NOBLE ENERGY INC
Form 10-Q
July 26, 2012

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2012

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	73-0785597
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100	
Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant's telephone number, including area code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller
reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company"

in Rule 12b-2 of the Exchange Act.

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

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

As of July 11, 2012, there were 177,827,784 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements
Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues				
Oil, Gas and NGL Sales	$934	$783	$1,970	$1,500
Income from Equity Method Investees	32	48	86	96
Other Revenues	—	11	—	33
Total	966	842	2,056	1,629
Costs and Expenses				
Production Expense	169	137	334	264
Exploration Expense	167	67	227	137
Depreciation, Depletion and Amortization	325	211	619	404
General and Administrative	96	82	193	164
Asset Impairments	73	131	73	137
Other Operating (Income) Expense, Net	(2)	(11)	10	18
Total	828	617	1,456	1,124
Operating Income	138	225	600	505
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	(276)	(143)	(180)	143
Interest, Net of Amount Capitalized	27	21	59	37
Other Non-Operating (Income) Expense, Net	(3)	(9)	(3)	—
Total	(252)	(131)	(124)	180
Income from Continuing Operations Before Income Taxes	390	356	724	325
Income Tax Provision	115	87	200	90
Income from Continuing Operations	275	269	524	235
Discontinued Operations, Net of Tax	17	25	32	73
Net Income	$292	$294	$556	$308
Earnings Per Share, Basic				
Income from Continuing Operations	$1.55	$1.51	$2.95	$1.33
Discontinued Operations, Net of Tax	0.09	0.15	0.18	0.42
Net Income	$1.64	$1.66	$3.13	$1.75
Earnings Per Share, Diluted				
Income from Continuing Operations	$1.49	$1.47	$2.88	$1.31
Discontinued Operations, Net of Tax	0.09	0.14	0.18	0.42
Net Income	$1.58	$1.61	$3.06	$1.73
Weighted Average Number of Shares Outstanding				
Basic	178	176	178	176
Diluted	180	179	180	178

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

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Noble Energy, Inc.
Consolidated Statements of Comprehensive Income
(millions)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net Income	$292	$294	$556	$308
Other Items of Comprehensive Income (Loss)				
Interest Rate Cash Flow Hedges				
Unrealized Change in Fair Value	—	—	—	23
Less Tax Provision	—	—	—	(8)
Net Change in Other	1	1	3	3
Other Comprehensive Income	1	1	3	18
Comprehensive Income	$293	$295	$559	$326

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

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Noble Energy, Inc.
Consolidated Balance Sheets
(millions)
(unaudited)

	June 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$702	$1,455
Accounts Receivable, Net	824	783
Other Current Assets	368	180
Assets Held for Sale	324	—
Total Current Assets	2,218	2,418
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	18,440	17,703
Property, Plant and Equipment, Other	322	294
Total Property, Plant and Equipment, Gross	18,762	17,997
Accumulated Depreciation, Depletion and Amortization	(5,337)	(5,215)
Total Property, Plant and Equipment, Net	13,425	12,782
Goodwill	696	696
Other Noncurrent Assets	642	548
Total Assets	$16,981	$16,444
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,279	$1,343
Other Current Liabilities	1,060	925
Total Current Liabilities	2,339	2,268
Long-Term Debt	4,074	4,100
Deferred Income Taxes, Noncurrent	2,080	2,059
Other Noncurrent Liabilities	683	752
Total Liabilities	9,176	9,179
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	—	—
Common Stock - Par Value $0.01 and $3.33 1/3 per share; 500 Million and 250 Million Shares Authorized; 198 Million and 197 Million Shares Issued, Respectively	2	656
Additional Paid in Capital	3,224	2,497
Accumulated Other Comprehensive Loss	(97)	(100)
Treasury Stock, at Cost; 19 Million Shares	(651)	(638)
Retained Earnings	5,327	4,850
Total Shareholders' Equity	7,805	7,265
Total Liabilities and Shareholders' Equity	$16,981	$16,444

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

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Noble Energy, Inc.
Consolidated Statements of Cash Flows
(millions)
(unaudited)

	Six Months Ended June 30,	
	2012	2011
Cash Flows From Operating Activities		
Net Income	$556	$308
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	651	456
Asset Impairments	73	139
Dry Hole Cost	118	45
Deferred Income Taxes	92	44
Dividends (Income) from Equity Method Investees, Net	(7)	(5)
Unrealized (Gain) Loss on Commodity Derivative Instruments	(204)	160
Gain on Divestitures	(9)	(26)
Other Adjustments for Noncash Items Included in Income	41	45
Changes in Operating Assets and Liabilities		
Increase in Accounts Receivable	(58)	(32)
Increase in Other Current Assets	(49)	(17)
Increase in Accounts Payable	84	188
Decrease in Current Income Taxes Payable	(13)	(62)
Increase in Other Current Liabilities	14	1
Other Operating Assets and Liabilities, Net	(42)	(15)
Net Cash Provided by Operating Activities	1,247	1,229
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,900)	(1,261)
Additions to Equity Method Investments	(35)	—
Proceeds from Divestitures	10	77
Net Cash Used in Investing Activities	(1,925)	(1,184)
Cash Flows From Financing Activities		
Exercise of Stock Options	26	26
Excess Tax Benefits from Stock-Based Awards	13	9
Dividends Paid, Common Stock	(79)	(64)
Purchase of Treasury Stock	(13)	(16)
Proceeds from Credit Facilities	—	120
Repayment of Credit Facilities	—	(470)
Proceeds from Issuance of Senior Long-Term Debt, Net	—	836
Settlement of Interest Rate Derivative Instrument	—	(40)
Repayment of Capital Lease Obligation	(22)	—
Net Cash Provided By (Used In) Financing Activities	(75)	401
Increase (Decrease) in Cash and Cash Equivalents	(753)	446
Cash and Cash Equivalents at Beginning of Period	1,455	1,081
Cash and Cash Equivalents at End of Period	$702	$1,527

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

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Noble Energy, Inc.
Consolidated Statements of Shareholders' Equity
(millions)
(unaudited)

	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2011	$656	$2,497	$(100)	$(638)	$4,850	$7,265
Net Income	—	—	—	—	556	556
Stock-based Compensation	—	34	—	—	—	34
Exercise of Stock Options	—	26	—	—	—	26
Tax Benefits Related to Exercise of Stock Options	—	13	—	—	—	13
Dividends (44 cents per share)	—	—	—	—	(79)	(79)
Changes in Treasury Stock, Net	—	—	—	(13)	—	(13)
Change in Par Value	(654)	654		—	—	—
Net Change in Other	—	—	3	—	—	3
June 30, 2012	$2	$3,224	$(97)	$(651)	$5,327	$7,805
December 31, 2010	$651	$2,385	$(104)	$(624)	$4,540	$6,848
Net Income	—	—	—	—	308	308
Stock-based Compensation	—	29	—	—	—	29
Exercise of Stock Options	2	24	—	—	—	26
Tax Benefits Related to Exercise of Stock Options	—	9	—	—	—	9
Dividends (36 cents per share)	—	—	—	—	(64)	(64)
Changes in Treasury Stock, Net	—	—	—	(16)	—	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	—	—	15	—	—	15
Net Change in Other	1	(1)	3	—	—	3
June 30, 2011	$654	$2,446	$(86)	$(640)	$4,784	$7,158

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our core operating areas are onshore US, primarily in the DJ Basin and Marcellus Shale, in the deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US GAAP for complete financial statements. The accompanying consolidated financial statements at June 30, 2012 and December 31, 2011 and for the three and six months ended June 30, 2012 and 2011 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. Certain reclassifications of amounts previously reported have been made to reflect the operations of our North Sea geographical segment as discontinued, as well as to conform to current year presentations. See Note 3. Acquisitions and Divestitures.

These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our Annual Report on Form 10-K for the year ended December 31, 2011.

Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates.

Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices, including the declines in US crude oil and natural gas prices occurring in the second quarter of 2012, results in increased uncertainty inherent in such estimates and assumptions. Further declines in commodity prices could result in a reduction in our fair value estimates and cause us to perform analysis to determine if our oil and gas properties and/or goodwill are impaired.

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Statements of Operations Information Other statements of operations information is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Other Revenues [1]	$—	$11	$—	$33
Production Expense				
Lease Operating Expense	$100	$83	$205	$163
Production and Ad Valorem Taxes	44	39	81	70
Transportation and Gathering Expense	25	15	48	31
Total	$169	$137	$334	$264
Other Operating (Income) Expense, Net				
Deepwater Gulf of Mexico Moratorium Expense [2]	$—	$1	$—	$19
Electricity Generation Expense [1]	—	9	—	26
Gain on Divestitures	(9)	(25)	(9)	(26)
Other, Net	7	4	19	(1)
Total	$(2)	$(11)	$10	$18
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (Income) Expense [3]	$(11)	$(7)	$(8)	$3
Interest Income	—	(2)	—	(5)
Other (Income) Expense, Net	8	—	5	2
Total	$(3)	$(9)	$(3)	$—

(1) Other revenues consist of electricity sales from the Machala power plant, located in Machala, Ecuador, through May 2011. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation and changes in the allowance for doubtful accounts. In May 2011, we transferred our assets in Ecuador to the Ecuadorian government.

(2) Amount relates to rig stand-by expense incurred prior to receiving a permit to resume drilling activities in the deepwater Gulf of Mexico.

(3) Amounts represent increases (decreases) in the fair value of shares of our common stock held in a rabbi trust.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	June 30, 2012	December 31, 2011
Accounts Receivable, Net		
Commodity Sales	$319	$356
Joint Interest Billings	394	313
Other	120	123
Allowance for Doubtful Accounts	(9)	(9)
Total	$824	$783
Other Current Assets		
Inventories, Current	$67	$78
Commodity Derivative Assets	85	10
Deferred Income Taxes, Net (1)	100	41
Probable Insurance Claims (2)	31	15
Prepaid Expenses and Other Current Assets	85	36
Total	$368	$180
Other Noncurrent Assets		
Equity Method Investments	$373	$329
Mutual Fund Investments	104	99
Commodity Derivative Assets	85	37
Other Assets, Noncurrent	80	83
Total	$642	$548
Other Current Liabilities		
Production and Ad Valorem Taxes	$119	$121
Commodity Derivative Liabilities	2	76
Income Taxes Payable	107	127
Asset Retirement Obligations	45	33
Interest Payable	55	56
CONSOL Installment Payment (3)	327	324
Current Portion of FPSO Lease Obligation	53	45
Liabilities Associated with Assets Held for Sale	234	—
Other	118	143
Total	$1,060	$925
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$224	$222
Asset Retirement Obligations	298	344
Accrued Benefit Costs	89	88
Commodity Derivative Liabilities	—	7
Other	72	91
Total	$683	$752

(1) Increase from December 31, 2011 is due to reclassification of deferred income tax assets from long-term to short-term as certain foreign entities are estimated to begin utilizing net operating loss carryforwards in 2012 and 2013.

(2) Amounts represent the costs incurred to date of the Leviathan-2 appraisal well and expected well abandonment costs in excess of the insurance deductible less insurance proceeds received to date. See Note 9. Asset Retirement

Obligations.

(3) See Note 3. Acquisitions and Dispositions and Note 5. Debt.

Changes in Shareholders' Equity On April 24, 2012, our shareholders voted to approve an amendment to the Company's Certificate of Incorporation to (i) increase the number of authorized shares of our common stock from 250 million to 500 million shares and (ii) reduce the par value of the Company's common stock from $3.33 1/3 per share to $0.01 per share. See

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

the Consolidated Statements of Shareholders' Equity.

Recently Issued Accounting Standards Updates In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual and interim periods beginning after December 15, 2011. As of March 31, 2012, we have adopted the provisions of ASU 2011-04, which did not impact our consolidated financial statements. The only impact was to our fair value disclosures. See Note 7. Fair Value Measurements and Disclosures.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on our financial position and results of operations.

Note 3. Acquisitions and Divestitures

Pending Sale of North Sea Properties On May 30, 2012, we announced that we have entered into an agreement for the sale of our 30% non-operated working interests in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea. We expect to receive $127 million, subject to customary adjustments for net cash flows between the effective date of January 1, 2012 and the closing date, which is expected to occur by the end of the third quarter of 2012. We expect to reverse a deferred tax liability and recognize a corresponding income tax benefit of approximately $103 million when the sale closes in the third quarter of 2012.

We continue to market our remaining North Sea properties. As of June 30, 2012, all the properties in our North Sea geographical segment met the criteria for classification as held for sale in our consolidated balance sheets. Our consolidated statements of operations have been reclassified for all periods presented to reflect the operations of our North Sea geographical segment as discontinued. Upon reclassification as held for sale, depreciation, depletion, and amortization (DD&A) ceased. Our long-term debt is recorded at the consolidated level; therefore no interest expense has been allocated to discontinued operations.

North Sea assets and liabilities classified as held for sale were as follows:

	June 30, 2012
(millions)	
Current Assets	
Accounts Receivable, Net	$19
Other Current Assets	11
Total Current Assets	30
Property, Plant and Equipment, Net	294
Total Assets Held for Sale	$324
Accounts Payable - Trade	$9
Asset Retirement Obligation	89
Deferred Tax Liability	136
Total Liabilities Related to Assets Held for Sale	$234

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Summarized results of discontinued operations are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Oil and Gas Sales	$65	$112	$140	$225
Income Before Income Taxes	39	69	79	137
Income Tax Expense	22	44	47	64
Discontinued Operations, Net of Tax	$17	$25	$32	$73

Pending Sale of Onshore US Properties In July 2012, the Board of Directors approved the sale of certain crude oil and natural gas properties in western Oklahoma, western Texas, and the Texas Panhandle for $937 million. We subsequently signed sale agreements related to those properties with two purchasers. The combined net book values of these properties as of June 30, 2012, was approximately $765 million, excluding an allocation of US reporting unit goodwill. The transactions have effective dates of April 1, 2012 and are expected to close in the third quarter of 2012, subject to customary closing conditions and adjustments.

Marcellus Shale Joint Venture On September 30, 2011, we closed an agreement with a subsidiary of CONSOL Energy Inc. (CONSOL) for the development of Marcellus Shale properties in southwest Pennsylvania and northwest West Virginia. Under the agreement, we acquired a 50% interest in approximately 628,000 net undeveloped acres, certain producing properties, and existing infrastructure, such as pipeline and gathering facilities, for approximately $1.3 billion, including post-closing adjustments. We and CONSOL also formed CONE Gathering LLC (CONE) to own and operate the existing and future infrastructure. We have paid a total of $610 million as of June 30, 2012, and, other than post-closing adjustments, the remainder will be paid in two annual installments. See Note 5. Debt.

As part of the joint venture transaction, we agreed to fund one-third of CONSOL’s 50% working interest share of future drilling and completion costs, capped at $400 million each year, up to approximately $2.1 billion (CONSOL Carried Cost Obligation), which is expected to be paid out over approximately eight years. The CONSOL Carried Cost Obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices.

As a result of the transaction, we recorded the following:

	June 30, 2012
(millions)	
Unproved Oil and Gas Properties	$853
Proved Oil and Gas Properties	386
Investment in CONE Gathering LLC	69
Total Assets Acquired [1]	$1,308

[1] Total reflects impact of $17 million imputed interest on CONSOL installment payments.

We used an income approach to estimate the fair value of the proved oil and gas properties as of the acquisition date. We utilized a discounted cash flow model which took into account the following inputs to arrive at estimates of future net cash flows:

- estimated quantities of crude oil and natural gas reserves prepared by our qualified petroleum engineers;
- management’s estimates of future commodity prices based on NYMEX Henry Hub natural gas futures prices and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar properties which we operate.

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We discounted the resulting future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. The fair value of the proved producing properties is considered a Level 3 fair value measurement.

Certain data necessary to complete the final purchase price allocation for proved oil and gas properties is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed. We expect to complete the final purchase price allocation during the twelve-month period following the acquisition date, during which time the preliminary allocation may be revised.

Note 4. Asset Impairments
Pre-tax (non-cash) asset impairment charges were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
South Raton (Deepwater Gulf of Mexico)	$34	$—	$34	$—
Piceance (Onshore US)	39	—	39	—
East Texas (Onshore US)	—	116	—	116
Other (Onshore US)	—	15	—	21
Total	$73	$131	$73	$137

2012 Due to recent declines in near-term crude oil prices, we determined that the carrying amount of our South Raton development in the deepwater Gulf of Mexico was not recoverable from future cash flows and, therefore, was impaired. In addition, due to recent declines in realized natural gas prices, we determined that the carrying amount of our Piceance development, onshore US, was not recoverable from future cash flows and, therefore, was impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models.
2011 Due to field performance combined with a low natural gas price environment, we determined that the carrying amounts of certain of our onshore US developments, primarily in East Texas, were not recoverable from future cash flows and, therefore, were impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models.
See Note 7. Fair Value Measurements and Disclosures.

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Note 5. Debt

Our debt consists of the following:

(millions, except percentages)	June 30, 2012 Debt	Interest Rate		December 31, 2011 Debt	Interest Rate	
Credit Facility, due October 14, 2016 (1)	$—	—		$—	—	
CONSOL Installment Payments, due September 30, 2012 and 2013	656	1.76	% (2)	656	1.76	% (2)
FPSO Lease Obligation	333	—		355	—	
5¼% Senior Notes, due April 15, 2014	200	5.25	%	200	5.25	%
8¼% Senior Notes, due March 1, 2019	1,000	8.25	%	1,000	8.25	%
4.15% Senior Notes, due December 15, 2021	1,000	4.15	%	1,000	4.15	%
7¼% Senior Notes, due October 15, 2023	100	7.25	%	100	7.25	%
8% Senior Notes, due April 1, 2027	250	8.00	%	250	8.00	%
6% Senior Notes, due March 1, 2041	850	6.00	%	850	6.00	%
7¼% Senior Debentures, due August 1, 2097	84	7.25	%	84	7.25	%
Total	4,473			4,495		
Unamortized Discount	(19	)		(26	)	
Total Debt, Net of Discount	4,454			4,469		
Less Amounts Due Within One Year						
CONSOL Installment Payment, due September 30, 2012, net of discount	(327	)		(324	)	
FPSO Lease Obligation	(53	)		(45	)	
Long-Term Debt Due After One Year	$4,074			$4,100		

(1) Our Credit Agreement provides for a $3.0 billion unsecured five-year revolving credit facility. The Credit Facility is available for general corporate purposes.
(2) Imputed rate based on the prevailing market rates for similar debt instruments at the date of assessment.

See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our debt.

Note 6. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price.

We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also may enter into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk   Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk.

Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument   In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated March 2011 debt issuance. During first quarter 2011, the net liability position on the swap was reduced in our mark to market calculation, and we recognized a corresponding gain of $23 million, net of tax, in AOCL. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million at the time of settlement. Approximately $26 million, net of tax, was recorded in accumulated other comprehensive loss (AOCL) and is being reclassified to interest expense over the term of the notes. The ineffective portion of the interest rate swap was de minimis.

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Unsettled Derivative Instruments As of June 30, 2012, we had entered into the following crude oil derivative instruments:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of June 30, 2012							
2012	Swaps	NYMEX WTI [1]	5,000	$91.84	$—	$—	$—
2012	Swaps	Dated Brent	8,000	89.06	—	—	—
2012	Three-Way Collars	NYMEX WTI	23,000	—	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	—	70.00	95.83	105.00
2013	Swaps	NYMEX WTI	3,000	87.00	—	—	—
2013	Swaps	Dated Brent	3,000	98.03	—	—	—
2013	Two-Way Collars	NYMEX WTI	5,000	—	—	95.00	115.00
2013	Three-Way Collars	NYMEX WTI	7,000	—	63.57	83.57	109.04
2013	Three-Way Collars	Dated Brent	26,000	—	82.88	100.86	127.32
2014	Swaps	NYMEX WTI	5,000	86.50	—	—	—
2014	Swaps	Dated Brent	8,000	105.94	—	—	—
2014	Three-Way Collars	Dated Brent	10,000	—	85.00	98.50	129.24

[1] West Texas Intermediate

As of June 30, 2012, we had entered into the following natural gas derivative instruments:

Settlement Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of June 30, 2012							
2012	Swaps	NYMEX HH [1]	30,000	$5.10	$—	$—	$—
2012	Two-Way Collars	NYMEX HH	40,000	—	—	3.25	5.14
2012	Three-Way Collars	NYMEX HH	110,000	—	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	—	—	—
2013	Two-Way Collars	NYMEX HH	40,000	—	—	3.25	5.14
2013	Three-Way Collars	NYMEX HH	100,000	—	3.88	4.75	5.63

[1] Henry Hub

As of June 30, 2012, we had entered into the following natural gas basis swaps:

Settlement Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2012	IFERC CIG [1]	NYMEX HH	150,000	$(0.52)

[1] Colorado Interstate Gas – Northern System

Fair Value Amounts and Gains and Losses on Derivative Instruments   The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	June 30, 2012		December 31, 2011		June 30, 2012		December 31, 2011	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments	Current Assets	$85	Current Assets	$10	Current Liabilities	$2	Current Liabilities	$76
	Noncurrent Assets	85	Noncurrent Assets	37	Noncurrent Liabilities	—	Noncurrent Liabilities	7
Total		$170		$47		$2		$83

The effect of derivative instruments on our consolidated statements of operations was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2012	2011	2012	2011
Realized Mark-to-Market (Gain) Loss	$1	$(1)	$24	$(17)
Unrealized Mark-to-Market (Gain) Loss	(277)	(142)	(204)	160
Total (Gain) Loss on Commodity Derivative Instruments	$(276)	$(143)	$(180)	$143

AOCL at June 30, 2012 included deferred losses of $26 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due April 2014 and March 2041. Approximately $2 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 7. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable   The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments   Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments   Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars, and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into

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account market volatility, market prices and contract terms. See Note 6. Derivative Instruments and Hedging Activities.

Deferred Compensation Liability The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See Mutual Fund Investments above.

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [2]	Significant Unobservable Inputs (Level 3) [3]	Adjustment [4]	Fair Value Measurement
(millions)					
June 30, 2012					
Financial Assets					
Mutual Fund Investments	$104	$—	$—	$—	$104
Commodity Derivative Instruments	—	193	—	(23)	170
Financial Liabilities					
Commodity Derivative Instruments	—	(25)	—	23	(2)
Portion of Deferred Compensation Liability Measured at Fair Value	(158)	—	—	—	(158)
December 31, 2011					
Financial Assets					
Mutual Fund Investments	$99	$—	$—	$—	$99
Commodity Derivative Instruments	—	99	—	(52)	47
Financial Liabilities					
Commodity Derivative Instruments	—	(135)	—	52	(83)
Portion of Deferred Compensation Liability Measured at Fair Value	(162)	—	—	—	(162)

(1) Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

(2) Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.

(3) Level 3 measurements are fair value measurements which use unobservable inputs.

(4) Amount represents the impact of master netting agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Asset Impairments We determined that the carrying amounts of certain assets were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values. Information about the impaired assets is as follows:

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Description	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value [1]	Total Pre-tax (Non-cash) Impairment Loss
millions					
Three Months Ended June 30, 2012					
Impaired Oil and Gas Properties	$—	$—	$172	$245	$73
Three Months Ended June 30, 2011					
Impaired Oil and Gas Properties	—	—	29	160	131
Six Months Ended June 30, 2012					
Impaired Oil and Gas Properties	—	—	172	245	73
Six Months Ended June 30, 2011					
Impaired Oil and Gas Properties	—	—	32	169	137

[1] Amount represents net book value at the date of assessment.

The fair values of the properties were determined as of the date of the assessment using discounted cash flow models. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future oil and gas production, commodity prices based on NYMEX commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10%. See Note 4. Asset Impairments.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public fixed rate debt to be a Level 1 measurement on the fair value hierarchy. The carrying amounts of the CONSOL installment payments approximate fair value because they have been discounted at the prevailing market rates for similar debt instruments at the date of assessment, September 30, 2011. As such, we consider the fair value of our CONSOL installment payments to be Level 2 measurements on the fair value hierarchy. See Note 5. Debt. Fair value information regarding our debt is as follows:

	June 30, 2012 Carrying Amount	Fair Value	December 31, 2011 Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount [1]	$4,121	$4,712	$4,114	$4,733

[1] Excludes Aseng FPSO lease obligation. No floating rate debt was outstanding at June 30, 2012 or December 31, 2011. See Note 5. Debt.

Note 8. Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense as dry hole cost.

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Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

(millions)	Six Months Ended June 30, 2012
Capitalized Exploratory Well Costs, Beginning of Period	$696
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	160
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(9)
Capitalized Exploratory Well Costs Charged to Expense [1]	(107)
Other [2]	(19)
Capitalized Exploratory Well Costs, End of Period	$721

[1] Amount primarily represents the Deep Blue exploratory well (deepwater Gulf of Mexico) costs capitalized prior to December 31, 2011. Although hydrocarbons were found in both the initial exploration well and subsequent sidetrack, we and our partners have decided not to proceed with additional appraisal activities at this time.
[2] Amount represents the Selkirk exploratory well (North Sea) which, along with our remaining North Sea assets, was reclassified to held for sale at June 30, 2012. See Note 3. Acquisitions and Divestitures.

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced, and the number of projects that have been capitalized for a period greater than one year:

(millions)	June 30, 2012	December 31, 2011
Exploratory Well Costs Capitalized for a Period of One Year or Less	$330	$318
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	391	378
Balance at End of Period	$721	$696
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	8	9

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The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of June 30, 2012:

		Suspended Since		
	Total	2011	2010	2009 & Prior
(millions)				
Country/Project:				
Offshore Equatorial Guinea				
Blocks O and I	$155	$43	$6	$106
Offshore Cameroon				
YoYo	44	4	2	38
Offshore Israel				
Leviathan	62	21	41	—
Leviathan-1 Deep	27	27	—	—
Dalit	22	—	1	21
Deepwater Gulf of Mexico				
Gunflint	68	9	3	56
Other				
2 projects of $10 million or less each	13	7	6	—
Total	$391	$111	$59	$221

Blocks O and I   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries. During 2011, we drilled the successful Diega appraisal well which encountered both crude oil and natural gas. We have drilled two sidetracks, each of which encountered hydrocarbons. We are currently evaluating regional development scenarios that will include Diega, along with the successful Carla appraisal well, which was drilled in the fourth quarter of 2011.

YoYo   YoYo is a 2007 natural gas and condensate discovery. During 2011 we acquired and processed additional 3-D seismic information and are continuing evaluations for future drilling potential.

Leviathan   Leviathan is a 2010 natural gas discovery. We are continuing to evaluate the discovery with the successful drilling of the Leviathan-3 appraisal well and will require an additional one or two appraisal wells to further define Leviathan’s natural gas areal extent. We have project and commercial teams in place and are considering our natural gas commercialization options. Due to the scale of the discovery, economic viability depends on the ability to export via pipeline or LNG. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. Engineering design and planning work are currently underway for a potential first phase of development. In addition, we are working with our existing partners to identify a potential partner who can provide technical and financial support as well as midstream and downstream expertise.

Leviathan-1 Deep In January 2012, we resumed drilling at the Leviathan-1 well in order to evaluate two deeper intervals for the existence of crude oil (Leviathan-1 Deep). In May 2012, due to high well pressure and the mechanical limits of the wellbore design, we suspended drilling operations. Although the well did not reach the planned objective, we are encouraged by the possibility of an active thermogenic (heat producing) petroleum system at greater depths within the basin. We are continuing our evaluation of Leviathan-1 Deep and will integrate the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically to test the deep oil concept. Part of the plan will be to secure a rig with the capabilities necessary to reach the target objective.

Dalit   Dalit is a 2009 natural gas discovery. We are currently working with our partners on a cost-effective development plan.

Gunflint   Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. In July 2012, we reached target depth on our Gunflint appraisal well and are currently evaluating the drilling results. Additional appraisal locations are currently being evaluated. Front-end conceptual studies have been completed, and we are working toward sanctioning of a scalable development project.

Note 9. Asset Retirement Obligations

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Asset retirement obligations (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Six Months Ended June 30,	
	2012	2011
(millions)		
Asset Retirement Obligations, Beginning Balance	$377	$253
Liabilities Incurred	23	1
Liabilities Settled	(2)	(12)
Revision of Estimate	20	6
Accretion Expense	14	10
Other	(89)	—
Asset Retirement Obligations, Ending Balance	$343	$258

Liabilities incurred in 2012 relate primarily to wells drilled offshore Israel and include costs to abandon the Leviathan-2 appraisal well. See Note 2. Basis of Presentation. Revisions relate primarily to changes in estimated costs for future abandonment activities in China. Other includes ARO liabilities associated with North Sea properties held for sale. North Sea ARO liabilities have been included within liabilities associated with assets held for sale. See Note 3. Acquisitions and Divestitures.

Liabilities settled in 2011 related primarily to deepwater Gulf of Mexico and Gulf of Mexico shelf properties.

Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 10. Basic and Diluted Earnings Per Share

Basic earnings per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings per share of common stock include the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust (when dilutive). The following table summarizes the calculation of basic and diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions, except per share amounts)				
Income from Continuing Operations	$275	$269	$524	$235
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust (1)	(7)	(4)	(5)	—
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$268	$265	$519	$235
Weighted Average Number of Shares Outstanding, Basic	178	176	178	176
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	2	3	2	2
Weighted Average Number of Shares Outstanding, Diluted	180	179	180	178

Earnings from Continuing Operations Per Share, Basic	$1.55	$1.51	$2.95	$1.33
Earnings from Continuing Operations Per Share, Diluted	1.49	1.47	2.88	1.31
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	2	3	3

(1) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while our common shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculations for the three months ended June 30, 2012 and 2011 and for the six months ended June 30, 2012 exclude deferred compensation gains,

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net of tax.

Note 11. Income Taxes

The income tax provision relating to continuing operations consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Current	$56	$39	$100	$36
Deferred	59	48	100	54
Total Income Tax Provision	$115	$87	$200	$90
Effective Tax Rate	29 %	24 %	28 %	28 %

Our effective tax rate for the first six months of 2012 was the same as the first six months of 2011. During the second quarter of 2012, we recognized income tax expense of $13 million with respect to a reserve for uncertain tax positions related to prior years.

During the six months of 2011, we increased the valuation allowance against our deferred tax asset for foreign tax credits by $14 million resulting in a corresponding increase in income tax expense.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2008, Equatorial Guinea – 2007, Israel – 2008, UK – 2010, the Netherlands – 2009, and China – 2006.

See Note 3. Acquisitions and Divestitures for income taxes related to discontinued operations.

Note 12. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into four components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Senegal/Guinea-Bissau); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes China, Ecuador (through May 2011), and new ventures. As of June 30, 2012, our North Sea geographical segment was reclassified to held for sale. See Note 3. Acquisitions and Divestitures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended June 30, 2012					
Revenues from Third Parties	$934	$527	$332	$29	$46
Income from Equity Method Investees	32	1	31	—	—
Total Revenues	966	528	363	29	46
DD&A	325	232	62	10	21
Asset Impairments (1)	73	73	—	—	—
Gain on Divestiture	(9)	(9)	—	—	—
Gain on Commodity Derivative Instruments (2)	(276)	(93)	(183)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	390	48	455	5	(118)
Three Months Ended June 30, 2011					
Revenues from Third Parties	$794	$553	$118	$76	$47
Income from Equity Method Investees	48	—	48	—	—
Total Revenues	842	553	166	76	47
DD&A	211	187	7	7	10
Asset Impairments (1)	131	131	—	—	—
Gain on Divestiture (3)	(25)	—	—	—	(25)
Gain on Commodity Derivative Instruments (2)	(143)	(142)	(1)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	356	250	116	57	(67)
Six Months Ended June 30, 2012					
Revenues from Third Parties	$1,970	$1,080	$715	$73	$102
Income from Equity Method Investees	86	3	83	—	—
Total Revenues	2,056	1,083	798	73	102
DD&A	619	430	135	15	39
Asset Impairments (1)	73	73	—	—	—
Gain on Divestiture	(9)	(9)	—	—	—
(Gain) on Commodity Derivative Instruments (2)	(180)	(102)	(78)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	724	241	682	37	(236)
Six Months Ended June 30, 2011					
Revenues from Third Parties	$1,533	$1,059	$248	$128	$98
Income from Equity Method Investees	96	—	96	—	—
Total Revenues	1,629	1,059	344	128	98
DD&A	404	354	17	11	22
Asset Impairments (1)	137	137	—	—	—
Gain on Divestiture (3)	(26)	(1)	—	—	(25)
Loss on Commodity Derivative Instruments (2)	143	50	93	—	—
Income (Loss) from Continuing Operations Before Income Taxes	325	213	190	96	(174)
June 30, 2012					
Goodwill	$696	$696	$—	$—	$—
Total Assets	16,657	11,188	2,761	2,289	419

December 31, 2011					
Goodwill	696	696	—	—	—
Total Assets	16,106	11,201	2,728	1,751	426

(1) See Note 4. Asset Impairments.
(2) See Note 6. Derivative Instruments and Hedging Activities.
(3) Amount relates primarily to the transfer of our Ecuador assets to the Ecuadorian government. See Note 2. Basis of Presentation.

Note 13. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

COGCC During 2011, we received two Notices of Alleged Violation (NOAV) from the Colorado Oil and Gas Conservation Commission (COGCC) regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. We are in ongoing discussions with the COGCC in an effort to favorably resolve this matter but we are unable to predict the ultimate outcome at this time. However, we believe that the final resolution will not have a material adverse effect on our financial position, results of operations or cash flows.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. Our MD&A is presented in the following major sections:

- Executive Overview;
- Operating Outlook;
- Results of Operations; and
- Liquidity and Capital Resources.

The preceding consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with our MD&A.

EXECUTIVE OVERVIEW

We are a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our aim is to achieve growth in value and cash flows through exploration success and the development of a high-quality, diversified portfolio of producing assets that is balanced between US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Our financial results for the second quarter of 2012 included:

- net income of $292 million, as compared with $294 million for second quarter 2011;
- dry hole cost of $118 million, as compared with $45 million for second quarter 2011;
- impairment loss of $73 million, as compared with $131 million for second quarter 2011;
- gain on commodity derivative instruments of $276 million (including unrealized mark-to-market gain of $277 million) as compared with a gain on commodity derivative instruments of $143 million (including unrealized mark-to-market gain of $142 million) for second quarter 2011;
- diluted earnings per share of $1.58, as compared with $1.61 for second quarter 2011;
- cash flow provided by operating activities of $506 million, as compared with $745 million for second quarter 2011;
- ending cash balance of $702 million, as compared with $1.5 billion at December 31, 2011;
- capital spending, on a cash basis, of $882 million, as compared with $683 million for second quarter of 2011; and
- ratio of debt-to-book capital of 36% as compared with 38% at December 31, 2011.

Key highlights for the second quarter 2012 included:

- horizontal net production within the DJ Basin increased 33% percent from last quarter;
- improved Wattenberg horizontal well estimated ultimate recoveries (EURs) in the extension area;
- Marcellus Shale well with extended-reach lateral of 8,500 feet produced at an initial rate of 17.9 MMcf/d;
- Aseng field, offshore Equatorial Guinea, produced at a record average gross rate of 63 MBbl/d of oil (21 MBbl/d net);
- initiated gross production from the Noa field, offshore Israel, at a rate of 100 MMcf/d (41 MMcf/d net);
- signed a sales agreement to divest Dumbarton and Lochranza assets in the North Sea;
- achieved start-up at the Galapagos project in the deepwater Gulf of Mexico at rates 30% above original estimates; and
- identified as high bidder on six deepwater Gulf of Mexico blocks at the Outer-Continental Shelf Sale 222.

Exploration Program Update

We continue to evaluate and build upon our significant exploration inventory in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other international new venture locations. We continually evaluate and high-grade our exploration inventory to provide additional growth opportunities and potential new core areas. In addition, each of our existing core areas has significant remaining exploration upside. We continue to leverage existing activities to improve our exploratory programs in these core areas.

We were in the process of drilling and/or evaluating significant exploratory wells at June 30, 2012 (See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs), and we expect to continue an active exploratory drilling program in the future.

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We devote significant capital to our exploration program; approximately 20% of our $3.5 billion capital investment program in 2012 is dedicated to exploration and associated appraisal activities. However, we do not always encounter hydrocarbons through our drilling activities. In addition, we may find hydrocarbons but subsequently reach a decision, through additional analysis or appraisal drilling, that a project is not economically or operationally viable.

We are currently conducting, or planning to conduct, exploratory drilling activities in previously unexplored areas as well as appraisal activities at several of our discoveries. In the event we conclude that one of our exploratory wells did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. As a result, in a future period, dry hole cost could be significant.

For example, during 2012, we recorded total dry hole cost of $118 million primarily related to the Deep Blue exploratory well (deepwater Gulf of Mexico). The Deep Blue well was originally spud in late 2009 and sidetrack operations were underway when the deepwater Gulf of Mexico moratorium was announced. After the moratorium was lifted we were able to resume operations and finish the sidetrack. Although hydrocarbons were found in both the initial exploration well and subsequent sidetrack, we and our partners have decided not to proceed with additional appraisal activities at this time.

In addition to dry hole cost, unfavorable exploration activity on a property being evaluated or changes in exploration plans can lead to impairment of capitalized undeveloped leasehold costs, resulting in additional expense.

Updates of our significant exploration activities are as follows:

DJ Basin (Onshore US) Our DJ Basin position now includes over 880,000 net acres and provides us with opportunities to significantly expand beyond our core Wattenberg area activities. We continue to acquire 3-D seismic information and appraise our Northern Colorado and Wyoming acreage.

Northeast Nevada (Onshore US) We constantly strive to identify new onshore exploration opportunities with reasonable entry cost, significant running room and the potential to become a new core area. We recently added a 330,000 net acre position in Northeast Nevada, prospective for oil exploration, which we identified through basin scale reconnaissance and innovative geoscience concepts. We are planning to acquire 3-D seismic over portions of the acreage during 2012, to be followed by a vertical well exploratory drilling program in 2013.

Deepwater Gulf of Mexico We hold significant exploration potential in the deepwater Gulf of Mexico. We plan to continue our exploration activities in the second half of 2012 and are evaluating potential new drilling sites, including our Talon and Big Bend prospects. We also participated in the Central Gulf of Mexico Lease Sale 216/222 and were the apparent high bidder on six deepwater blocks. Deepwater royalty suspension provisions are not applicable to these leases.

Offshore West Africa We are continuing our exploration and appraisal efforts offshore West Africa, where we still have numerous opportunities offshore Equatorial Guinea and Cameroon. Our next planned exploratory well will be the Trema well, on the Tilapia block offshore Cameroon, which we expect to spud in the second half of 2012. We will also begin an appraisal program for our Diega and Carla discoveries and plan to spud an appraisal well before the end of 2012.

In July 2012, the Government of Sierra Leone provisionally awarded us participation in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million acres. The terms are subject to negotiations with the Petroleum Directorate of Sierra Leone.

The first appraisal period for the non-operated AGC Profond block, offshore Senegal/Guinea-Bissau, is due to expire in September 2012. The operator and joint venture partners are currently evaluating whether to move into the second appraisal period. If we elect not to participate in the second appraisal period, undeveloped leasehold cost of $40 million will be charged to expense.

Eastern Mediterranean We continue an active exploration program targeting both natural gas and crude oil resources. In January 2012, we resumed drilling at the Leviathan-1 well in order to evaluate two deeper intervals for the existence of crude oil (Leviathan-1 Deep). In May 2012, due to high well pressure and the mechanical limits of the wellbore design, we suspended drilling operations. Although the well did not reach the planned objective, we are encouraged by the possibility of an active thermogenic (heat producing) petroleum system at greater depths within the basin. We will integrate the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically to test the deep oil concept. Part of the plan will be to secure a rig with the capabilities necessary to reach the target objective.

We are also processing recently acquired seismic information and evaluating other offshore Israel locations for potential exploratory drilling.

In 2011 we announced a significant natural gas discovery at the A-1 well on Block 12, offshore Cyprus. We are in the process of preparing an appraisal plan and reviewing locations for appraisal drilling activities. See Major Development Projects Update - Block 12, below.

Offshore Nicaragua We continue to evaluate our undeveloped acreage for potential drilling sites.

Offshore France We and our partner applied to the French government for an extension of our offshore exploratory license. The period for regulatory review expired without official notification from the French government; therefore, the license was relinquished effective July 15, 2012. The relinquishment had no material impact on our financial position or results of operations.

Major Development Projects Update

During the second quarter of 2012, we continued to advance our major development projects, many of which have resulted from our exploration success. We expect these projects to deliver significant growth in production over the next several years. Updates on our significant development projects are as follows:

Horizontal Niobrara (Onshore US) We have increased our horizontal drilling activity targeting the Niobrara formation in the Wattenberg area, resulting in a significant positive impact on our current production volumes. We expect to drill close to 190 horizontal wells during 2012, more than double the number of horizontal wells that we drilled last year in the area, and we continue to move into areas of higher liquids content. We completed 43 horizontal wells during the second quarter of 2012.

We continue to refine our Wattenberg development strategy to increase our access to additional resources. We continue to evaluate both vertical and areal incremental recoveries, impacts of changes in well spacing and pad design using EcoNode concepts (consolidated well processing facilities), and extended-reach (9,000 feet) lateral wells. We are also testing the Niobrara "C Chalk" and the Codell formation on a horizontal basis.

Additionally, we continue to expand these development activities into Northern Colorado, where our recent horizontal Niobrara results indicate recoveries comparable to those in the Wattenberg area. We have added almost 26,000 net acres to our Northern Colorado position this year, increasing our acreage position to approximately 230,000 net acres. We expect to drill 35-40 horizontal wells, of the planned 190 horizontal wells discussed above, in Northern Colorado, moving to full phase development by the end of the year.

Marcellus Shale (Onshore US) Our joint venture partnership with CONSOL, formed in September 2011, has provided us with a 50% interest in approximately 628,000 net acres in southwest Pennsylvania and northwest West Virgina. Due to the current low natural gas price environment, we and CONSOL have decreased the amount of drilling in the dry gas areas and increased the drilling in the wet gas areas. We assumed operatorship in the wet gas areas early this year.

By applying our DJ Basin experience, we continue to test with longer lateral wells, improved hydraulic fracturing design and optimal well placements. We plan to drill approximately 30 wells in the wet gas area this year, of which six wells were drilled during the second quarter of 2012. We expect to increase activity in the wet gas area with three drilling rigs operating by the end of the year. As we move into new areas, water supply and gas gathering infrastructure are expanding.

Although we have reduced drilling in the dry gas area due to the low natural gas price environment, the dry gas portion of the program continues to deliver economically attractive returns due to strong production performance, high net revenue interests, competitive costs, and access to market. The CONSOL carried cost obligation is currently suspended due to low natural gas prices. See Liquidity and Capital Resources - Contractual Obligations below.

Galapagos (Deepwater Gulf of Mexico) The Galapagos crude oil development project commenced production during the second quarter of 2012 and is currently producing at a sustained rate of approximately 14,500 Boe/d, net. Galapagos consists of three producing wells (Santa Cruz, Isabela and Santiago) connected to the non-operated Na Kika production platform via subsea tieback. We expect this project to have strong cash flows and return on our investment. With the addition of Galapagos, our current deepwater Gulf of Mexico daily production has increased to approximately 30,000 Boe/d, net, with over 80% oil.

South Raton (Deepwater Gulf of Mexico) During the second quarter of 2012, the South Raton crude oil development project commenced production at approximately 3 Mbbl/d, net. South Raton is tied back to a non-operated host facility. Due to the recent decline in near-term crude oil prices, we recognized a $34 million impairment loss for South Raton during the second

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quarter of 2012.

Gunflint (Deepwater Gulf of Mexico) In July 2012, we reached target depth on our Gunflint appraisal well and are currently evaluating the drilling results, a follow up to our significant 2008 Gunflint crude oil discovery. Additional appraisal locations are currently being evaluated. Front-end conceptual studies have been completed, and we are working toward sanctioning of a scalable development project.

Alen (Block O, Offshore Equatorial Guinea) The Alen facilities are designed to provide a hub for future gas monetization opportunities, able to process up to 440 MMcf/d gross, of natural gas, which will be reinjected, and 40 MBbl/d, gross, of condensate which will be piped to the Aseng FPSO and sold. The production and injection wells have been completed; platform and subsea fabrication continue on schedule. First production is expected to commence in the fourth quarter of 2013.

Diega and Carla (Blocks I and O, Offshore Equatorial Guinea) The successful Diega appraisal well, drilled in 2011, encountered both crude oil and natural gas. Carla, also drilled in 2011, was a successful oil appraisal well. We are currently evaluating regional development scenarios and formulating a development plan.

Tamar (Offshore Israel) The Tamar natural gas project includes five subsea wells from which natural gas will flow to a new offshore platform. The natural gas will then be delivered via subsea pipeline to the Ashdod onshore terminal. The development will allow for significant expansion as the Israeli natural gas market grows. The development wells have been drilled, and platform fabrication continues as planned. Tamar remains on schedule for commissioning beginning in late 2012 with first sales in the second quarter of 2013. Natural gas sales contracts have been signed with numerous customers. See Recent Developments Offshore Israel below.

We expect the Israeli natural gas market to continue to grow, driven by both power generation and industrial demand, and are considering additional options for the further potential development of Tamar to provide additional natural gas for both in-country and export use; however, we have not yet sanctioned an additional development project at Tamar.

Leviathan (Offshore Israel) In late 2010, we announced a significant natural gas discovery at the Leviathan-1 well in the Levant Basin offshore Israel. We will require one or two appraisal wells to further define Leviathan’s natural gas areal extent.

We have project and commercial teams in place and are considering our natural gas commercialization options. Due to the scale of the discovery, economic viability depends on the ability to export via pipeline or LNG. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. Engineering design and planning work are currently underway for a potential first phase of development. In addition, we are working with our existing partners to identify a potential partner who can provide technical and financial support as well as midstream and downstream expertise; therefore, we have not yet sanctioned a development project. See Operating Outlook - Israeli Interministerial Committee, below.

Block 12 (Offshore Cyprus) During the fourth quarter of 2011, we drilled a successful natural gas exploration well (A-1) in Block 12. We are in the process of evaluating our commercialization options, including LNG, for the Block 12 natural gas discovery; however, we have not yet sanctioned a development project.

Asset Impairment Charges

During the second quarter of 2012, we recorded total impairment charges of $73 million. These charges included: an impairment charge of $39 million related to the Piceance development, onshore US, which was due primarily to recent declines in realized natural gas prices, and an impairment charge of $34 million related to the South Raton development, deepwater Gulf of Mexico, which was due to declines in near-term crude oil prices. See Item 1. Financial Statements - Note 4. Asset Impairments and Operating Outlook - Potential for Future Asset Impairments below.

Divestitures

We occasionally divest non-core, non-strategic properties from our portfolio to generate organizational and operational efficiencies as well as cash for use in our capital investment program. On May 30, 2012, we announced that we have entered into a definitive agreement for the sale of our 30% non-operated working interests in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea, for $127 million, subject to customary adjustments for net cash flows between the effective date of January 1, 2012 and the closing date, which is expected to occur by the end of third quarter 2012.

We are continuing efforts to divest our remaining North Sea properties. Management has committed to a plan to sell the remaining assets, individually or as packaged groups, and no further approval by the Board of Directors is required. All criteria for classification of the North Sea properties as held for sale had been met as of June 30, 2012. Therefore, all North Sea properties were reclassified as assets held for sale as of June 30, 2012, and the results of operations for the North Sea geographical segment have been reclassified for all periods presented as discontinued operations. See Item 1. Financial Statements - Note 3. Acquisitions and Divestitures - Pending Sale of North Sea Properties.

We are also in the process of marketing certain non-core onshore US properties and currently soliciting bids. As of June 30, 2012, the Board of Directors and management had not committed to any specific plans to sell the assets, individually or as packaged groups. A sale of any of the asset packages currently being marketed requires approval by our Board of Directors. Therefore, none of these assets was reclassified as held-for-sale at June 30, 2012. See Operating Outlook - Potential for Future Asset Impairments below.

In July 2012, the Board of Directors approved the sale of certain crude oil and natural gas properties in western Oklahoma, western Texas, and the Texas Panhandle for $937 million. We subsequently signed sale agreements related to those properties with two purchasers. The combined net book values of these properties as of June 30, 2012, was approximately $765 million, excluding an allocation of US reporting unit goodwill. The transactions have effective dates of April 1, 2012 and are expected to close in the third quarter of 2012, subject to customary closing conditions and adjustments. The properties include our interests in about 1,150 producing wells on approximately 95,000 net acres. As of the effective date, net daily production was approximately 11,500 Boe/d.

Recent Developments Offshore Israel

Mari-B During 2011, due to multiple interruptions in imported gas supplies from Egypt, Mari-B natural gas volumes were delivered at very high rates to support Israel’s growing natural gas and power demands. As a result, we experienced accelerated depletion of the Mari-B field. In January 2012, we announced a cut back in production at Mari-B to prudently manage the reservoir. We are currently working closely with our Israeli customers to manage demand from the Mari-B field and continue production from it.

In order to help meet Israeli natural gas demands until the Tamar field begins producing, we completed the Noa and Pinnacles wells and tied them back to the Mari-B platform. We began selling natural gas from Noa in June 2012 and from Pinnacles in July 2012.

Although Noa and Pinnacles wells are now producing, they will not completely offset the decline in Mari-B production. Therefore, we expect total Israel sales volumes for fiscal year 2012 will be lower than they were in fiscal year 2011. In addition, due to the cost of completing and tying back the Noa and Pinnacles wells, we expect that Israel DD&A expense for fiscal year 2012 will be higher than for fiscal year 2011. Therefore, we expect that our Eastern Mediterranean segment will not be as profitable in 2012 as it was in 2011.

Tamar We and our Tamar partners have entered into Gas Sale and Purchase Agreements (GSPAs) with the Israel Electric Corporation Limited (IEC) and six other Israeli purchasers, including independent power producers, cogeneration facilities and industrial companies, for the sale of natural gas from the Tamar field. During the second quarter of 2012, the Israel Public Utilities Authority - Electricity (PUA) and Israel Anti-Trust Authority reviewed the GSPAs. As a result, we are being required to modify certain terms in the GSPAs including the dates by which the IEC must exercise its increase option and the increase option price indexation. We also must provide each of our remaining purchasers the right, within 90 days of the PUA's decision, to request to shorten the term of the GSPA to seven years or provide them with a partial termination option within a window of time. In addition, we are being required to execute GSPAs on similar terms with additional purchasers, subject to capacity restraints.

After giving effect to the existing GSPA modifications mentioned above, we have agreed to the following:

- the sale of approximately 2.7 Tcf of natural gas to IEC over an approximate 15-year period. IEC has the option to increase this amount to 3.5 Tcf, under certain conditions;
- the sale of approximately 1.3 Tcf of natural gas to six remaining customers over a 16 to 17 year period. Some of the contracts provide for increase or reduction in total quantities; and
- sales prices based on an initial base price subject to price indexation over the life of the contract and with a floor.

The IEC GSPA was amended to comply with the requirements raised by the Israeli regulators and became effective July 25, 2012. All remaining conditions precedent including Israel Anti-Trust Authority, PUA, and government approvals have been satisfied and thereby the IEC GSPA is in full force and effect.

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Leviathan-2 In May 2011, we ended drilling operations at the Leviathan-2 appraisal well when we identified water flowing to the sea floor from the wellbore. We are continuing to monitor the wellbore and there are no indications of any hydrocarbons in the produced water. We have been working with the Israeli government to determine appropriate abandonment activities.

The incident is a covered event under our well control insurance. At this time, we expect to recover most of the costs from insurance, subject to a deductible. Our partners have insurance coverage, but may not have sufficient coverage to cover all possible outcomes relating to abandonment of the well and may have to rely on other financial resources. We do not expect any delays in our insurance claim recovery process to have a significant impact on our cash flows or liquidity. See Item 1. Financial Statements – Note 2. Basis of Presentation and Note 9. Asset Retirement Obligations.

See also Operating Outlook - Israeli Interministerial Committee, below.

Recent Developments in the Marcellus Shale

NETL Study The US Department of Energy's National Energy Technology Laboratory (NETL) is conducting a comprehensive assessment of the environmental effects of shale gas production at two industry-provided Marcellus Shale test sites in southwestern Pennsylvania. Goals include:

- documentation of environmental changes that are coincident with shale gas production;
- development of technology or management practices that mitigate undesigned environmental changes; and
- development of monitoring technologies to (1) assess the impact of shale gas production on air quality and (2)determine if zonal isolation between producing formations and drinking water aquifers is maintained after hydraulic fracturing.

We will monitor the results of the NETL study in order to assess any potential impact on our onshore US development programs.

Butler v. Powers On September 7, 2011, an intermediate appellate court (Superior Court) in Pennsylvania issued an opinion in Butler v. Powers regarding the interpretation of a deed. As a result, traditional views of how ownership of shale gas is determined in that state have been called into question. The issue raised by the case is whether shale gas is different from other natural gas and should be considered part of mineral rights, rather than oil and gas rights, because shale gas is contained inside non-porous shale rock. An appeal of the decision was subsequently filed with the Pennsylvania Supreme Court, which decided to hear the appeal. Written arguments in the case have been presented.

At this time, no case law or interpretation of existing law has changed, nor has there been an indication that either the Superior Court or the Pennsylvania Supreme Court will seek to change existing law. Based upon our initial review, we believe that any adverse decision in the pending case would have minimal adverse impact upon the assets acquired from CONSOL and our Marcellus Shale joint venture operations.

Sales Volumes

On a BOE basis, total sales volumes, excluding sales volumes from discontinued operations, were 10% higher for the second quarter of 2012 as compared with the second quarter of 2011, and our mix of sales volumes was 47% global liquids, 21% international natural gas, and 32% US natural gas. US sales volumes increased due to continued acceleration of our horizontal drilling programs in Wattenberg along with our Marcellus Shale program, which began at the end of the third quarter of 2011. International crude oil sales volumes were higher in Equatorial Guinea due to the commencement of crude oil production at Aseng in the fourth quarter of 2011. Israel natural gas sales volumes were lower as we have reduced the rate of production from the Mari-B field in order to manage the reservoir. See Results of Operations – Revenues below.

Commodity Price Changes and Hedging

Total consolidated average realized crude oil prices for the second quarter of 2012 decreased 5% as compared with the second quarter of 2011. US natural gas prices remain weak; US average realized natural gas prices for the second quarter of 2012 decreased 50% as compared with the second quarter of 2011.

Price decreases were due to a slowdown in the global economic recovery, influenced by uncertainty over the Eurozone debt crisis, and an increase in supply. As long as development activity continues at, or near, the current level and there is no significant increase in demand, downward pressure on commodity prices will continue. See Potential for Future Asset Impairments below.

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We have hedged approximately 41% of our expected global crude oil production and 39% of our expected domestic natural gas production for the remainder of 2012. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities.

OPERATING OUTLOOK

Our expected crude oil, natural gas and NGL production for 2012 may be impacted by several factors including:

- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- timing of major development project completion and initial production;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- pace of increase of development activity in the Marcellus Shale;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and the Mari-B field in Israel, where we reduced production to manage the reservoir (See Recent Developments Offshore Israel, above);
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to scheduled field maintenance and potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth and competing deliveries of natural gas from Egypt and production rates from the Noa field and Pinnacles project, offshore Israel;
- variations in West Africa sales volumes due to potential FPSO downtime and timing of liftings;
- impact of pending sales of certain onshore US and North Sea properties, expected to close by the end of third quarter 2012;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Wattenberg, Rocky Mountain, and/or Marcellus Shale areas of our US operations;
- unseasonably high temperatures in the Wattenberg and/or Rocky Mountain areas of our US operations which may cause restrictions or interruptions in mid-stream processing facilities;
- potential pipeline and processing facility capacity constraints in the Wattenberg, Rocky Mountain, and/or Marcellus Shale areas of our US operations;
- potential drilling and/or hydraulic fracturing permit delays due to future regulatory changes;
- potential purchases of producing properties and/or divestments of non-core operating assets; and
- potential shut-in of US producing properties if storage capacity becomes unavailable.

2012 Capital Investment Program

Our total capital investment program for 2012 is estimated at $3.5 billion. The capital investment program allocates approximately 50% to onshore US and the remainder to offshore deepwater Gulf of Mexico, Eastern Mediterranean, and West Africa. Exploration and appraisal activity within these geographic areas is expected to receive approximately 20% of total capital.

We expect that the remainder of the 2012 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as an issuance of long-term debt. Funding will also be provided by proceeds from divestment of non-core assets. See Liquidity and Capital Resources – Financing Activities below.

We will evaluate the level of capital spending and remain flexible throughout the year based on the following factors, among others:

- commodity prices, including price realizations on specific crude oil and natural gas production including the impact of NGLs;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- permitting activity in the deepwater Gulf of Mexico;
- drilling results;
- CONSOL Carried Cost Obligation (See Contractual Obligations below);
- property acquisitions and divestitures;

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- availability and cost of financing;
- potential legislative or regulatory changes regarding the use of hydraulic fracturing;
- potential changes in the fiscal regimes of the US and other countries in which we operate; and
- impact of new laws and regulations, including implementation of the Dodd-Frank Wall Street Reform and Consumer Protection Act, on our business practices.

Potential for Future Asset Impairments

Global crude oil prices are volatile and decreased during the second quarter of 2012. In addition, US natural gas prices are volatile and the natural gas market remains weak. A further decline in future NYMEX crude oil or natural gas prices could result in additional impairment charges. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward crude oil or natural gas prices alone could result in an impairment.

Additionally, we are currently marketing certain non-core onshore US properties. If the properties are reclassified as assets held for sale, they will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell. In addition, we would allocate a portion of goodwill to any non-core onshore US property held for sale that constitutes a business, which could potentially decrease any gain or increase any loss recorded on the sale.

Israeli Interministerial Committee

In 2011, the Interministerial Committee to Examine Government Policy Regarding the Natural Gas Industry in Israel (the Committee) was charged with the task of proposing a government policy for developing the natural gas economy. Objectives include the following:

- ensuring energy security in the economy;
- providing a framework for substantial resource exports;
- designating a certain percentage of production from each field for the domestic natural gas market;
- maintaining competition in the different sectors of the local economy;
- maximizing economic and political benefits; and
- leveraging environmental advantages with respect to the use of natural gas.

The Committee was also asked to examine, among other items, the desired policy to maintain reserves to supply local demand and export of natural gas. The Committee issued Interim Recommendations on April 5, 2012, which included, among others:

- requiring a minimum 25-year supply of gas to the domestic market;
- allowing for a redetermination of market needs after the year 2018;
- requiring regulatory approval for export;
- determining that an Israeli natural gas export facility be under Israeli control and within the jurisdiction of Israel's economic waters;
- taking steps to increase competition in the natural gas market; and
- requiring infrastructure redundancy, physical connection of all reservoirs to the domestic market, third party access to infrastructure, and the development of statutory procedures to define infrastructures.

We expect the Committee to issue a final report during the third quarter of 2012. We also expect that the Israeli government will enact laws and regulation in response to the Committee's recommendations.

We are participating in the process and monitoring the progress of the Committee and the impact of its recommendations. However, at this time, we cannot predict the ultimate outcome of the Committee’s recommendations or the possible impact any resulting laws or regulations could have on our business. Certain changes in Israel’s market, fiscal, and/or regulatory regimes occurring as a result of the Committee’s recommendations could delay or reduce the profitability of our Tamar and/or Leviathan development projects and render future exploration and development projects uneconomic.

Impact of Dodd-Frank Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, contains significant derivatives regulation, including requirements that certain transactions be cleared on exchanges and that cash collateral (commonly referred to as “margin”) be posted for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, such as us, and it includes a number of defined terms used in determining how this exception applies to particular derivative transactions and the parties to those transactions. As required by the Act, the Commodities Futures and Trading Commission (CFTC) has promulgated numerous rules to define these terms.

We are currently evaluating the provisions of the CFTC's final rules and assessing their impact on our commodity hedging program. At this time, we believe that we will be able to satisfy the requirements for the commercial end-user clearing exception and continue to engage in transactions which hedge commercial risk and are free of mandated clearing requirements.

It is possible that the CFTC, in conjunction with prudential regulators may mandate that financial counterparties entering into swap transactions with end-users must do so with collateral support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral. If this should occur, we intend to manage our credit relationships to minimize collateral requirements.

The CFTC's final rules will also have an impact on our hedging counterparties. For example, our counterparties will be required to post collateral and assume compliance burdens resulting in additional costs. We expect that much of the increased costs will be passed on to us, thereby decreasing the relative effectiveness of our hedges and our profitability.

Risk and Insurance Program

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering, fire, loss of well control, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals, any of which could result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, environmental pollution, injury to persons, or loss of life. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production income), employer’s liability, comprehensive general liability and worker’s compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly. We have limited or no insurance coverage for certain risks such as war or political risk. In addition, coverage is generally limited or not available to us for pollution events that are considered gradual.

In certain international locations (including Israel and Equatorial Guinea) we carry business interruption insurance for loss of production income arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In the Gulf of Mexico, we self-insure for windstorm related exposures. Our Gulf of Mexico assets are primarily subsea operations; therefore, our windstorm exposure is limited. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. We believe it is more cost-effective for us to self-insure these assets.

As is customary with industry practice, crude oil and natural gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons.

Most of our US and international drilling contracts contain such indemnification clauses. In addition, crude oil and natural gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry more than $700 million insurance protection, depending on our ownership interest, for potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of more than $500 million of well control, pollution cleanup and consequential damages coverage and more than $200 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death.

We have contracts with third-party service providers to perform hydraulic fracturing operations for us. The master service agreements signed by hydraulic fracturing providers contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusions for liabilities from hydraulic fracturing operations and we believe our policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. We do not have insurance for gradual pollution nor do we have coverage for penalties or fines that may be assessed by a governmental authority.

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We expect the future availability and cost of insurance to be impacted by the various catastrophic events and large losses that insurers have incurred over the past several years. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We anticipate that ongoing changes in the types of coverage available in the insurance market may result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident of 2010 and other recent international incidents in Brazil and the North Sea, and their impact on the insurance market and our overall risk profile. We anticipate that, at a minimum, less effective liability coverage will be available at a higher cost. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Our business entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a robust prevention program and continue to manage our risks and operations such that we believe the likelihood of a significant event is remote. However, if an event occurs that is not covered by insurance, not fully protected by insured limits or our non-operating partners are not fully insured, it could have a material adverse impact on our financial condition, results of operations and cash flows. See Executive Overview - Recent Developments Offshore Israel.

Recently Issued Accounting Standards Updates

See Item 1. Financial Statements – Note 2. Basis of Presentation.

RESULTS OF OPERATIONS

In the discussion below, prior year amounts have been reclassified to reflect the North Sea segment as discontinued operations. See Discontinued Operations, below.

Revenues

Revenues were as follows:

(millions)	2012	2011	Increase (Decrease) from Prior Year	
Three Months Ended June 30,				
Oil, Gas and NGL Sales	$934	$783	19	%
Income from Equity Method Investees	32	48	(33	)%
Other Revenues	—	11	(100	)%
Total	$966	$842	15	%
Six Months Ended June 30,				
Oil, Gas and NGL Sales	$1,970	$1,500	31	%
Income from Equity Method Investees	86	96	(10	)%

Other Revenues	—	33	(100	)%
Total	$2,056	$1,629	26	%

Changes in revenues are discussed below.

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Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended June 30, 2012							
United States	46	431	16	134	$94.49	$2.10	$33.06
Equatorial Guinea (2)	34	215	—	70	104.55	0.27	—
Israel	—	60	—	10	—	5.44	—
China	5	—	—	5	115.41	—	—
Total Consolidated Operations	85	706	16	219	99.67	1.82	33.06
Equity Investees (3)	1	—	4	5	109.98	—	61.47
Total Continuing Operations	86	706	20	224	$99.81	$1.82	$38.87
Three Months Ended June 30, 2011							
United States	37	378	15	115	$101.99	$4.21	$50.03
Equatorial Guinea (2)	11	233	—	50	114.80	0.27	—
Israel	—	174	—	29	—	4.81	—
China	3	—	—	3	109.96	—	—
Total Consolidated Operations	51	785	15	197	105.23	3.18	50.03
Equity Investees (3)	2	—	5	7	115.23	—	75.83
Total Continuing Operations	53	785	20	204	$105.58	$3.18	$56.65
Six Months Ended June 30, 2012							
United States	44	432	16	132	$97.70	$2.36	$37.46
Equatorial Guinea (2)	35	222	—	72	111.38	0.27	—
Israel	—	84	—	14	—	4.84	—
China	5	—	—	5	120.93	—	—
Total Consolidated Operations	84	738	16	223	$104.70	$2.01	$37.46
Equity Investees (3)	2	—	5	7	110.05	—	65.57
Total Continuing Operations	86	738	21	230	$104.80	$2.01	$44.50
Six Months Ended June 30, 2011							
United States	37	380	14	114	$97.15	$4.14	$48.98
Equatorial Guinea (2)	12	240	—	52	108.57	0.27	—
Israel	—	157	—	26	—	4.54	—
China	4	—	—	4	102.61	—	—
Total Consolidated Operations	53	777	14	196	100.14	3.02	48.98

Equity Investees (3)	2	—	5	7	109.89	—	74.16
Total Continuing Operations	55	777	19	203	$100.46	$3.02	$56.06

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price differentials, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

(2) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an

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LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(3) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. See Income from Equity Method Investees below.

If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)			
	2012		2011	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended June 30,				
United States	$(0.26)	$0.41	$(6.67)	$0.67
Equatorial Guinea	(5.02)	—	—	—
Total Consolidated Operations	(2.16)	0.25	(4.82)	0.32
Total Continuing Operations	(2.14)	0.25	(4.64)	0.32
Six Months Ended June 30,				
United States	$(1.28)	$0.35	$(4.72)	$0.71
Equatorial Guinea	(6.45)	—	—	—
Total Consolidated Operations	(3.34)	0.20	(3.29)	0.35
Total Continuing Operations	(3.26)	0.20	(3.15)	0.35

An analysis of revenues from sales of crude oil, natural gas and NGLs is as follows:

	Sales Revenues			
	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
Three Months Ended June 30, 2011	$490	$226	$67	$783
Changes due to				
Increase (Decrease) in Sales Volumes	323	(23)	5	305
(Decrease) in Sales Prices	(44)	(86)	(24)	(154)
Three Months Ended June 30, 2012	$769	$117	$48	$934
Six Months Ended June 30, 2011	$951	$425	$124	$1,500
Changes due to				
Increase (Decrease) in Sales Volumes	568	(19)	20	569
Increase (Decrease) in Sales Prices	69	(136)	(32)	(99)
Six Months Ended June 30, 2012	$1,588	$270	$112	$1,970

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the second quarter and first six months of 2012 as compared with 2011 due to the following:

- higher sales volumes in the DJ Basin attributable to the acceleration of our horizontal drilling programs in the Wattenberg area;
- commencement of production at Galapagos and South Raton, in the deepwater Gulf of Mexico; and

- higher sales volumes in Equatorial Guinea due to the commencement of oil production at Aseng during the fourth quarter of 2011, which impacted our sales volumes by approximately 21 MBbl/d, net in the first six months of 2012 as compared with 2011;

partially offset by:

- reductions in sales volumes in the Wattenberg and Rocky Mountain areas of our US operations due to third-party processing facility maintenance and unseasonably warm weather;

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- decreases in average realized prices during the second quarter of 2012; and
- natural field decline in non-core onshore US and deepwater Gulf of Mexico areas.

Natural gas sales – Revenues from natural gas sales decreased during the second quarter and first six months of 2012 as compared with 2011 due to the following:

- decreases in total consolidated average realized prices primarily due to oversupply and above average levels of natural gas in storage in the US;
- reductions in sales volumes in the Wattenberg and Rocky Mountain areas of our US operations due to third-party processing facility maintenance and unseasonably warm weather;
- lower sales volumes in non-core onshore US and deepwater Gulf of Mexico areas due to natural field decline;
- lower sales volumes from the Alba field, offshore Equatorial Guinea, due to scheduled maintenance activities at the non-operated Alba facilities; and
- lower sales volumes in Israel due to a reduction in the rate of production from the Mari-B field in order to manage the reservoir;

partially offset by:

- higher sales volumes in the DJ Basin attributable to the acceleration of our horizontal drilling programs in the Wattenberg area; and
- sales volumes from Marcellus Shale producing properties which we acquired September 30, 2011 and current Marcellus Shale development activities, which added 71 MMcf/d, net to our sales volumes for the first six months of 2012.

NGL sales – Most of our US NGL production is from the Wattenberg area. NGL sales revenues decreased during the second quarter and first six months of 2012 as compared with 2011 due to a decline in the average realized sales prices caused by higher supplies of NGLs resulting from increased wet gas drilling activities, offset by increased sales volumes from the continued acceleration of our horizontal drilling programs.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities, and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore on Bioko Island in Equatorial Guinea. We also have a 50% interest in CONE Gathering LLC (CONE) which owns and operates the infrastructure associated with our Marcellus Shale joint venture. During the first six months of 2012, we contributed $35 million to CONE.

Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, our share of dividends is reported within cash flows from operating activities and our share of investments is reported within cash flows from investing activities.

The decrease in income from equity method investees for the second quarter and first six months of 2012 as compared with 2011 was due to decreases in average realized liquids prices and lower second quarter 2012 sales volumes resulting from scheduled maintenance downtime, offset by higher methanol sales prices. See Oil, Gas and NGL Sales table above.

Methanol sales volumes and prices were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011

Methanol Sales Volumes (Mmgal)	36	39	77	78
Methanol Sales Prices (per gallon)	$1.09	$1.01	$1.06	$1.02

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Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2012	2011	Increase (Decrease) from Prior Year
Three Months Ended June 30,			
Production Expense	$169	$137	23 %
Exploration Expense	167	67	149 %
Depreciation, Depletion and Amortization	325	211	54 %
General and Administrative	96	82	17 %
Asset Impairments	73	131	(44)%
Other Operating (Income) Expense, Net	(2)	(11)	(82)%
Total	$828	$617	34 %
Six Months Ended June 30,			
Production Expense	$334	$264	27 %
Exploration Expense	227	137	66 %
Depreciation, Depletion and Amortization	619	404	53 %
General and Administrative	193	164	18 %
Asset Impairments	73	137	(47)%
Other Operating (Income) Expense, Net	10	18	(44)%
Total	$1,456	$1,124	30 %

Changes in operating costs and expenses are discussed below.

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Production Expense Components of production expense were as follows:

	Total per BOE [1]	Total	United States	Equatorial Guinea	Israel	Other Int'l, Corporate
(millions, except unit rate)						
Three Months Ended June 30, 2012						
Lease Operating Expense [2]	$5.02	$100	$68	$20	$3	$9
Production and Ad Valorem Taxes	2.21	44	33	—	—	11
Transportation and Gathering Expense	1.27	25	24	—	—	1
Total Production Expense	$8.50	$169	$125	$20	$3	$21
Three Months Ended June 30, 2011						
Lease Operating Expense [2]	$4.67	$83	$60	$14	$4	$5
Production and Ad Valorem Taxes	2.10	39	28	—	—	11
Transportation and Gathering Expense	0.88	15	14	—	—	1
Total Production Expense	$7.65	$137	$102	$14	$4	$17
Six Months Ended June 30, 2012						
Lease Operating Expense [2]	$5.07	$205	$139	$43	$7	$16
Production and Ad Valorem Taxes	2.01	81	59	—	—	22
Transportation and Gathering Expense	1.16	48	45	—	—	3
Total Production Expense	$8.24	$334	$243	$43	$7	$41
Six Months Ended June 30, 2011						
Lease Operating Expense [2]	$4.61	$163	$122	$23	$7	$11
Production and Ad Valorem Taxes	1.96	70	52	—	—	18
Transportation and Gathering Expense	0.87	31	30	—	—	1
Total Production Expense	$7.44	$264	$204	$23	$7	$30

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

(2) Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover expense.

For the second quarter and first six months of 2012, total production expense increased as compared with 2011 due to the following:

- an increase in US lease operating, transportation and gathering expenses due to higher sales volumes from the Wattenberg area due to ongoing development activities and new production from the Marcellus Shale joint venture;
- an increase in US taxes of approximately $6 million, of which approximately $4 million related to wells spud prior to 2012, due to the enactment of the annual Marcellus Shale well impact fee by the Pennsylvania legislature in first quarter 2012;
- an increase in Equatorial Guinea lease operating expense associated with the Aseng field which began producing in November 2011; and
- an increase in China taxes due to increases in sales volumes and prices.

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Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa [1]	Eastern Mediterranean [2]	Other Int'l, Corporate [3]
Three Months Ended June 30, 2012					
Dry Hole Cost	$117	$116	$1	$—	$—
Seismic	17	13	—	—	4
Exploration Expense	28	4	2	1	21
Other	5	4	—	—	1
Total Exploration Expense	$167	$137	$3	$1	$26
Three Months Ended June 30, 2011					
Dry Hole Cost	$23	$(2)	$25	$—	$—
Seismic	13	7	1	3	2
Exploration Expense	24	7	2	—	15
Other	7	7	—	—	—
Total Exploration Expense	$67	$19	$28	$3	$17
Six Months Ended June 30, 2012					
Dry Hole Cost	$118	$116	$2	$—	$—
Seismic	46	39	—	—	7
Exploration Expense	52	8	4	2	38
Other	11	10	1	—	—
Total Exploration Expense	$227	$173	$7	$2	$45
Six Months Ended June 30, 2011					
Dry Hole Cost	$45	$20	$25	$—	$—
Seismic	39	23	1	3	12
Exploration Expense	42	12	3	—	27
Other	11	11	—	—	—
Total Exploration Expense	$137	$66	$29	$3	$39

(1) West Africa includes Equatorial Guinea, Cameroon, and Senegal/Guinea-Bissau.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other International includes various international new ventures such as offshore Nicaragua.

Exploration expense for the second quarter and first six months of 2012 included the following:

- dry hole cost related primarily to the Deep Blue exploratory well (deepwater Gulf of Mexico). Although Deep Blue was successful in locating hydrocarbons, we decided not to develop the prospect due to near-term lease expiration as well as other considerations;
- acquisition of seismic information for the deepwater Gulf of Mexico lease sale; and
- staff expense associated with new ventures and corporate expenditures.

Exploration expense for the second quarter and first six months of 2011 included the following:

- dry hole cost associated with exploratory drilling in the US Rocky Mountain area and offshore Senegal/Guinea-Bissau;

- acquisition of seismic information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, and international new ventures; and
- staff expense associated with new ventures and corporate expenditures.

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Depreciation, Depletion and Amortization DD&A expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
DD&A Expense (millions) [1]	$325	$211	$619	$404
Unit Rate per BOE [2]	$16.37	$11.80	$15.26	$11.38

[1] For DD&A expense by geographical area, see Item 1. Financial Statements – Note 12. Segment Information.
[2] Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for the second quarter and first six months of 2012 increased as compared with 2011 due to the following:

- higher sales volumes in the DJ Basin onshore US and the addition of DD&A expense related to the Marcellus Shale joint venture;
- the start up of Galapagos and South Raton in the deepwater Gulf of Mexico;
- the startup of the Aseng field which includes the Aseng FPSO in its depreciation base;

partially offset by:

- lower sales volumes in non-core onshore US and deepwater Gulf of Mexico areas resulting from natural field decline.

Changes in the unit rate per BOE for the second quarter and first six months of 2012 as compared with 2011 were due to changes in the mix of production, primarily due to volumes from the start-up of the Aseng field, which has a higher DD&A rate.

General and Administrative Expense General and administrative expense (G&A) was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
G&A Expense (millions)	$96	$82	$193	$164
Unit Rate per BOE [1]	$4.84	$4.57	$4.77	$4.61

[1] Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

G&A expense for the second quarter and first six months of 2012 increased as compared with 2011 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

Asset Impairment Expense Asset impairment expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Asset Impairments	$73	$131	$73	$137

See Item 1. Financial Statements – Note 4. Asset Impairments.

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Other Operating (Income) Expense, Net Other operating (income) expense, net was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Deepwater Gulf of Mexico Moratorium Expense	$—	$1	$—	$19
Electricity Generation Expense	—	9	—	26
Gain on Divestitures	(9)	(25)	(9)	(26)
Other, Net	7	4	19	(1)
Total	$(2)	$(11)	$10	$18

See Item 1. Financial Statements – Note 2. Basis of Presentation.

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
(Gain) Loss on Commodity Derivative Instruments	$(276)	$(143)	$(180)	$143
Interest, Net of Amount Capitalized	27	21	59	37
Other Non-Operating (Income) Expense, Net	(3)	(9)	(3)	—
Total	$(252)	$(131)	$(124)	$180

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments is a result of mark-to-market accounting. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions, except unit rate)				
Interest Expense	$69	$49	$138	$90
Capitalized Interest	(42)	(28)	(79)	(53)
Interest Expense, Net	$27	$21	$59	$37
Unit Rate per BOE (1)	$1.35	$1.19	$1.44	$1.05

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Interest expense prior to the reduction for capitalized interest increased for the second quarter and first six months of 2012 as compared with 2011. The increase mainly resulted from our December 2011 debt issuance, an additional month of interest for our February 2011 debt issuance and interest related to our Aseng FPSO lease obligation.

The increase in capitalized interest is mainly due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and offshore Israel.

Other Non-Operating (Income) Expense, Net   Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income, transaction (gains) losses, and other (income) expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Income Tax Provision

See Item 1. Financial Statements – Note 11. Income Taxes for a discussion of the change in our effective tax rate for the second quarter and first six months of 2012 as compared with 2011.

Discontinued Operations

Summarized results of discontinued operations were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
millions				
Oil and Gas Sales	$65	$112	$140	$225
Less:				
Production Expense	11	18	25	32
DD&A Expense	14	24	32	52
Other Operating (Income) Expense, Net	1	1	4	4
Income Before Income Taxes	39	69	79	137
Income Tax Expense	22	44	47	64
Income From Discontinued Operations	$17	$25	$32	$73
Key Statistics:				
Daily Production				
Crude Oil & Condensate (MBbl/d)	6	10	6	10
Natural Gas (MMcf/d)	4	6	5	7
Average Realized Price				
Crude Oil & Condensate (Per Bbl)	$109.66	$119.61	$116.14	$112.47
Natural Gas (Per Mcf)	8.84	8.28	8.29	7.74

Our long-term debt is recorded at the consolidated level and is not reflected by each component. Thus, we have not allocated interest expense to discontinued operations.

See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our major development projects, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives. We also utilize a commodity price hedging program to reduce the impacts of commodity price volatility and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and operations.

Our current line-up of major development projects, as well as our planned exploration and appraisal drilling activities, may result in capital expenditures exceeding cash flows from operating activities during the near term. However, we expect that new incremental production from our current projects, some of which are expected to commence as early as 2013, combined with higher production resulting from our Horizontal Niobrara and Marcellus Shale development programs, will result in a substantial increase in cash flows from operating activities. We believe we are well-positioned to fund these long-term growth plans. See Available Liquidity, below.

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In addition, we are currently evaluating potential development scenarios for our significant natural gas discoveries offshore Eastern Mediterranean, including Leviathan and Cyprus Block 12. The magnitude of these discoveries presents financial and technical challenges for us due to the large-scale development requirements. Potential development scenarios include the construction of LNG terminals, floating LNG, subsea pipeline or other options. Each of these development options would require a multi-billion dollar investment and require a number of years to complete. As a result, we will likely seek partners to provide technical and financial support as well as midstream and downstream expertise.

Traditional sources of our liquidity are cash on hand, cash flows from operations, available borrowing capacity under our credit facility, and proceeds from sales of non-core properties, such as our pending sales of certain North Sea and onshore US properties. We may also access debt and/or capital markets for additional financing, such as an issuance of long-term debt, for our large development projects. We also have the option to increase our Credit Facility's overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

Available Liquidity   Information regarding cash and debt balances was as follows:

	June 30, 2012		December 31, 2011	
(millions, except percentages)				
Cash and Cash Equivalents	$702		$1,455	
Amount Available to be Borrowed Under Credit Facility [1]	3,000		3,000	
Total Liquidity	$3,702		$4,455	
Total Debt [2]	$4,473		$4,495	
Total Shareholders' Equity	7,805		7,265	
Ratio of Debt-to-Book Capital [3]	36	%	38	%

(1) See Credit Facility below.

(2) Total debt includes Aseng FPSO lease obligation and remaining CONSOL installment payments and excludes unamortized debt discount.

(3) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders’ equity.

Cash and Cash Equivalents   We had approximately $702 million in cash and cash equivalents at June 30, 2012, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $630 million of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently expect to use a significant amount of cash during 2012 to fund international projects, including the planned developments in West Africa and the Eastern Mediterranean.

Credit Facility   We have an unsecured revolving credit facility that matures on October 14, 2016. The commitment is $3.0 billion through the maturity date of the credit facility. See Financing Activities – Long-Term Debt below.

Derivative Instruments   We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments include variable to fixed price commodity swaps, two and three-way collars and basis swaps. Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. None of our counterparty agreements contain margin requirements. We have also used derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. However, we currently have no interest rate derivative instruments.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of June 30, 2012, the fair value of our commodity derivative assets was $170 million and the fair value of our commodity derivative liabilities was $2 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities for a discussion of derivative counterparty credit risk and Note 7. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

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European Debt Crisis The European debt crisis continues to have a negative impact on the European economy, with risks to the global financial system and overall global economy. On June 21, 2012, Moody's Investors Service downgraded the credit ratings of many international banks due to their exposure to the continuing European debt crisis which is causing extreme volatility and weakening of the global financial markets. Many of the banks receiving credit rating downgrades are counterparties in our commodity hedging program, as well as lenders in our $3.0 billion Credit Facility. Further credit downgrades of these institutions could result in a change in our counterparties with whom we execute hedging transactions according to our internal risk guidelines. In addition, with continued Eurozone instability, some of our Credit Facility banks more stressed by the crisis may be reluctant to increase their lending commitments to us should we desire to expand our Credit Facility capacity. At this time, we believe our current balance sheet and financial flexibility enhance our ability to react to Eurozone events as they unfold.

Counterparty Credit Risk   We monitor the creditworthiness of our trade creditors, joint venture partners, hedging counterparties, and financial institutions on an ongoing basis. Some of these entities are not as creditworthy as we are and may experience credit downgrades, as noted above, or liquidity problems. Credit downgrades or liquidity problems could result in a delay in our receiving proceeds from commodity sales or reimbursement of joint venture costs.

The current uncertain economic and commodity price environment increases the risk of a sudden negative change in liquidity, which could impair a party's ability to perform under the terms of a contract. We are unable to predict sudden changes in a party's creditworthiness or ability to perform. Even if we do accurately predict such sudden changes, our ability to negate these risks may be limited and we could incur significant financial losses.

In addition, nonoperating partners often must obtain financing for their share of capital cost for development projects. For example, our Eastern Mediterranean partners must obtain financing for their share of significant development expenditures at Tamar and Leviathan, which potentially includes an LNG project and/or major underwater pipeline. A partner's inability to obtain financing could result in a delay of one of our joint development projects.

Credit enhancements have been obtained from some parties in the form of parental guarantees or letters of credit; however, not all of our counterparty credit is protected through guarantees or credit support. Nonperformance by a trade creditor, joint venture partner, hedging counterparty or financial institution could result in significant financial losses.

Contractual Obligations

CONSOL Carried Cost Obligation The CONSOL Carried Cost Obligation represents our agreement to fund up to approximately $2.1 billion of CONSOL’s future drilling and completion costs. The CONSOL Carried Cost Obligation is expected to extend over approximately eight years. It is capped at $400 million in each calendar year and is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. Therefore, specific payment dates for the funding of the CONSOL Carried Cost Obligation cannot be determined at this time. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. Based on the June 30, 2012 Henry Hub natural gas price curve, we forecast our CONSOL Carried Cost Obligation will remain suspended for the next 12 months.

Cash Flows

Cash flow information is as follows:

	Six Months Ended June 30,	
	2012	2011
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$1,247	$1,229
Investing Activities	(1,925)	(1,184)
Financing Activities	(75)	401
Increase (Decrease) in Cash and Cash Equivalents	$(753)	$446

Operating Activities Net cash provided by operating activities for the first six months of 2012 remained flat as compared with 2011. Higher liquids sales volumes were offset by decreases in natural gas sales volumes and prices and increases in production expenses, general and administrative expense and interest expense. See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions. Capital spending for property, plant and equipment increased by $639 million during the first six months of 2012 as compared with 2011, primarily due to increased major project development activity in the Wattenberg area, the Marcellus Shale, offshore West Africa, and offshore Israel. We also invested $35 million in CONE during the first six months of 2012. In addition, we received $10 million proceeds from US onshore divestitures during the first six months of 2012 as compared with $77 million proceeds, $73 million of which related to our transfer of Ecuador assets to the government of Ecuador, during the first six months of 2011.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first six months of 2012, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($39 million). We used cash to pay dividends on our common stock ($79 million), make principal payments related to the Aseng FPSO capital lease obligation ($22 million) and repurchase shares of our common stock ($13 million).

In comparison, during the first six months of 2011, funds were provided by net cash proceeds from borrowings under our revolving credit facility ($120 million) and the issuance of 6% senior notes due 2041 ($836 million). Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($35 million). We used a portion of the proceeds from the issuance of senior notes to repay amounts outstanding under our credit facility ($470 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($64 million) and repurchase shares of our common stock ($16 million).

See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities

Acquisition, Capital and Exploration Expenditures   Information for investing activities (on an accrual basis) is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(millions)				
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$14	$42	$87	$57
Exploration	92	106	221	228
Development	719	500	1,454	874
Corporate and Other	13	54	25	88
Total	$838	$702	$1,787	$1,247
Other				
Investment in Equity Method Investee	$21	$—	$35	$—
Increase in FPSO Lease Obligation	—	17	—	51

2012   Unproved property acquisition costs primarily related to an acquisition that strengthened our position in the DJ Basin along with other miscellaneous onshore US lease acquisitions. The increase in development costs is due to increased capital spending on major development projects located in the DJ Basin, Marcellus Shale, offshore Equatorial Guinea and offshore Israel.

2011 Unproved property acquisition costs for the first six months of 2011 related to onshore US lease acquisitions.

Financing Activities

Long-Term Debt Our principal source of liquidity is an unsecured revolving credit facility that matures October 14, 2016. We did not engage in any activities under the Credit Facility, or other short-term borrowing arrangements during the first six months of 2012.

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The Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (ii) will mature on October 14, 2016, (iii) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (iv) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (v) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 100 basis points to 145 basis points depending upon our credit rating.

At June 30, 2012, there were no borrowings outstanding under the Credit Facility, leaving $3.0 billion available for use. We expect to use the Credit Facility to fund our capital investment program, and we periodically borrow amounts under provision (iv) above for working capital purposes. See Item 1. Financial Statements – Note 5. Debt.

Our outstanding fixed-rate debt, excluding the Aseng FPSO lease obligation and unamortized debt discount, totaled approximately $4.1 billion at June 30, 2012. The weighted average interest rate on fixed-rate debt was 5.57%, with maturities ranging from 2012 to 2097. Approximately 21% of our fixed rate debt will mature within the next five years.

Dividends We paid total cash dividends of 44 cents per share of our common stock during the first six months of 2012 and 36 cents per share during the first six months of 2011. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options We received cash proceeds from the exercise of stock options of $26 million during the first six months of 2012 and $26 million during the first six months of 2011.

Common Stock Repurchases We receive shares of common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received 132,484 shares with a value of $13 million during the first six months of 2012 and 180,538 shares with a value of $16 million during the first six months of 2011.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to market risk in the normal course of business operations, and the volatility of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to price changes.

At June 30, 2012, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net receivable position with a fair value of $168 million. Based on the June 30, 2012 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately $19 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately $4 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item

1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our revolving credit facility and the amount of interest we earn on our short-term investments.

At June 30, 2012, we had approximately $4.1 billion (excluding the Aseng FPSO lease obligation and unamortized debt discount) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 5.57%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 1. Financial Statements – Note 5. Debt.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure

to interest rate risk. Changes in fair value of interest rate derivative instruments used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At June 30, 2012, AOCL included $26 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified to earnings as adjustments to interest expense over the terms of our
5¼% senior notes due April 15, 2014 and 6% senior notes due March 1, 2041. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of June 30, 2012, our cash and cash equivalents totaled approximately $702 million, approximately 59% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of June 30, 2012 would result in a change in annual interest income of approximately $1 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

Net transaction losses were $9 million for the second quarter of 2012 and $6 million for the six months ended June 30, 2012, and were de minimis for 2011. The losses were primarily related to the changes in exchange rates between the US dollar and Israeli new shekel. Transaction (gains) losses are included in other (income) expense, net in the consolidated statements of operations.

We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

Disclosure Regarding Forward-Looking Statements

This quarterly report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions;
-

the impact of governmental fiscal terms and/or regulation, such as that involving the protection of the environment or marketing of production, as well as other regulations; and

- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors included herein, if any, and included in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and our Annual Report on Form 10-K for the year ended December 31, 2011, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2011 is available on our

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website at www.nobleenergyinc.com.

Item 4. Controls and Procedures

Based on the evaluation of our disclosure controls and procedures by our principal executive officer and our principal financial officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective. There were no changes in internal control over financial reporting that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

COGCC During 2011, we received two Notices of Alleged Violation (NOAV) from the Colorado Oil and Gas Conservation Commission (COGCC) regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. We are in ongoing discussions with the COGCC in an effort to favorably resolve this matter but we are unable to predict the ultimate outcome at this time. However, we believe that the final resolution will not have a material adverse effect on our financial position, results of operations or cash flows.

See Item 1. Financial Statements – Note 13. Commitments and Contingencies.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 or Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2011.

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

The following table sets forth, for the periods indicated, the Company’s share repurchase activity:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
04/01/2012 - 04/30/2012	295	$94.26	—	—
05/01/2012 - 05/31/2012	219	97.04	—	—
06/01/2012 - 06/30/2012	102	81.63	—	—
Total	616	$93.16	—	—

(1)

Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under stock-based compensation plans.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

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None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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Signatures

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

	NOBLE ENERGY, INC. (Registrant)
Date July 26, 2012	/s/ Kenneth M. Fisher Kenneth M. Fisher Senior Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Incorporation of the Registrant (as amended through May 25, 2012), filed herewith.
3.2	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 20, 2009 and incorporated herein by reference).
31.1	Certification of the Company's Chief Executive Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	Certification of the Company's Chief Financial Officer Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	Certification of the Company's Chief Executive Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	Certification of the Company's Chief Financial Officer Pursuant To Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document