	-	-	603	-
Revisions of previous estimates	-	(22)	-	-	-	(22)	-
Production	-	(9)	-	-	-	(9)	-
End of year - 2010	-	572	-	-	-	572	-
Proved developed reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	392	-	-	-	392	-
End of year - 2010	-	433	-	-	-	433	-
Proved undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	211	-	-	-	211	-
End of year - 2010	-	139	-	-	-	139	-

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(millions of barrels of oil equivalent)	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Total Proved Reserves							
Proved developed and undeveloped reserves:							
Beginning of year - 2008	334	-	475	228	155	1,192	33
Revisions of previous estimates	15	-	12	7	(9)	25	(2)
Improved recovery	1	-	-	-	-	1	-
Extensions, discoveries and other additions	59	-	-	11	16	86	-
Production[c]	(50)	-	(37)	(17)	(28)	(132)	(5)
Sales of reserves in place	-	-	-	-	(3)	(3)	-
End of year - 2008	359	-	450	229	131	1,169	26
Revisions of previous estimates[d]	(22)	603	(6)	3	17	595	1
Extensions, discoveries and other additions	34	-	-	31	13	78	-
Production[c]	(48)	-	(41)	(17)	(41)	(147)	(2)
Sales of reserves in place	(16)	-	-	-	-	(16)	(25)
End of year - 2009	307	603	403	246	120	1,679	-
Revisions of previous estimates	(1)	(22)	29	-	28	34	-
Purchases of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	40	-	-	28	9	77	-
Production[c]	(47)	(9)	(38)	(17)	(39)	(150)	-
Sales of reserves in place	(3)	-	-	-	-	(3)	-
End of year - 2010	297	572	394	257	118	1,638	-
Proved developed reserves:							
Beginning of year - 2008	262	-	347	202	52	863	16
End of year - 2008	277	-	312	211	96	896	10
End of year - 2009	229	392	267	204	95	1,187	-
End of year - 2010	222	433	284	198	96	1,233	-
Proved undeveloped reserves:							
Beginning of year - 2008	72	-	128	26	103	329	17
End of year - 2008	82	-	138	18	35	273	16
End of year - 2009	78	211	136	42	25	492	-
End of year- 2010	75	139	110	59	22	405	-

(a) Synthetic crude oil proved reserves were added as of December 31, 2009.

(b) Consists of estimated reserves from properties governed by production sharing contracts.

(c) Excludes the resale of purchased natural gas utilized in reservoir management.

(d) Volumes for Canada are after 10 million barrels of synthetic crude oil production in 2009.

The most significant impact of adopting the SEC's updated regulations on oil and gas producing activities in 2009 was the addition of 603 mmbbl of synthetic crude oil to our reserves.

Information on Proved Bitumen Reserves

Prior to 2009, we reported reserves related to our oil sands mining operations in Alberta, Canada, as bitumen, which were reported separately from other reserves since bitumen reserves were not considered related to oil and gas producing activities by the SEC. Reserve quantities under the updated SEC regulations include synthetic crude oil (bitumen after upgrading) reserves and are included in the Estimated Quantities of Proved Oil and Gas Reserves for 2009. During 2009, activity related to our bitumen reserves included purchase of reserves of 168 million barrels ("mmbbl") of bitumen and production of 9 mmbbl of bitumen.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

(Millions of barrels)	Continuing Operations
Proved Bitumen Reserves:	
Beginning of year - 2008	421
Revisions	(30)
Extensions, discoveries and other additions	6
Production	(9)
End of year - 2008	388
Purchase of reserves in place	168
Revisions	(17)
Production	(9)
Impact of new regulations[a]	(530)
End of year - 2009	-

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	December 31,						
(In millions)	United States	Canada[a]	EG	Other Africa	Europe	Other Int'l	Total
2010 Capitalized costs:							
Proved properties	$ 12,008	$ 8,362	$ 1,518	$ 1,437	$ 8,032	$ 24	$ 31,381
Unproved properties	1,450	1,626	24	277	46	122	3,545
Total	13,458	9,988	1,542	1,714	8,078	146	34,926
Accumulated depreciation, depletion and amortization:							
Proved properties	7,049	381	625	122	5,927	1	14,105
Unproved properties	325	-	-	9	-	8	342
Total	7,374	381	625	131	5,927	9	14,447
Net capitalized costs	$ 6,084	$ 9,607	$ 917	$ 1,583	$ 2,151	$ 137	$ 20,479
2009 Capitalized costs:							
Proved properties	$ 10,927	$ 7,510	$ 1,521	$ 1,505	$ 7,790	$ 3	$ 29,256
Unproved properties	1,258	1,544	24	404	68	19	3,317
Total	12,185	9,054	1,545	1,909	7,858	22	32,573
Accumulated depreciation, depletion and amortization:							
Proved properties	6,128	280	516	85	5,230	1	12,240
Unproved properties	60	-	-	9	1	8	78
Total	6,188	280	516	94	5,231	9	12,318
Net capitalized costs	$ 5,997	$ 8,774	$ 1,029	$ 1,815	$ 2,627	$ 13	$ 20,255

[a] 2010 and 2009 include amounts related to our oil sands mining operations.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Costs Incurred for Property Acquisition, Exploration and Development (a)

(In millions)	United States	Canada[b]	EG	Other Africa	Europe	Other Int'l	Continuing Operations	Disc Ops	Total
2010 Property acquisition:									
Proved	$ 1	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ 1
Unproved	320	-	-	1	2	103	426	-	426
Exploration	423	10	1	41	43	153	671	-	671
Development	1,032	889	13	315	465	-	2,714	-	2,714
Total	$ 1,776	$ 899	$ 14	$ 357	$ 510	$ 256	$ 3,812	$ -	$ 3,812
2009 Property acquisition:									
Proved	$ -	$ 11	$ -	$ -	$ -	$ -	$ 11	$ 15	$ 26
Unproved	127	1	-	6	-	2	136	-	136
Exploration	271	11	-	127	81	29	519	-	519
Development	1,150	976	23	266	354	-	2,769	64	2,833
Total	$ 1,548	$ 999	$ 23	$ 399	$ 435	$ 31	$ 3,435	$ 79	$ 3,514
2008 Property acquisition:									
Proved	$ 3	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ 3
Unproved	397	-	-	8	-	7	412	-	412
Exploration	738	31	1	155	56	85	1,066	1	1,067
Development	1,072	-	30	141	516	-	1,759	165	1,924
Total	$ 2,210	$ 31	$ 31	$ 304	$ 572	$ 92	$ 3,240	$ 166	$ 3,406

(a) Includes costs incurred whether capitalized or expensed.

(b) 2010 and 2009 include amounts related to our oil sands mining operations.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

(In millions)	United States	Canada[a]	EG	Other Africa	Europe	Other Int'l	Total
2010 Revenues and other income:							
Sales	$ 1,635	$ 642	$ 11	$ 1,473	$ 697	$ -	$ 4,458
Transfers	887	50	701	-	2,319	-	3,957
Other income[c]	(406)	-	-	812	(64)	-	342
Total revenues and other income	2,116	692	712	2,285	2,952	-	8,757
Expenses:							
Production costs	(815)	(596)	(108)	(70)	(297)	-	(1,886)
Exploration expenses	(275)	(5)	(21)	(47)	(32)	(118)	(498)
Depreciation, depletion and amortization[d]	(1,040)	(109)	(110)	(36)	(687)	-	(1,982)
Administrative expenses	(52)	(9)	(1)	2	(20)	(10)	(90)
Total expenses	(2,182)	(719)	(240)	(151)	(1,036)	(128)	(4,456)
Results before income taxes	(66)	(27)	472	2,134	1,916	(128)	4,301
Income tax (provision) benefit	26	7	(187)	(1,647)	(658)	46	(2,413)
Results of continuing operations	$ (40)	$ (20)	$ 285	$ 487	$ 1,258	$ (82)	$ 1,888
2009 Revenues and other income:							
Sales[b]	$ 1,426	$ 499	$ 23	$ 1,146	$ 699	$ -	$ 3,793
Transfers	437	100	587	-	1,678	-	2,802
Other income[c]	185	-	-	-	13	-	198
Total revenues and other income	2,048	599	610	1,146	2,390	-	6,793
Expenses:							
Production costs	(763)	(371)	(108)	(62)	(289)	-	(1,593)
Exploration expenses	(153)	(16)	-	(73)	(37)	(28)	(307)
Depreciation, depletion and amortization[d]	(846)	(126)	(115)	(37)	(736)	-	(1,860)
Administrative expenses	(53)	(9)	(1)	(3)	(13)	(22)	(101)
Total expenses	(1,815)	(522)	(224)	(175)	(1,075)	(50)	(3,861)
Results before income taxes	233	77	386	971	1,315	(50)	2,932
Income tax (provision) benefit	(76)	(17)	(112)	(770)	(678)	14	(1,639)
Results of continuing operations	$ 157	$ 60	$ 274	$ 201	$ 637	$ (36)	$ 1,293
Results of discontinued operations	$ -	$ -	$ -	$ 194	$ 79	$ -	$ 273
2008 Revenues and other income:							
Sales[b]	$ 2,619	$ -	$ 28	$ 1,858	$ 1,164	$ -	$ 5,669
Transfers	547	-	995	-	1,062	-	2,604
Other income[c]	1	-	-	-	254	-	255
Total revenues and other income	3,167	-	1,023	1,858	2,480	-	8,528
Expenses:							
Production costs	(845)	-	(96)	(41)	(340)	-	(1,322)
Exploration expenses	(238)	(25)	(2)	(45)	(87)	(92)	(489)
Depreciation, depletion and amortization[d]	(671)	-	(102)	(35)	(475)	(1)	(1,284)
Administrative expenses	(49)	(1)	(1)	(15)	(16)	(36)	(118)
Total expenses	(1,803)	(26)	(201)	(136)	(918)	(129)	(3,213)
Results before income taxes	1,364	(26)	822	1,722	1,562	(129)	5,315
Income tax (provision) benefit	(513)	6	(280)	(1,550)	(551)	44	(2,844)
Results of continuing operations	$ 851	$ (20)	$ 542	$ 172	$ 1,011	$ (85)	$ 2,471
Results of discontinued operations	$ -	$ -	$ -	$ 117	$ 28	$ -	$ 145

(a) 2010 and 2009 include amounts related to our oil sands mining operations.

(b) Excludes noncash effects of changes in the fair value of certain natural gas sales contracts in the United Kingdom which expired September 2009.

(c) Includes net gain on disposal of assets.

(d) Includes long-lived asset impairments.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of continuing operations for oil and gas producing activities to segment income:

(In millions)	2010	2009	2008
Results of continuing operations	$ 1,888	$ 1,293	$ 2,471
Items not included in results of continuing oil and gas operations, net of tax:			
Marketing income and technology costs	(12)	(21)	27
Income from equity method investments	167	110	201
Other third-party income[(a)]	(5)	9	26
Other	(2)	(4)	(6)
Items not allocated to segment income, net of tax:			
Gain on asset disposition	(449)	(122)	(163)
Long-lived asset impairments	303	-	-
Segment income (loss) not included in results of continuing oil and gas operations:			
Oil Sands Mining[(b)]	N/A	N/A	258
Refining, Marketing and Transportation	682	464	1,179
Integrated Gas	142	90	302
Segment income	$ 2,714	$ 1,819	$ 4,295

(a) Includes revenues, net of associated costs and income taxes, from activities that support our production operations, which may include processing or transportation of third-party production and the purchase and subsequent resale of natural gas utilized for reservoir management.

(b) 2010 and 2009 Oil Sands Mining segment income is included in the Results of Operations for Oil and Gas Producing Activities.

Standardized Measure of Discounted Future Net Cash Flows

	December 31,					
(In millions)	United States	Canada	EG	Other Africa	Europe	Total
2010						
Future cash inflows	$ 15,349	$ 41,901	$ 5,366	$ 20,815	$ 8,800	$ 92,231
Future production and administrative costs	(6,878)	(21,675)	(1,469)	(997)	(2,274)	(33,293)
Future development costs	(2,084)	(9,688)	(441)	(907)	(1,535)	(14,655)
Future income tax expenses	(1,726)	(1,821)	(1,208)	(17,201)	(3,602)	(25,558)
Future net cash flows	$ 4,661	$ 8,717	$ 2,248	$ 1,710	$ 1,389	$ 18,725
10 percent annual discount for estimated timing of cash flows	(2,008)	(6,168)	(795)	(824)	(166)	(9,961)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,653	$ 2,549	$ 1,453	$ 886	$ 1,223	$ 8,764
2009						
Future cash inflows	$ 12,094	$ 32,207	$ 4,620	$ 14,974	$ 6,901	$ 70,796
Future production and administrative costs	(6,796)	(21,044)	(1,514)	(876)	(2,373)	(32,603)
Future development costs	(1,362)	(6,715)	(462)	(677)	(1,119)	(10,335)
Future income tax expenses	(923)	(60)	(935)	(12,419)	(1,768)	(16,105)
Future net cash flows	$ 3,013	$ 4,388	$ 1,709	$ 1,002	$ 1,641	$ 11,753
10 percent annual discount for estimated timing of cash flows	(1,041)	(3,658)	(625)	(571)	(167)	(6,062)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,972	$ 730	$ 1,084	$ 431	$ 1,474	$ 5,691
2008						
Future cash inflows	$ 11,295	$ -	$ 3,316	$ 8,952	$ 5,578	$ 29,141
Future production and administrative costs	(6,045)	-	(1,525)	(666)	(2,130)	(10,366)
Future development costs	(2,673)	-	(436)	(172)	(1,690)	(4,971)
Future income tax expenses	(443)	-	(429)	(7,422)	(64)	(8,358)
Future net cash flows	$ 2,134	$ -	$ 926	$ 692	$ 1,694	$ 5,446
10 percent annual discount for estimated timing of cash flows	(703)	-	(352)	(330)	(26)	(1,411)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,431	$ -	$ 574	$ 362	$ 1,668	$ 4,035
Standardized measure of discounted future net cash flows relating to discontinued operations	$ -	$ -	$ -	$ 20	$ 264	$ 284

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

(In millions)	2010	2009	2008
Sales and transfers of oil and gas produced, net of production and administrative costs	$ (6,330)	$ (4,876)	$ (6,863)
Net changes in prices and production and administrative costs related to future production	9,843	4,840	(18,683)
Extensions, discoveries and improved recovery, less related costs	1,268	1,399	663
Development costs incurred during the period	2,723	2,786	1,774
Changes in estimated future development costs	(2,475)	(3,641)	(1,436)
Revisions of previous quantity estimates	1,117	5,110	85
Net changes in purchases and sales of minerals in place	(20)	(159)	(13)
Accretion of discount	1,348	787	2,724
Net change in income taxes	(4,651)	(4,441)	12,633
Timing and other	250	(149)	184
Net change for the year	3,073	1,656	(8,932)
Beginning of the year	5,691	4,035	12,967
End of year	$ 8,764	$ 5,691	$ 4,035
Net change for the year from discontinued operations	$ -	$ -	$ 284

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions)	December 31, 2010	2009	2008
Segment Income (Loss)			
Exploration and Production			
United States	$ 250	$ 55	$ 869
International	1,690	1,166	1,687
E&P segment	1,940	1,221	2,556
Oil Sands Mining	(50)	44	258
Integrated Gas	142	90	302
Refining, Marketing and Transportation	682	464	1,179
Segment income	2,714	1,819	4,295
Items not allocated to segments, net of income taxes	(146)	(356)	(767)
Net income	$ 2,568	$ 1,463	$ 3,528
Capital Expenditures[(a)]			
Exploration and Production			
United States	$ 1,528	$ 1,420	$ 2,036
International	946	742	935
E&P segment	2,474	2,162	2,971
Oil Sands Mining	874	1,115	1,038
Integrated Gas	2	2	4
Refining, Marketing and Transportation	1,175	2,570	2,954
Discontinued Operations[(b)]	-	81	142
Corporate	46	42	37
Total	$ 4,571	$ 5,972	$ 7,146
Exploration Expenses			
United States	$ 275	$ 153	$ 238
International	223	154	251
Total	$ 498	$ 307	$ 489

(a) Capital expenditures include changes in accruals.

(b) Our businesses in Ireland and Gabon were sold in 2009. These businesses have been reflected as discontinued operations in 2009 and 2008.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

		2010		2009		2008
E&P Operating Statistics						
Net Liquid Hydrocarbon Sales (mbpd)						
United States		70		64		63
Europe		92		92		55
Africa		83		87		87
Total International		175		179		142
Worldwide Continuing Operations		245		243		205
Discontinued Operations		-		5		6
Worldwide		245		248		211
Natural gas liquids included in above		16		19		20
Natural Gas Sales (mmcfd)[c]						
United States		364		373		448
Europe		105		138		161
Africa		409		430		370
Total International		514		568		531
Worldwide Continuing Operations		878		941		979
Discontinued Operations		-		17		37
Worldwide		878		958		1,016
Total Worldwide Sales (mboepd)						
Continuing Operations		391		400		369
Discontinued Operations		-		7		12
Worldwide		391		407		381
Average Realizations[d]						
Liquid Hydrocarbons (per bbl)						
United States	$	72.30	$	54.67	$	86.68
Europe		81.95		64.46		90.60
Africa		71.71		53.91		89.85
Total International		77.11		59.31		90.14
Worldwide Continuing Operations		75.73		58.09		89.07
Discontinued Operations		-		56.47		96.41
Worldwide	$	75.73	$	58.06	$	89.29
Natural Gas (per mcf)						
United States	$	4.71	$	4.14	$	7.01
Europe		7.10		4.90		7.67
Africa[e]		0.25		0.25		0.25
Total International		1.65		1.38		2.50
Worldwide Continuing Operations		2.91		2.47		4.56
Discontinued Operations		-		8.54		9.62
Worldwide	$	2.91	$	2.58	$	4.75
OSM Operating Statistics						
Net Synthetic Crude Sales (mbpd) [f]		29		32		32
Synthetic Crude Average Realization (per bbl)[d]	$	71.06	$	56.44	$	91.90
Net Proved Bitumen Reserves at year-end (mmbbl)[g]		N/A		N/A		388

(c) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd, 22 mmcfd and 32 mmcfd for the years 2010, 2009 and 2008.

(d) Excludes gains and losses on derivative instruments.

(e) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and 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.

(f) Includes blendstocks.

(g) Prior to December 31, 2009, reserves related to oil sand mining were not included in the SEC's definition of oil and gas producing activities; therefore, bitumen reserves were reported separately for the OSM segment. See the Proved Reserves section of the supplemental statistics for 2009 information.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions, except as noted)	2010	2009	2008
Proved Reserves			
Net Proved Reserves at year-end (developed and undeveloped)			
Liquid Hydrocarbons (mmbbl)			
United States	173	170	178
International	457	452	454
Worldwide Continuing Operations	630	622	632
Discontinued Operations	-	-	4
Worldwide	630	622	636
Natural Gas (bcf)			
United States	745	820	1,085
International	1,872	1,904	2,134
Worldwide Continuing Operations	2,617	2,724	3,219
Discontinued Operations	-	-	132
Worldwide	2,617	2,724	3,351
Synthetic Crude Oil (mmbbls)[h]			
Canada	572	603	N/A
Total Proved Reserves (mmboe)	1,638	1,679	1,195
IG Operating Statistics			
Net Sales (mtpd) [i]			
LNG	6,859	6,642	6,285
Methanol	1,049	1,192	975
RM&T Operating Statistics			
Refinery Runs (mbpd)			
Crude oil refined	1,173	957	944
Other charge and blend stocks	162	196	207
Total	1,335	1,153	1,151
Refined Product Yields (mbpd)			
Gasoline	726	669	609
Distillates	409	326	342
Propane	24	23	22
Feedstocks and special products	97	62	96
Heavy fuel oil	24	24	24
Asphalt	76	66	75
Total	1,356	1,170	1,168
Refined Products Sales Volumes (mbpd) [j]	1,585	1,378	1,352
Refining and Wholesale Marketing Gross Margin (per gallon) [k]	$ 0.0706	$ 0.0610	$ 0.1166
Speedway			
Retail outlets	1,358	1,603	1,617
Gasoline and distillate sales (millions of gallons)	3,300	3,232	3,215
Gasoline and distillate gross margin (per gallon)	$ 0.1369	$ 0.1141	$ 0.1387
Merchandise sales	$ 3,195	$ 3,109	$ 2,838
Merchandise gross margin	$ 789	$ 775	$ 716

(h) Beginning December 31, 2009, under revised SEC regulations, reserves related to oil sands mining are reported as synthetic crude oil (bitumen after upgrading), in combination with oil and gas producing activities.

(i) 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.

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

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

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-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.

Internal Control Over Financial Reporting

See Financial Statements and Supplementary Data – Management's Report on Internal Control over Financial Reporting and – Report of Independent Registered Public Accounting Firm. During the fourth quarter of 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.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning our directors required by this item is incorporated by reference to the material appearing under the heading "Election of Directors" in our Proxy Statement for the 2011 Annual Meeting of stockholders.

Our Board of Directors has established the Audit and Finance Committee and determined our "Audit Committee Financial Expert." The related information required by this item is incorporated by reference to the material appearing under the sub-heading "Audit and Finance Committee" located under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2011 Annual Meeting of Stockholders.

We have adopted a Code of Ethics for Senior Financial Officers. It is available on our website at http://www.marathon.com/Investor_Center/Corporate_Governance/Code_of_Ethics_for_Senior_Financial_Officers/.

Executive Officers of the Registrant

See Item 1. Business – Executive Officers of the Registrant for the names, ages and titles of our executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires that the Company's directors and executive officers, and persons who own more than ten percent of a registered class of the Company's equity securities, file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Form 4 or Form 5 with the Securities and Exchange Commission. Based solely on the Company's review of the reporting forms and written representations provided to the Company from the individuals required to file reports, the Company believes that each of its directors and executive officers has complied with the applicable reporting requirements for transactions in the Company's securities during the fiscal year ended December 31, 2010, except that Sylvia J. Kerrigan did not timely report 4,075 shares of Marathon common stock owned by her on a Form 3 filed on November 10, 2009. An amended Form 3 was filed on February 22, 2011 to correct the mistake.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the material appearing under the heading "Executive Compensation Tables and Other Information;" under the sub-headings "Compensation Committee" and "Compensation Committee Interlocks and Insider Participation" under the heading "The Board of Directors and Governance Matters;" and under the heading "Compensation Committee Report" in our Proxy Statement for the 2011 Annual Meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information concerning security ownership of certain beneficial owners and management required by this item is incorporated by reference to the material appearing under the headings "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in our Proxy Statement for the 2011 Annual Meeting of stockholders.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2010 with respect to shares of Marathon common stock that may be issued under our existing equity compensation plans:

- 2007 Incentive Compensation Plan (the "2007 Plan")
- 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.
- 1990 Stock Plan – No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

	Column (a)	Column (b)	Column (c)
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[c]	Number of securities remaining available for future issuance under equity compensation plans[a]
Equity compensation plans approved by stockholders	21,046,614 [a]	$ 34.12	17,259,280 [d]
Equity compensation plans not approved by stockholders	91,457 [b]	N/A	—
Total	21,138,071	N/A	17,259,280

(a) Includes the following:

- 13,959,197 stock options outstanding under the 2007 Plan;
- 6,373,258 stock options outstanding under the 2003 Plan and the net number of stock-settled SARs that could be issued from this Plan. The number of stock-settled SARs is based on the closing price of Marathon common stock on December 31, 2010 of $37.03 per share;
- 276,860 stock options and SARs outstanding under the 1990 Stock Plan;
- 272,095 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2007 Plan and the 2003 Plan; common stock units credited under the 2007 Plan and the 2003 Plan were 140,670 and 131,425;
- 165,204 restricted stock units granted to non-officers under the 2007 Plan and outstanding as of December 31, 2010.

In addition to the awards reported above 1,145,255 shares of restricted stock were issued and outstanding as of December 31, 2010, but subject to forfeiture restrictions under the 2007 Plan.

(b) Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon common stock in place of the common stock units.

(c) Weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2007 Plan. No more than 9,359,819 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, cancelled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the material appearing under the heading "Certain Relationships and Related Person Transactions," and under the sub-heading "Board and Committee Independence" under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2011 Annual Meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the material appearing under the heading "Information Regarding the Independent Registered Public Accounting Firm's Fees, Services and Independence" in our Proxy Statement for the 2011 Annual Meeting of stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this report regarding financial statements)

2. Financial Statement Schedules

   Financial statement schedules required under SEC rules but not included in this report are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits:

   Any reference made to USX Corporation in the exhibit listing that follows is a reference to the former name of Marathon Oil Corporation, a Delaware corporation and the registrant, and is made because the exhibit being listed and incorporated by reference was originally filed before July 2001, the date of the change in the registrant's name. References to Marathon Ashland Petroleum LLC or MAP are references to the entity now known as Marathon Petroleum Company LP.

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**						
2.1++	Amended and Restated Arrangement Agreement among Marathon Oil Corporation, Marathon Oil Canada Corporation (formerly known as 1339971 Alberta Ltd.), Western Oil Sands Inc. and WesternZagros Resources Inc., dated as of September 14, 2007	S-3ASR	2.7	10/17/2007	333-146772		
2.2++	Amending Agreement among Marathon Oil Corporation, Marathon Oil Canada Corporation (formerly known as 1339971 Alberta Ltd.), Western Oil Sands Inc. and WesternZagros Resources Inc., dated as of October 15, 2007	S-3ASR	2.8	10/17/2007	333-146772		
2.3++	Plan of Arrangement under Section 193 of the Business Corporations Act (Alberta)	S-3ASR	2.9	10/17/2007	333-146772		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
3	**Articles of Incorporation and Bylaws**						
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	8-K	3.1	4/25/2007			
3.2	By-Laws of Marathon Oil Corporation					X	
3.3	Specimen of Common Stock Certificate	8-K	3.3	5/14/2007			
4	**Instruments Defining the Rights of Security Holders, Including Indentures**						
4.1	Five Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, ABN Ambro Bank N.V., Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-K	4.1	2/26/2010			
4.2	Amendment No. 1 dated as of May 4, 2006 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	5/8/2006			
4.3	Amendment No. 2 dated as of May 7, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	8/7/2007			
4.4	Amendment No. 3 dated as of October 4, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	11/7/2007			
4.5	Amendment No. 4 dated as of April 3, 2008 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.2	5/9/2008			
4.6	Indenture dated February 26, 2002 between Marathon and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon	S-3	4.4	7/26/2007	333-144874		
4.7	Indenture dated February 1, 2011 between Marathon Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A. as Trustee, relating to debt securities of Marathon Petroleum Corporation	8-K	4.1	2/1/2011			

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
4.8	Guarantee Agreement of Marathon dated February 1, 2011	8-K	4.4	2/1/2011			
	Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon. Marathon hereby agrees to furnish a copy of any such instrument to the Commission upon its request						
10	**Material Contracts**						
10.1	Financial Matters Agreement between USX Corporation and United States Steel LLC (converted into United States Steel Corporation) dated as of December 31, 2001	10-K	10.2	2/29/2008			
10.2	Registration Rights Agreement among Marathon Petroleum Corporation, Marathon Oil Corporation and Morgan Stanley & Co. Incorporated and J.P. Morgan Securities LLC, as representatives of the initial purchasers	8-K	10.1	2/1/2011			
10.3	Marathon Oil Corporation 2007 Incentive Compensation Plan (incorporated by reference to Appendix I to Marathon Oil Corporation's Definitive Proxy Statement on Schedule 14A filed on March 14, 2007	14A	App. I	3/14/2007			
10.4	Form of Non-Qualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-Q	10.2	8/7/2007			
10.5	Form of Non-Qualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective February 24, 2010					X	
10.6	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-Q	10.3	8/7/2007			
10.7	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective February 24, 2010					X	
10.8	Form of Performance Unit Award Agreement (2007-2009 Performance Cycle) for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective May 30, 2007	10-Q	10.4	8/7/2007			

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.9	Form of Performance Unit Award Agreement (2007-2009 Performance Cycle) for Officers granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan, effective February 24, 2010					X	
10.10	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts					X	
10.11	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010			
10.12	First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated) Effective January 1, 2002	10-Q	10.1	11/7/2008			
10.13	First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated Effective January 1, 2002	10-Q	10.2	11/7/2008			
10.14	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors	10-K	10.14	2/27/2009			
10.15	Form of Non-Qualified Stock Option Grant for MAP officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002	10-Q	10.3	11/3/2004			
10.16	Form of Non-Qualified Stock Option Grant for MAP officers granted under Marathon Oil Corporation's 1990 Stock Plan, as amended and restated effective January 1, 2002	10-K	10.14	3/6/2006			
10.17	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.14	2/26/2010			
10.18	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.15	2/26/2010			
10.19	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.16	2/26/2010			

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.20	Form of Non-Qualified Stock Option Award Agreement for MAP officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.17	2/26/2010			
10.21	Form of Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.18	2/26/2010			
10.22	Form of Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.19	2/26/2010			
10.23	Form of Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.2	2/26/2010			
10.24	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan	10-K	10.21	2/26/2010			
10.25	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010			
10.26	Form of Performance Unit Award Agreement (2005-2007 Performance Cycle) granted under Marathon Oil Corporation's 2003 Incentive Compensation Plan	10-K	10.23	2/26/2010			
10.27	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan	10-K	10.24	2/26/2010			
10.28	Form of Performance Unit Award Agreement (2010-2012 Performance Cycle) granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan	10-K	10.25	2/26/2010			
10.29	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010			
10.30	Marathon Oil Company Excess Benefit Plan	10-K	10.27	2/27/2009			
10.31	Marathon Oil Company Deferred Compensation Plan	10-K	10.28	2/27/2009			
10.32	Marathon Petroleum Company LLC Excess Benefit Plan	10-K	10.29	2/27/2009			
10.33	Marathon Petroleum Company LLC Deferred Compensation Plan	10-K	10.3	2/27/2009			

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.34	Speedway SuperAmerica LLC Excess Benefit Plan	10-K	10.31	2/27/2009			
10.35	Executive Tax, Estate, and Financial Planning Program	10-K	10.32	2/27/2009			
10.36	EMRO Marketing Company Deferred Compensation Plan	10-K	10.33	2/27/2009			
10.37	Speedway SuperAmerica LLC Deferred Compensation Plan	10-K	10.34	2/27/2009			
10.38	Executive Change in Control Severance Benefits Plan	10-K	10.35	2/27/2009			
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/26/2010			
21.1	List of Significant Subsidiaries.					X	
23.1	Consent of Independent Registered Public Accounting Firm.					X	
23.2	Consent of GLJ Petroleum Consultants, independent petroleum engineers and geologists.					X	
23.3	Consent of Ryder Scott, independent petroleum engineers and geologists.					X	
23.4	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists					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	
99.1	Report of GLJ Petroleum Consultants, independent petroleum engineers and geologists.					X	
99.2	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists.	10-K/A	99.2	9/17/2010			
99.3	Summary report of audits performed by Ryder Scott, independent petroleum engineers and geologists.	10-K/A	99.3	9/17/2010			

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
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
101.DEF	XBRL Taxonomy Extension Definition Linkbase.						X

++ **Marathon agrees to furnish supplementally a copy of any omitted schedule to the United States Securities and Exchange Commission upon request**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

February 25, 2011

MARATHON OIL CORPORATION

By: /s/ MICHAEL K. STEWART

Michael K. Stewart
Vice President, Accounting and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 25, 2011 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ THOMAS J. USHER Thomas J. Usher	Chairman of the Board and Director
/s/ CLARENCE P. CAZALOT, JR. Clarence P. Cazalot, Jr.	President and Chief Executive Officer and Director
/s/ JANET F. CLARK Janet F. Clark	Executive Vice President and Chief Financial Officer
/s/ MICHAEL K. STEWART Michael K. Stewart	Vice President, Accounting and Controller
/s/ GREGORY H. BOYCE Gregory H. Boyce	Director
/s/ PIERRE BRONDEAU Pierre Brondeau	Director
/s/ DAVID A. DABERKO David A. Daberko	Director
/s/ WILLIAM L. DAVIS William L. Davis	Director
/s/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/s/ PHILIP LADER Philip Lader	Director
/s/ CHARLES R. LEE Charles R. Lee	Director
/s/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director
/s/ DENNIS H. REILLEY Dennis H. Reilley	Director
/s/ SETH E. SCHOFIELD Seth E. Schofield	Director
/s/ JOHN W. SNOW John W. Snow	Director

Corporate Information

Corporate Headquarters
5555 San Felipe Road
Houston, TX 77056-2723

Marathon Oil Corporation Web Site
www.marathon.com

Investor Relations Office
5555 San Felipe Road (77056-2723)
P.O. Box 3128 (77253-3128)
Houston, TX

Howard J. Thill, Vice President,
Investor Relations and Public Affairs
+1 713-296-4140

Chris C. Phillips, Manager, Investor Relations
+1 713-296-3213

Notice of Annual Meeting
The 2011 Annual Meeting of Stockholders will be held in Houston, Texas, on April 27, 2011.

Independent Accountants
PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, TX 77002-5678

Stock Exchange Listing
New York Stock Exchange

Common Stock Symbol
MRO

Stock Transfer Agent
Computershare
250 Royall Street
Canton, MA 02021
888-843-5542 (Toll free - U.S., Canada, Puerto Rico)
+1 781-575-4735 (non-U.S.)
web.queries@computershare.com

Dividends
Dividends on common stock, as declared by the Board of Directors, are normally paid on the 10th day of March, June, September and December.

Dividend Checks Not Received / Electronic Deposit
If you do not receive your dividend check on the appropriate payment date, we suggest that you wait at least 10 days after the payment date to allow for any delay in mail delivery. After that time, advise Computershare by phone or in writing to issue a replacement check. You may contact Computershare to authorize electronic deposit of your dividends into your bank account.

Dividend Reinvestment and Direct Stock Purchase Plan
The Dividend Reinvestment and Direct Stock Purchase Plan provides stockholders with a convenient way to purchase additional shares of Marathon Oil Corporation common stock without payment of any brokerage fees or service charges through investment of cash dividends or through optional cash payments. Stockholders of record can request a copy of the Plan Prospectus and an authorization form from Computershare. Beneficial holders should contact their brokers.

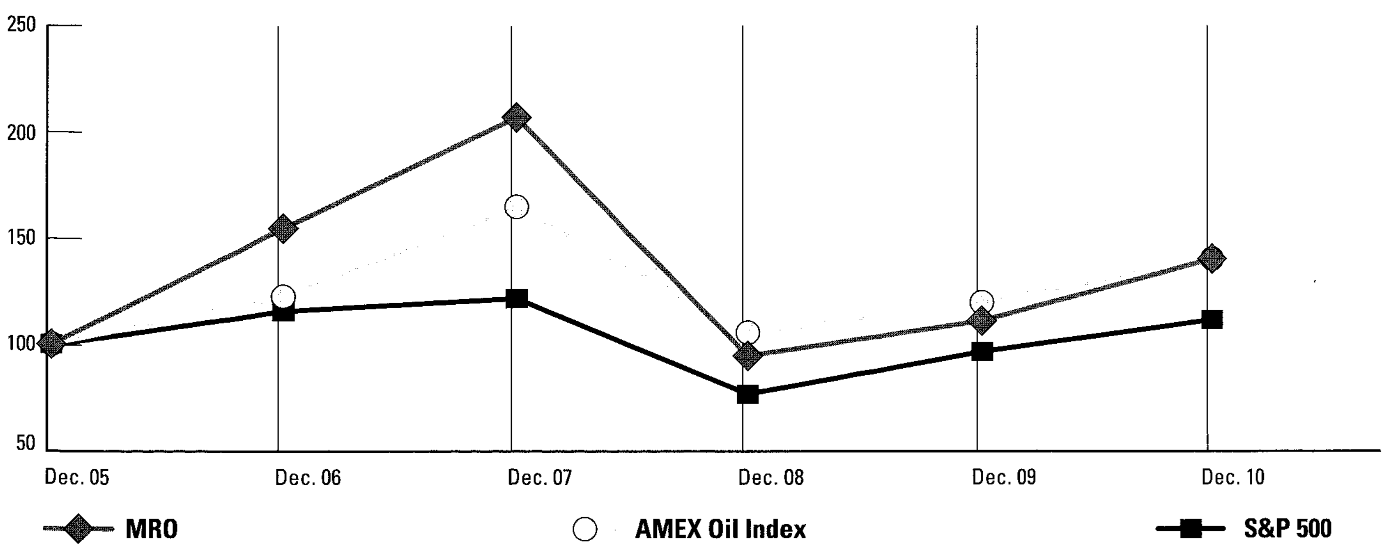
Lost Stock Certificate
If a stock certificate is lost, stolen or destroyed, notify Computershare in writing so that a stop transfer can be placed on the missing certificate. You will be required to obtain and pay for the cost of an indemnity bond. If you find the missing certificate, notify Computershare in writing immediately so that the stop transfer can be removed. To avoid loss, theft or destruction, we recommend that you keep your certificates in a safe place, such as a safe deposit box at your bank.

Taxpayer Identification Number
Federal law requires that each stockholder provide a certified Taxpayer Identification Number (TIN) for his/her stockholder account. For individual stockholders, your TIN is your Social Security Number. If you do not provide a certified TIN, Computershare may be required to withhold 28 percent for federal income taxes from your dividends.

Address Change
It is important that you notify Computershare immediately, by phone, in writing or by fax, when you change your address. Seasonal addresses can be entered for your account.

Stockholder Return Performance Graph
The line graph below compares the yearly change in cumulative total stockholder return for our common stock with the cumulative total return of the AMEX Oil Index and the Standard & Poor's 500 Stock Index.

Comparison of Cumulative Total Return on $100 Invested in Marathon Common Stock on December 31, 2005 vs. *S&P 500 and AMEX Oil Index



*Total return assumes reinvestment of dividends.

Cautionary Note and Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

The letter to stockholders contains forward-looking statements with respect to the AOSP expansion, the potential sale of our interest in the Gudrun project in Norway, the Detroit Heavy Oil Upgrading Project (DHOUP), and the possible spin-off of Marathon Petroleum Corporation. Factors that could potentially affect the AOSP expansion and DHOUP 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 our interest in Gudrun include Norwegian governmental approval and customary closing conditions. Some factors that could affect the possible spin-off of Marathon Petroleum Corporation include board approval, receipt of a private letter ruling from the IRS and a registration statement declared effective by the SEC. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements. In accordance with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, Marathon Oil Corporation has included in its attached Form 10-K for the year ended December 31, 2010, cautionary language identifying other important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.