NOBLE ENERGY INC
Form 10-Q
October 25, 2012
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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 September 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 October 9, 2012, there were 177,890,973 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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues				
Oil, Gas and NGL Sales	$954	$829	$2,925	$2,328
Income from Equity Method Investees	51	50	137	146
Other Revenues	1	—	—	33
Total	1,006	879	3,062	2,507
Costs and Expenses				
Production Expense	158	142	492	406
Exploration Expense	95	56	322	193
Depreciation, Depletion and Amortization	368	215	987	619
General and Administrative	93	89	286	253
(Gain) Loss on Divestitures	(157)	—	(167)	(26)
Asset Impairments	—	—	73	137
Other Operating (Income) Expense, Net	(1)	2	19	45
Total	556	504	2,012	1,627
Operating Income	450	375	1,050	880
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	135	(322)	(46)	(179)
Interest, Net of Amount Capitalized	36	14	95	51
Other Non-Operating (Income) Expense, Net	4	(16)	2	(16)
Total	175	(324)	51	(144)
Income from Continuing Operations Before Income Taxes	275	699	999	1,024
Income Tax Provision	111	208	312	297
Income from Continuing Operations	164	491	687	727
Discontinued Operations, Net of Tax	57	(50)	89	22
Net Income	$221	$441	$776	$749
Earnings Per Share, Basic				
Income from Continuing Operations	$0.92	$2.78	$3.87	$4.11
Discontinued Operations, Net of Tax	0.32	(0.28)	0.50	0.14
Net Income	$1.24	$2.50	$4.37	$4.25
Earnings Per Share, Diluted				
Income from Continuing Operations	$0.91	$2.67	$3.81	$3.99
Discontinued Operations, Net of Tax	0.32	(0.28)	0.49	0.13
Net Income	$1.23	$2.39	$4.30	$4.12
Weighted Average Number of Shares Outstanding				
Basic	178	177	178	176
Diluted	180	180	180	179

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Income	$221	$441	$776	$749
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	3	1	6	4
Other Comprehensive Income	3	1	6	19
Comprehensive Income	$224	$442	$782	$768

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

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

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,617	$1,455
Accounts Receivable, Net	686	783
Other Current Assets	422	180
Total Current Assets	2,725	2,418
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	18,422	19,057
Property, Plant and Equipment, Other	335	294
Total Property, Plant and Equipment, Gross	18,757	19,351
Accumulated Depreciation, Depletion and Amortization	(5,882)	(6,569)
Total Property, Plant and Equipment, Net	12,875	12,782
Goodwill	635	696
Other Noncurrent Assets	625	548
Total Assets	$16,860	$16,444
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,243	$1,343
Other Current Liabilities	1,014	925
Total Current Liabilities	2,257	2,268
Long-Term Debt	3,747	4,100
Deferred Income Taxes, Noncurrent	2,157	2,059
Other Noncurrent Liabilities	691	752
Total Liabilities	8,852	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	3,244	2,497
Accumulated Other Comprehensive Loss	(94)	(100)
Treasury Stock, at Cost; 19 Million Shares	(651)	(638)
Retained Earnings	5,507	4,850
Total Shareholders' Equity	8,008	7,265
Total Liabilities and Shareholders' Equity	$16,860	$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)

	Nine Months Ended September 30, 2012	2011
Cash Flows From Operating Activities		
Net Income	$776	$749
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,020	681
Asset Impairments	73	139
Dry Hole Cost	141	57
Deferred Income Taxes	57	147
Dividends (Income) from Equity Method Investees, Net	4	23
Unrealized Gain on Commodity Derivative Instruments	(74)	(140)
Gain on Divestitures	(83)	(26)
Other Adjustments for Noncash Items Included in Income	115	52
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	68	(7)
Increase in Other Current Assets	(51)	(17)
Increase in Accounts Payable	122	131
Increase in Current Income Taxes Payable	51	52
Decrease in Other Current Liabilities	(13)	(25)
Other Operating Assets and Liabilities, Net	(35)	(31)
Net Cash Provided by Operating Activities	2,171	1,785
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(2,685)	(1,868)
Marcellus Shale Acquisition	—	(519)
Additions to Equity Method Investments	(35)	(73)
Proceeds from Divestitures	1,161	77
Net Cash Used in Investing Activities	(1,559)	(2,383)
Cash Flows From Financing Activities		
Exercise of Stock Options	28	32
Excess Tax Benefits from Stock-Based Awards	14	11
Dividends Paid, Common Stock	(119)	(104)
Purchase of Treasury Stock	(13)	(16)
Proceeds from Credit Facilities	150	520
Repayment of Credit Facilities	(150)	(470)
Repayment of CONSOL Installment Loan	(328)	—
Proceeds from Issuance of Senior Long-Term Debt, Net	—	836
Settlement of Interest Rate Derivative Instrument	—	(40)
Repayment of Capital Lease Obligation	(32)	—
Net Cash Provided By (Used In) Financing Activities	(450)	769
Increase in Cash and Cash Equivalents	162	171
Cash and Cash Equivalents at Beginning of Period	1,455	1,081
Cash and Cash Equivalents at End of Period	$1,617	$1,252

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	—	—	—	—	776	776
Stock-based Compensation	—	51	—	—	—	51
Exercise of Stock Options	—	28	—	—	—	28
Tax Benefits Related to Exercise of Stock Options	—	14	—	—	—	14
Dividends (66 cents per share)	—	—	—	—	(119)	(119)
Changes in Treasury Stock, Net	—	—	—	(13)	—	(13)
Change in Par Value	(654)	654		—	—	—
Net Change in Other	—	—	6	—	—	6
September 30, 2012	$2	$3,244	$(94)	$(651)	$5,507	$8,008
December 31, 2010	$651	$2,385	$(104)	$(624)	$4,540	$6,848
Net Income	—	—	—	—	749	749
Stock-based Compensation	—	43	—	—	—	43
Exercise of Stock Options	2	30	—	—	—	32
Tax Benefits Related to Exercise of Stock Options	—	11	—	—	—	11
Dividends (58 cents per share)	—	—	—	—	(104)	(104)
Changes in Treasury Stock, Net	—	—	—	(16)	—	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	—	—	15	—	—	15
Net Change in Other	2	(2)	4	—	—	4
September 30, 2011	$655	$2,467	$(85)	$(640)	$5,185	$7,582

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 September 30, 2012 and December 31, 2011 and for the three and nine months ended September 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 nine months ended September 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. Commodity prices have been volatile during 2012. Such volatility results in increased uncertainty inherent in our estimates and assumptions. Declines in commodity prices during the fourth quarter of 2012 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.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Other Revenues (1)	$1	$—	$—	$33
Production Expense				
Lease Operating Expense	$103	$89	$309	$251
Production and Ad Valorem Taxes	31	38	112	108
Transportation and Gathering Expense	24	15	71	47
Total	$158	$142	$492	$406
Other Operating (Income) Expense, Net				
Deepwater Gulf of Mexico Moratorium Expense (2)	$—	$(1)	$—	$18
Electricity Generation Expense (1)	—	—	—	26
Other, Net	(1)	3	19	1
Total	$(1)	$2	$19	$45
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (Income) Expense (3)	$7	$(18)	$(1)	$(15)
Interest Income	(1)	(2)	(1)	(7)
Other (Income) Expense, Net	(2)	4	4	6
Total	$4	$(16)	$2	$(16)

(1) Other revenues consist primarily 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) Amounts relate 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)	September 30, 2012	December 31, 2011
Accounts Receivable, Net		
Commodity Sales	$264	$356
Joint Interest Billings	295	313
Other	136	123
Allowance for Doubtful Accounts	(9)	(9)
Total	$686	$783
Other Current Assets		
Inventories, Current	$88	$78
Commodity Derivative Assets	35	10
Deferred Income Taxes, Net (1)	104	41
Probable Insurance Claims (2)	39	15
Assets Held for Sale (3)	73	—
Prepaid Expenses and Other Current Assets	83	36
Total	$422	$180
Other Noncurrent Assets		
Equity Method Investments	$363	$329
Mutual Fund Investments	110	99
Commodity Derivative Assets	24	37
Other Assets, Noncurrent	128	83
Total	$625	$548
Other Current Liabilities		
Production and Ad Valorem Taxes	$117	$121
Commodity Derivative Liabilities	16	76
Income Taxes Payable	209	127
Asset Retirement Obligations	41	33
Interest Payable	40	56
CONSOL Installment Payment (4)	322	324
Current Portion of FPSO Lease Obligation	48	45
Liabilities Associated with Assets Held for Sale (3)	34	—
Other	187	143
Total	$1,014	$925
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$237	$222
Asset Retirement Obligations	279	344
Accrued Benefit Costs	88	88
Commodity Derivative Liabilities	5	7
Other	82	91
Total	$691	$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) Assets held for sale consists primarily of oil and gas properties and liabilities held for sale consists primarily of asset retirement obligations.

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

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 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

Sale of North Sea Properties On August 13, 2012, we closed the sale of our 30% non-operated working interest in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea. Proceeds from the transaction were $117 million, and included final closing adjustments from the effective date of January 1, 2012. The net book value of assets sold was $256 million. Asset retirement obligations associated with the sale were $55 million. We reversed a deferred tax liability and recognized a corresponding income tax benefit of $106 million when the sale closed.
We continue to market our remaining North Sea properties. As of September 30, 2012, all the properties remaining in our North Sea geographical segment are included in assets held for sale in our consolidated balance sheet. 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.
Summarized results of discontinued operations are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Oil and Gas Sales	$54	$45	$194	$271
Income Before Income Taxes	38	23	117	161
Income Tax Expense	3	73	50	139
Operating Income (Loss), Net of Tax	35	(50)	67	22
Gain on Sale, Net of Tax	22	—	22	—
Discontinued Operations, Net of Tax	$57	$(50)	$89	$22

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Sale of Onshore US Properties During the third quarter of 2012, we closed the sales of certain crude oil and natural gas properties in Kansas, western Oklahoma, western Texas, and the Texas Panhandle with an effective date of April 1, 2012. Additionally, in June 2012, we closed the sale of certain non-core assets located in Wyoming. The information regarding the assets sold is as follows:

(millions)	Nine Months Ended September 30, 2012
Cash Proceeds	$1,044
Less	
Net Book Value of Assets Sold	(838)
Goodwill Allocated to Assets Sold	(61)
Asset Retirement Obligations Associated with Assets Sold	20
Other Closing Adjustments	2
Gain on Divestitures	$167

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 $938 million as of September 30, 2012, including the first payment under an installment loan. The second payment under the installment loan will be paid in 2013. 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). 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 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:

(millions)	September 30, 2012
Unproved Oil and Gas Properties	$803
Proved Oil and Gas Properties	386
Investment in CONE Gathering LLC	69
Total Assets Acquired [1]	$1,258

[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.

Note 4. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

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

2012 During the second quarter of 2012, we determined that the carrying amounts of our South Raton and Piceance developments were not recoverable from future cash flows and were impaired. The South Raton and Piceance impairments were primarily due to declines in near-term crude oil and natural gas prices, respectively. 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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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 5. Debt

Our debt consists of the following:

(millions, except percentages)	September 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	328	1.79	% [2]	656	1.76	% [2]
FPSO Lease Obligation	322	—		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	4,134			4,495		
Unamortized Discount	(17)			(26)		
Total Debt, Net of Discount	4,117			4,469		
Less Amounts Due Within One Year						
Current portion of CONSOL Installment Payment, net of discount	(322)			(324)		
FPSO Lease Obligation	(48)			(45)		
Long-Term Debt Due After One Year	$3,747			$4,100		

(1) Our Credit Agreement provides for a $4.0 billion unsecured 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.

On September 28, 2012 we exercised our option to increase the Credit Facility's overall commitment amount from $3.0 billion to $4.0 billion. Debt issuance costs of approximately $4 million were incurred and are being amortized to expense over the remaining term of the Credit Facility.

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

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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 marked to market, 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.

Unsettled Derivative Instruments   As of September 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 September 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	11,000	90.26	—	—	—
2014	Swaps	Dated Brent	8,000	105.94	—	—	—
2014	Three-Way Collars	NYMEX WTI	4,000	—	77.00	92.00	106.13
2014	Three-Way Collars	Dated Brent	10,000	—	85.00	98.50	129.24

[1] West Texas Intermediate

As of September 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 September 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
2014	Three-Way Collars	NYMEX HH	55,000	—	2.50	3.50	5.25

[1] Henry Hub

As of September 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			
	September 30, 2012		December 31, 2011		September 30, 2012		December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)								
Commodity Derivative Instruments	Current Assets	$35	Current Assets	$10	Current Liabilities	$16	Current Liabilities	$76
	Noncurrent Assets	24	Noncurrent Assets	37	Noncurrent Liabilities	5	Noncurrent Liabilities	7
Total		$59		$47		$21		$83

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Realized Mark-to-Market (Gain) Loss	$4	$(22)	$28	$(39)
Unrealized Mark-to-Market (Gain) Loss	131	(300)	(74)	(140)
Total (Gain) Loss on Commodity Derivative Instruments	$135	$(322)	$(46)	$(179)

AOCL at September 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 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)					
September 30, 2012					
Financial Assets					
Mutual Fund Investments	$110	$—	$—	$—	$110
Commodity Derivative Instruments	—	102	—	(43)	59
Financial Liabilities					
Commodity Derivative Instruments	—	(64)	—	43	(21)
Portion of Deferred Compensation Liability Measured at Fair Value	(169)	—	—	—	(169)
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.

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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:

	Fair Value Measurements Using				
Description	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 September 30, 2012					
Impaired Oil and Gas Properties	$—	$—	$—	$—	$—
Three Months Ended September 30, 2011					
Impaired Oil and Gas Properties	—	—	—	—	—
Nine Months Ended September 30, 2012					
Impaired Oil and Gas Properties	—	—	172	245	73
Nine Months Ended September 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 were discounted at the prevailing market rates for similar debt instruments. 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:

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount [1]	$3,795	$4,500	$4,114	$4,733

(1) Excludes Aseng FPSO lease obligation. No floating rate debt was outstanding at September 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.

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

(millions)	Nine Months Ended September 30, 2012
Capitalized Exploratory Well Costs, Beginning of Period	$696
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	164
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(27)
Capitalized Exploratory Well Costs Charged to Expense [1]	(108)
Other [2]	(19)
Capitalized Exploratory Well Costs, End of Period	$706

[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 decided not to proceed with additional appraisal activities.
[2] Amount represents the Selkirk exploratory well (North Sea) which, along with our other 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)	September 30, 2012	December 31, 2011
Exploratory Well Costs Capitalized for a Period of One Year or Less	$301	$318
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	405	378
Balance at End of Period	$706	$696
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	9	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 September 30, 2012:

		Suspended Since		
	Total	2011	2010	2009 & Prior
(millions)				
Country/Project:				
Offshore Equatorial Guinea				
Blocks O and I	$156	$44	$6	$106
Offshore Cameroon				
YoYo	45	5	2	38
Offshore Israel				
Leviathan	78	37	41	—
Leviathan-1 Deep	28	28	—	—
Dalit	22	—	1	21
Offshore Cyprus				
Cyprus A-1	10	10	—	—
Deepwater Gulf of Mexico				
Gunflint	54	—	—	54
Other				
2 projects of $10 million or less each	12	6	6	—
Total	$405	$130	$56	$219

Blocks O and I   Blocks O and I include crude oil, natural gas and natural gas condensate discoveries, such as: Felicita, a 2008 condensate and natural gas discovery on Block O, Diega, a 2008 condensate and oil discovery on Block I, and Carmen, a 2009 oil discovery on Block O. During 2011, we drilled a 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 oil discovery 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. We are also working with the government of Cameroon to assess gas commercialization options.

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, realization of full economic value of the resources 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 returned to the Leviathan-1 well and began drilling toward two deeper intervals in order to evaluate them 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. We have secured a rig with the capabilities necessary to reach the target objective and plan to begin drilling an exploratory well in late 2013.

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

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Cyprus During the fourth quarter of 2011, we drilled a successful natural gas exploration well (A-1) in Block 12. We submitted an appraisal plan to the Cyprus government during July 2012 and are reviewing locations for appraisal drilling activities.
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

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:

	Nine Months Ended September 30,	
	2012	2011
(millions)		
Asset Retirement Obligations, Beginning Balance	$377	$253
Liabilities Incurred	24	2
Liabilities Settled	(98)	(19)
Revision of Estimate	30	9
Accretion Expense	21	15
Other	(34)	—
Asset Retirement Obligations, Ending Balance	$320	$260

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

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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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions, except per share amounts)				
Income from Continuing Operations	$164	$491	$687	$727
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	—	(12)	(1)	(10)
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$164	$479	$686	$717
Weighted Average Number of Shares Outstanding, Basic	178	177	178	176
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	2	3	2	3
Weighted Average Number of Shares Outstanding, Diluted	180	180	180	179
Earnings from Continuing Operations Per Share, Basic	$0.92	$2.78	$3.87	$4.11
Earnings from Continuing Operations Per Share, Diluted	0.91	2.67	3.81	3.99
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	1	2	2

(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 September 30, 2011 and for the nine months ended September 30, 2012 and 2011 exclude deferred compensation gains, net of tax.

Note 11. Income Taxes

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Current	$37	$110	$138	$145
Deferred	74	98	174	152
Total Income Tax Provision	$111	$208	$312	$297
Effective Tax Rate	40%	30%	31%	29%

Our effective tax rate for the first nine months of 2012 increased as compared with the first nine months of 2011. This increase is primarily due to the establishment of a valuation allowance of $32 million with respect to foreign tax credits available, resulting in a corresponding increase in income tax expense. During the third quarter of 2012, we increased our reserve for uncertain tax positions related to prior years by $10 million, for a total year to date reserve of $23 million.

During the first nine months of 2011, we increased the valuation allowance against our deferred tax asset for foreign tax credits by $16 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, Sierra Leone and 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 September 30, 2012, our remaining North Sea properties were included in assets held for sale.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended September 30, 2012					
Revenues from Third Parties	$955	$594	$280	$48	$33
Income from Equity Method Investees	51	3	48	—	—
Total Revenues	1,006	597	328	48	33
DD&A	368	240	61	49	18
Gain on Divestitures [1]	(157)	(157)	—	—	—
Loss on Commodity Derivative Instruments [2]	135	42	93	—	—
Income (Loss) from Continuing Operations Before Income Taxes	275	337	85	(11)	(136)
Three Months Ended September 30, 2011					
Revenues from Third Parties	$829	$520	$153	$108	$48
Income from Equity Method Investees	50	—	50	—	—
Total Revenues	879	520	203	108	48
DD&A	215	180	13	8	14
Gain on Commodity Derivative Instruments [2]	(322)	(213)	(109)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	699	418	270	88	(77)
Nine Months Ended September 30, 2012					
Revenues from Third Parties	$2,925	$1,674	$995	$121	$135
Income from Equity Method Investees	137	6	131	—	—
Total Revenues	3,062	1,680	1,126	121	135
DD&A	987	670	196	64	57
Gain on Divestitures [1]	(167)	(167)	—	—	—
Asset Impairments [3]	73	73	—	—	—
(Gain) Loss on Commodity Derivative Instruments [2]	(46)	(60)	14	—	—
Income (Loss) from Continuing Operations Before Income Taxes	999	578	767	26	(372)
Nine Months Ended September 30, 2011					
Revenues from Third Parties	$2,361	$1,578	$401	$236	$146
Income from Equity Method Investees	146	—	146	—	—
Total Revenues	2,507	1,578	547	236	146
DD&A	619	534	30	19	36
Gain on Divestitures [1]	(26)	(1)	—	—	(25)
Asset Impairments [3]	137	137	—	—	—
Gain on Commodity Derivative Instruments [2]	(179)	(163)	(16)	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,024	631	460	184	(251)
September 30, 2012					
Goodwill	$635	$635	$—	$—	$—
Total Assets	16,787	11,014	2,782	2,443	548
December 31, 2011					
Goodwill	696	696	—	—	—
Total Assets	16,106	11,201	2,728	1,751	426

(1) See Note 3. Acquisitions and Divestitures.
(2) See Note 6. Derivative Instruments and Hedging Activities.
(3) See Note 4. Asset Impairments.

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Note 13. Commitments and Contingencies

Commitments During the third quarter of 2012, we entered into a 36-month drilling services contract with a subsidiary of Atwood Oceanics Inc. Drilling services will be provided by a new-build drillship, the Atwood Advantage, that will arrive at our first drilling location in the fourth quarter of 2013. The rate of $584,000 per day, gross, will begin upon arrival and will be allocated among joint venture partners.

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. In August 2012, we entered into an Administrative Order on Consent with COGCC resolving both NOAVs. In lieu of a fine payment, we agreed to institute a third party hydrogen sulfide awareness program with a total budget of up to $50,000 and arrange for the program to be completed by August 2013.

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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 third quarter of 2012 included:

- net income of $221 million, as compared with $441 million for third quarter 2011;
- loss on commodity derivative instruments of $135 million (including unrealized mark-to-market loss of $131 million) as compared with a gain on commodity derivative instruments of $322 million (including unrealized mark-to-market gain of $300 million) for third quarter 2011;
- diluted earnings per share of $1.23, as compared with $2.39 for third quarter 2011;
- cash flow provided by operating activities of $924 million, as compared with $556 million for third quarter 2011;
- ending cash balance of $1.6 billion, as compared with $1.5 billion at December 31, 2011;
- received $1.2 billion in proceeds from divestments of non-core assets;
- exercised option to increase credit facility from $3.0 billion to $4.0 billion, enhancing our liquidity position;
- capital spending, on a cash basis, of $785 million as compared with $607 million for third quarter of 2011; and
- ratio of debt-to-book capital of 34% as compared with 38% at December 31, 2011.

Key highlights for the third quarter of 2012 included:

- record quarterly production from continuing operations of 242 MBoe/d, up 11% year over year;
- horizontal net production within the DJ Basin increased to 31 MBoe/d, up 29% from last quarter and more than double from the third quarter of 2011;
- Marcellus production grew to 102 MMcfe/d quarterly average, an increase of 37% over last quarter;
- initiated production from the wet gas area of the Marcellus Shale that indicates our acreage is within the “super rich” area of the play;
- entered into new positions offshore Falkland Islands and Sierra Leone; and
- secured contract with new-build drillship capable of both reaching deep oil targets in the Eastern Mediterranean and supporting global drilling program.

Non-Core Divestiture Program

Our non-core divestiture program is designed to generate organizational and operational efficiencies as well as cash for use in our capital investment program. Divestitures of non-core properties allow us to allocate capital and employee resources to high-value and high-growth areas. Further, proceeds from divestitures will provide additional flexibility in the implementation of our international exploration and development programs and the acceleration of horizontal drilling activities in the DJ Basin and Marcellus Shale. During the third quarter of 2012, divestitures generated net proceeds of approximately $1.2 billion.

On August 13, 2012, we sold our 30% non-operated working interests in the Dumbarton and Lochranza fields, located in the UK sector of the North Sea, for $117 million, which included final closing adjustments from the January 1, 2012 effective date.

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During the third quarter of 2012, we closed on three sales of onshore US properties for total proceeds of $1.0 billion. The properties included our interests in about 1,400 producing wells on approximately 109,000 net acres. As of the effective date, April 1, 2012, net daily production was approximately 12,500 Boe/d.

We continue to market packages of non-core onshore US properties and our remaining North Sea properties. See Item 1. Financial Statements - Note 3. Acquisitions and Divestitures.

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. During the third quarter of 2012, we expanded our global presence by entering into joint ventures in two new areas, offshore the Falkland Islands and offshore Sierra Leone, and we spud exploratory wells at Scotia, offshore the Falkland Islands, and at Big Bend in the deepwater Gulf of Mexico.

In furtherance of our commitment to global offshore exploration and development, on September 27, 2012, we announced that we have entered into a 36-month drilling services contract with a subsidiary of Atwood Oceanics, Inc. Drilling services will be provided by a new-build drillship, the Atwood Advantage. The Atwood Advantage is currently under construction by Daewoo Shipbuilding & Marine Engineering Co., Ltd. in South Korea, and we anticipate that it will arrive at our first drilling location in the fourth quarter of 2013. The drillship will be equipped with enhanced offline capabilities, such as dual blowout preventer stacks that allow for simultaneous inspection and drilling activities, and will be rated for operations in 12,000 feet water depth/40,000 feet drill depth. The increased mobility of the Atwood Advantage, as compared with other drilling rigs, will add flexibility to our global exploration program. The drillship's advanced capabilities are sufficient to reach the deep oil target in the Eastern Mediterranean, which is the first exploration prospect we expect to drill. See Liquidity and Capital Resources - Contractual Obligations, below.

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 September 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.

We devote significant capital to our exploration program; approximately 18% 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, on October 18, 2012, we announced that the Trema exploration well in the Tilapia license offshore Cameroon did not locate commercial quantities of hydrocarbons and was being plugged and abandoned. Our total cost of the Trema well is estimated at $35 million, of which $20 million was expensed in the third quarter of 2012. During the second quarter of 2012, we recorded total dry hole cost of $118 million related to the Deep Blue exploratory well (deepwater Gulf of Mexico). At Deep Blue, hydrocarbons were found in both the initial exploration well and subsequent sidetrack; however, we and our partners decided not to proceed with additional appraisal activities.

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. For example, during the third quarter of 2012, we decided not to proceed with additional appraisal activities at the AGC Profond block, offshore Senegal/Guinea-Bissau. We relinquished the acreage and recorded exploration expense of $40 million.

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Updates of our significant exploration activities are as follows:

Wyoming (Onshore US) Our DJ Basin position has provided us with opportunities to significantly expand beyond our core Wattenberg area activities. We have expanded into Wyoming and continue to acquire 3-D seismic information and appraise this 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 have 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 currently acquiring 3-D seismic over portions of the acreage, 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. During the third quarter of 2012, we continued our exploration activities with the spudding of the Big Bend exploration well (Mississipi Canyon Block 698-1), which is targeting a crude oil play, and are evaluating other potential prospects for drilling activities. We also participated in the Central Gulf of Mexico Lease Sale 216/222 and have been awarded six new 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. We continue our appraisal program for our Diega and Carla discoveries and plan to spud an appraisal well during the fourth quarter of 2012.

In September 2012, the Government of Sierra Leone awarded us participation in two offshore exploration blocks, SL 8A-10 and SL 8B-10, covering almost 1.4 million gross acres. Under the terms of the award, Chevron (SL) Ltd. will be the operator and we will have a non-operated 30% working interest. We plan to begin acquiring 2-D seismic information over portions of the acreage in 2013. See Item 1A. Risk Factors - Our entry into new joint ventures offshore Sierra Leone and offshore the Falkland Islands will subject us to additional risks associated with exploration and development activities in those regions.

The first appraisal period for the non-operated AGC Profond block, offshore Senegal/Guinea-Bissau, expired in September 2012. We elected not to participate in the second appraisal period. As a result, undeveloped leasehold cost of $40 million was charged to exploration expense.

Eastern Mediterranean We continue an active exploration program targeting both natural gas and crude oil resources. In January 2012, we returned to the Leviathan-1 well and began drilling toward two deeper intervals in order to evaluate them 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. As mentioned above, we have entered into a contract for drilling services to be provided by the Atwood Advantage drillship, which will be rated for operations in 12,000 feet water depth/40,000 feet drill depth with the capabilities necessary to reach the target objective, and plan to begin drilling an exploratory well in late 2013.

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

In 2011 we announced a significant natural gas discovery at the A-1 well on Block 12, offshore Cyprus. We submitted an appraisal plan to the Cyprus government during July 2012 and are reviewing locations for appraisal drilling activities. See Major Development Projects Update - Block 12, below.

Offshore Nicaragua We continue to evaluate our undeveloped acreage and currently plan to spud our first exploration well, targeting an oil play, in the second half of 2013.

Offshore Falkland Islands In August 2012, we entered into this new geographical area with an agreement to farm-in an interest in license areas offshore the Falkland Islands. The Scotia exploration well, which is targeting a potential crude oil play, was spud at the end of September 2012. See Entry into Falkland Islands Joint Venture and Item 1A. Risk Factors - Our entry into new joint ventures offshore Sierra Leone and offshore the Falkland Islands will subject us to additional risks associated with exploration and development activities in those regions, below.

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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 third 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 over 200 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 46 horizontal wells during the third quarter of 2012.

We continue to refine our Wattenberg development strategy to increase our access to additional resources. We continue to evaluate 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.

Northern Colorado (Onshore US) We continue to expand our horizontal Niobrara development activities into Northern Colorado, where recent 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 200 horizontal wells discussed above, in Northern Colorado, moving to full phase development by the end of the year. We completed 11 horizontal wells during the third quarter of 2012.

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 started drilling in the wet gas areas. We assumed operatorship in the wet gas areas earlier 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 have drilled 15 wet gas wells thus far in 2012 and wet gas production began in August 2012. We recently added two additional drilling rigs and plan to drill a total of 31 wells in the wet gas area this 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, 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.

Gunflint (Deepwater Gulf of Mexico) In July 2012, we reached target depth on our Gunflint appraisal well, a follow up to our significant 2008 Gunflint crude oil discovery, and are currently evaluating the drilling results. We are also evaluating additional appraisal locations and plan to drill our second appraisal well in late 2012 or early 2013. Front-end conceptual studies have been completed, and we are working toward sanctioning of a scalable development project.

Alen (Blocks O and I, 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 for storage and sale. 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 O and I, 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 exploratory 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. The platform and jacket fabrications are complete and in transit to location. Tamar remains on schedule for commissioning in the fourth quarter of 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, realization of the full economic value of the resources 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 appraising the discovery and evaluating our commercialization options, including LNG; however, we have not yet sanctioned a development project.

Entry Into Falkland Islands Joint Venture

In August 2012, we entered into an agreement with Falkland Oil and Gas Limited (FOGL) to acquire an interest in FOGL's extensive license areas, consisting of approximately 10 million acres located South and East of the Falkland Islands. The Falkland Islands are located in the South Atlantic Ocean approximately 400 miles from the South American mainland. The agreement was approved by the Falkland Islands Government in October 2012.

Under the agreement we have farmed-in to the Northern and Southern Area Licenses for a 35% working interest. FOGL will continue as operator until we assume operatorship of the Northern Area License in early 2013 and the Southern Area License no later than early 2014.

Our financial contribution includes 60% of the costs of two commitment wells and a $25 million cash contribution to be paid in January 2013. We may also elect to participate with a 45% working interest in a discretionary exploration well. We expect to invest approximately $180 to $230 million over the next three years.

See Item 1A. Risk Factors - Our entry into new joint ventures offshore Sierra Leone and offshore the Falkland Islands will subject us to additional risks associated with exploration and development activities in those regions.

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.

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Tamar Through the date of this filing, we and our Tamar partners have entered into Gas Sale and Purchase Agreements (GSPAs) with the Israel Electric Corporation Limited (IEC) and seven 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 were 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 were also required to provide each of our remaining purchasers the right 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 1.7 Tcf of natural gas to seven 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. The amendment to the IEC GSPA is attached as Exhibit 10.1 to this Quarterly Report on Form 10-Q.

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 are currently conducting abandonment activities on the Leviathan-2 well.

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 the outcome of 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 and oral arguments in the case have been presented and the parties are awaiting the decision of the Court.

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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 from continuing operations were 11% higher for the third quarter of 2012 as compared with the third quarter of 2011, and our mix of sales volumes was 44% global liquids, 26% international natural gas, and 30% US natural gas. Onshore US sales volume increases were due to continued acceleration of our horizontal drilling programs in Wattenberg and the Marcellus Shale and were offset by the impact of our recent sales of non-core properties. In the deepwater Gulf of Mexico, new production from Galapagos and South Raton was offset by a temporary negative volume impact of nearly seven MBoe/d as a result of shut-ins due to Hurricane Isaac. Our efforts to restore production following the storm were delayed due to flooding at third party onshore facilities and minor equipment repairs. Offshore Equatorial Guinea, production continues from the new Aseng development. 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 third quarter of 2012 increased 3% as compared with the third quarter of 2011. US natural gas prices remain weak; US average realized natural gas prices for the third quarter of 2012 decreased 33% as compared with the third quarter of 2011.

Prices continue to be impacted by the 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 is likely to continue. See Potential for Future Asset Impairments below.

We have hedged approximately 42% of our expected global crude oil production and 42% 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 the remainder of 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;
- 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 both the wet gas and dry gas areas of the Marcellus Shale;
- divestments of non-core operating assets;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Rocky Mountain 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 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 production rates from the Noa and Pinnacles wells, offshore Israel;
- variations in West Africa sales volumes due to potential FPSO downtime and timing of liftings;
- 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;
- third party facilities reliability 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

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- 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 18% of total capital.

We expect that the remainder of the 2012 capital investment program will be funded from cash flows from operations and cash on hand, including the proceeds from our recent divestments 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 Liquidity and Capital Resources - Contractual Obligations below);
- property acquisitions and divestitures;
- increase in exploration activities in new venture areas, including offshore Sierra Leone and the Falkland Islands;
- 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, which has resulted in significant derivatives regulations and disclosure requirements, on our business practices. See Impact of Dodd-Frank Act, below.

Potential for Asset Impairments

We recorded asset impairment charges of $73 million during the first nine months of 2012. 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 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

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- 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. In September 2012, the Committee issued its final recommendations. In its report the Committee stated that permitting export of natural gas does not prevent, but rather promotes the ensuring of the needs of the domestic market and works to encourage development of natural gas based domestic industry. The recommendations included, among others, the following points:

- as a rule, all reservoirs should be charged with supplying a certain percentage of natural gas to the local economy, with minimum requirements based on reservoir size (minimum of 25%-50%). The minimum supply obligations will not apply for reservoirs under a certain size (25 billion cubic meters, or BCM) but the reservoirs will be required to be connected to the domestic market. The recommendations allow for a lease in a developed reservoir to exchange its export quota against an "obligation to supply to the domestic market" which applies to any other leaseholder which submitted a development plan so long as approval therefor is given by the Petroleum Commissioner in the Ministry of Energy and Water Resources and by the Antitrust Authority;
- a determination that the quantity of natural gas that should be guaranteed in favor of the local economy should be 450 BCM and that the quantity should be updated in five years;
- the export of natural gas should be permitted as long as the quantity from all reservoirs does not exceed 500 BCM, which amount may be reassessed;
- requiring regulatory approval for export, with export licenses eligible for periods up to 25 years;
- there should be an absolute preference for the export of natural gas from a facility in an area under Israeli control, including Israel's exclusive economic zone, although further study of various export means (such as export from a foreign area governed by bilateral agreement) and statutory feasibility is necessary; and
- steps should be taken to increase competition in the natural gas market.

We are participating in the process and monitoring the impact of the Committee's 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/or development projects uneconomic.

Impact of Dodd-Frank Act

Impact on our Commodity Hedging Program 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 credit 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. To the extent we incur increased costs or are required to post collateral in periods of rising commodity prices, there could be a corresponding decrease in amounts available for our capital investment program. See 2012 Capital Investment Program, above.

Impact on our Operations Section 1504 of the Dodd-Frank Act also required the SEC to issue rules requiring resource extraction issuers to include in an annual report information relating to any payment made by the issuer, a subsidiary of the issuer, or an entity under the control of the issuer, to a foreign government or the Federal Government for the purpose of the commercial development of oil, natural gas, or minerals. On August 22, 2012, the SEC issued final rules: Disclosure of Payments by Resource Extraction Issuers (Final Rules). As a result, beginning in 2014, we must provide information about the

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type and total amount of payments made for each project related to the commercial development of oil, natural gas, or minerals, and the type and total amount of payments made to each government. We are currently evaluating the provisions of the Final Rules to determine their impact on our business. Impacts could include, among others:

- loss of our license to operate in other countries where the laws and regulations or terms of production sharing or other contracts prohibit disclosures of certain information, resulting in a reduction in our profitability;
- decrease in our ability to compete for new sources of reserves with state-controlled national oil companies or large multi-national companies not subject to disclosures under the Final Rules; and
- reduction in profitability and cash flows and a decrease in the price of our common stock.

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 direct 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.

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, 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 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:

	2012	2011	Increase (Decrease) from Prior Year	
(millions)				
Three Months Ended September 30,				
Oil, Gas and NGL Sales	$954	$829	15	%
Income from Equity Method Investees	51	50	2	%
Other Revenues	1	—	—	%
Total	$1,006	$879	14	%
Nine Months Ended September 30,				
Oil, Gas and NGL Sales	$2,925	$2,328	26	%
Income from Equity Method Investees	137	146	(6	)%
Other Revenues	—	33	(100	)%
Total	$3,062	$2,507	22	%

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 September 30, 2012							
United States	52	440	16	141	$93.67	$2.61	$29.71
Equatorial Guinea (2)	27	251	—	70	108.90	0.27	—
Israel	—	116	—	19	—	4.43	—
China	3	—	—	3	107.61	—	—
Total Consolidated Operations	82	807	16	233	99.30	2.14	29.71
Equity Investees (3)	2		7	9	93.09	—	61.34
Total Continuing Operations	84	807	23	242	$99.18	$2.14	$39.05
Three Months Ended September 30, 2011							
United States	38	358	16	113	$91.21	$3.98	$49.57
Equatorial Guinea (2)	15	250	—	57	108.11	0.27	—
Israel	—	228	—	38	—	5.15	—
China	4	—	—	4	108.57	—	—
Total Consolidated Operations	57	836	16	212	96.82	3.18	49.57
Equity Investees (3)	2	—	5	7	107.90	—	72.70
Total Continuing Operations	59	836	21	219	$96.24	$3.18	$55.70
Nine Months Ended September 30, 2012							
United States	47	435	16	135	$96.20	$2.44	$34.87
Equatorial Guinea (2)	32	232	—	71	110.68	0.27	—
Israel	—	95	—	16	—	4.67	—
China	4	—	—	4	117.44	—	—
Total Consolidated Operations	83	762	16	226	102.90	2.06	34.87
Equity Investees (3)	2	—	6	8	104.09	—	63.93
Total Continuing Operations	85	762	22	234	$102.92	$2.06	$42.60
Nine Months Ended September 30, 2011							
United States	37	373	14	114	$95.10	$4.09	$49.19
Equatorial Guinea (2)	13	244	—	54	108.40	0.27	—
Israel	—	180	—	30	—	4.80	—
China	4	—	—	4	104.99	—	—
Total Consolidated Operations	54	797	14	202	98.98	3.11	49.19
Equity Investees (3)	2	—	5	7	109.20	—	74.70

Total Continuing Operations	56	797	19	209	$99.42	$3.11	$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.

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(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 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 September 30,				
United States	$(0.03)	$0.31	$(1.23)	$0.79
Equatorial Guinea	(6.57)	—	—	—
Total Consolidated Operations	(2.22)	0.17	(0.83)	0.34
Total Continuing Operations	(2.17)	0.17	(0.80)	0.34
Nine Months Ended September 30,				
United States	$(0.82)	$0.33	$(3.52)	$0.74
Equatorial Guinea	(6.48)	—	—	—
Total Consolidated Operations	(2.98)	0.19	(2.43)	0.34
Total Continuing Operations	(2.91)	0.19	(2.34)	0.34

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 September 30, 2011	$513	$246	$70	$829
Changes due to				
Increase (Decrease) in Sales Volumes	219	(8)	—	211
Increase (Decrease) in Sales Prices	19	(79)	(26)	(86)
Three Months Ended September 30, 2012	$751	$159	$44	$954
Nine Months Ended September 30, 2011	$1,464	$670	$194	$2,328
Changes due to				
Increase (Decrease) in Sales Volumes	788	(25)	28	791
Increase (Decrease) in Sales Prices	87	(216)	(65)	(194)
Nine Months Ended September 30, 2012	$2,339	$429	$157	$2,925

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the third quarter and first nine 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 which increased production by approximately 10 MBoe/d, net, during the third quarter of 2012;

- 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 20 MBbl/d, net in the first nine months of 2012 as compared with 2011; and
- slight increases in average realized prices;

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partially offset by:

- reduction in sales volumes due to the sales of non-core, onshore US properties during the third quarter of 2012;
- a volume reduction in the Gulf of Mexico of nearly seven MBoe/d as a result of shut-ins due to Hurricane Isaac; 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 third quarter and first nine 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;
- lower sales volumes due to the sales of non-core onshore US properties during the third quarter of 2012;
- lower sales volumes in the Wattenberg and Rocky Mountain areas of our US operations due to third-party processing facility constraints;
- 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 attributable to the acceleration of our horizontal drilling programs in the Wattenberg area; and
- new sales volumes from Marcellus Shale producing properties which we acquired September 30, 2011 and current Marcellus Shale development activities, which added 81 MMcf/d, net to our sales volumes for the first nine months of 2012.

NGL sales – Most of our US NGL production is currently from the Wattenberg area. NGL sales revenues decreased significantly during the third quarter of 2012 as compared with the third quarter of 2011 as a result of lower US NGL prices. Our average realized sales prices declined 40% during the third quarter of 2012 as compared with the third quarter of 2011 primarily due to higher supplies of NGLs resulting from increased wet gas drilling activities.

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 nine 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 first nine months of 2012 as compared with 2011 was due to lower 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Methanol Sales Volumes (Mmgal)	36	41	113	119

Methanol Sales Prices (per gallon)	$1.07	$1.08	$1.07	$1.04

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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 September 30,			
Production Expense	$158	$142	11 %
Exploration Expense	95	56	70 %
Depreciation, Depletion and Amortization	368	215	71 %
General and Administrative	93	89	4 %
Gain on Divestitures	(157)	—	— %
Other Operating (Income) Expense, Net	(1)	2	(150)%
Total	$556	$504	10 %
Nine Months Ended September 30,			
Production Expense	$492	$406	21 %
Exploration Expense	322	193	67 %
Depreciation, Depletion and Amortization	987	619	59 %
General and Administrative	286	253	13 %
Gain on Divestitures	(167)	(26)	542 %
Asset Impairments	73	137	(47)%
Other Operating (Income) Expense, Net	19	45	(58)%
Total	$2,012	$1,627	24 %

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 September 30, 2012						
Lease Operating Expense [2]	$4.82	$103	$68	$21	$6	$8
Production and Ad Valorem Taxes	1.43	31	24	—	—	7
Transportation and Gathering Expense	1.11	24	23	—	—	1
Total Production Expense	$7.36	$158	$115	$21	$6	$16
Three Months Ended September 30, 2011						
Lease Operating Expense [2]	$4.56	$89	$66	$12	$2	$9
Production and Ad Valorem Taxes	1.95	38	25	—	—	13
Transportation and Gathering Expense	0.77	15	15	—	—	—
Total Production Expense	$7.28	$142	$106	$12	$2	$22
Nine Months Ended September 30, 2012						
Lease Operating Expense [2]	$4.98	$309	$207	$64	$13	$25
Production and Ad Valorem Taxes	1.81	112	83	—	—	29
Transportation and Gathering Expense	1.14	71	68	—	—	3
Total Production Expense	$7.93	$492	$358	$64	$13	$57
Nine Months Ended September 30, 2011						
Lease Operating Expense [2]	$4.56	$251	$188	$35	$9	$19
Production and Ad Valorem Taxes	1.96	108	77	—	—	31
Transportation and Gathering Expense	0.86	47	45	—	—	2
Total Production Expense	$7.38	$406	$310	$35	$9	$52

(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 third quarter and first nine 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;
- an increase in US taxes 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 Israel lease operating expense due to the start-up of the Noa and Pinnacles wells.

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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 September 30, 2012					
Dry Hole Cost	$23	$3	$20	$—	$—
Seismic	7	7	—	—	—
Exploration Expense	58	5	43	2	8
Other	7	7	—	—	—
Total Exploration Expense	$95	$22	$63	$2	$8
Three Months Ended September 30, 2011					
Dry Hole Cost	$13	$—	$13	$—	$—
Seismic	8	5	—	—	3
Exploration Expense	32	14	1	1	16
Other	3	3	—	—	—
Total Exploration Expense	$56	$22	$14	$1	$19
Nine Months Ended September 30, 2012					
Dry Hole Cost	$141	$120	$21	$—	$—
Seismic	53	47	—	—	6
Exploration Expense	110	13	47	4	46
Other	18	17	1	—	—
Total Exploration Expense	$322	$197	$69	$4	$52
Nine Months Ended September 30, 2011					
Dry Hole Cost	$57	$20	$37	$—	$—
Seismic	47	28	1	3	15
Exploration Expense	75	26	4	1	44
Other	14	14	—	—	—
Total Exploration Expense	$193	$88	$42	$4	$59

[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.

Exploration expense for the third quarter and first nine months of 2012 included the following:

- $40 million related to the non-operated AGC Profond block offshore Senegal/Guinea-Bissau, which was written off due to our decision not to participate in the second appraisal period;
- dry hole cost of $20 million incurred through September 30, 2012, related to the Trema exploratory well (offshore Cameroon), which did not locate commercial quantities of hydrocarbons. We expect to record an additional $15 million of dry hole cost related to the Trema well in the fourth quarter of 2012;
- dry hole cost of $118 million related 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 third quarter and first nine 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
DD&A Expense (millions) [1]	$368	$215	$987	$619
Unit Rate per BOE [2]	$17.16	$11.02	$15.92	$11.22

[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 third quarter and first nine 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;
- the start up of Noa and Pinnacles (offshore Israel) which have higher DD&A rates;
- the start up of Galapagos and South Raton in the deepwater Gulf of Mexico which have higher DD&A rates; and
- the startup of the Aseng field which includes the Aseng FPSO in its depreciation base;

partially offset by:

- the impact of sales of non-core onshore US properties during the third quarter of 2012.

Changes in the unit rate per BOE for the third quarter and first nine 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, Galapagos, Noa, Pinnacles and South Raton projects, which have comparatively higher DD&A rates, and increased horizontal drilling activity.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
G&A Expense (millions)	$93	$89	$286	$253
Unit Rate per BOE [1]	$4.31	$4.56	$4.61	$4.59

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

G&A expense for the third quarter and first nine 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.

Gain on Divestitures Gain on divestitures was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Gain on Divestitures	$(157)	$—	$(167)	$(26)

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

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Asset Impairment Expense Asset impairment expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Asset Impairments	$—	$—	$73	$137

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Deepwater Gulf of Mexico Moratorium Expense	$—	$(1)	$—	$18
Electricity Generation Expense	—	—	—	26
Other, Net	(1)	3	19	1
Total	$(1)	$2	$19	$45

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

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
(Gain) Loss on Commodity Derivative Instruments	$135	$(322)	$(46)	$(179)
Interest, Net of Amount Capitalized	36	14	95	51
Other Non-Operating (Income) Expense, Net	4	(16)	2	(16)
Total	$175	$(324)	$51	$(144)

(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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions, except unit rate)				
Interest Expense	$69	$48	$207	$138
Capitalized Interest	(33)	(34)	(112)	(87)
Interest Expense, Net	$36	$14	$95	$51
Unit Rate per BOE [1]	$1.68	$0.70	$1.52	$0.93

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

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Interest expense prior to the reduction for capitalized interest increased for the third quarter and first nine 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.

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 third quarter and first nine months of 2012 as compared with 2011.

Discontinued Operations

Summarized results of discontinued operations were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Oil and Gas Sales	$54	$45	$194	$271
Less:				
Production Expense	14	11	39	43
DD&A Expense	1	10	33	62
Other Operating (Income) Expense, Net	1	1	5	5
Income Before Income Taxes	38	23	117	161
Income Tax Expense	3	73	50	139
Operating Income (Loss), Net of Tax	35	(50)	67	22
Gain on Sale, Net of Tax	22	—	22	—
Income (Loss) From Discontinued Operations	$57	$(50)	$89	$22
Key Statistics:				
Daily Production				
Crude Oil & Condensate (MBbl/d)	5	4	6	8
Natural Gas (MMcf/d)	3	4	4	6
Average Realized Price				
Crude Oil & Condensate (Per Bbl)	$106.03	$115.67	$113.11	$112.99
Natural Gas (Per Mcf)	8.37	8.41	8.31	7.90

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 capitalize on 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.

During the first nine months of 2012, our liquidity was enhanced by $1.2 billion in proceeds generated by our non-core asset divestiture program. In September 2012, we exercised the accordion feature of our Credit Facility, resulting in a $1.0 billion increase in the overall commitment.

Our current 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. Including our current $1.6 billion cash balance, we believe we are well-positioned to fund these long-term growth plans. See Available Liquidity, below.

In addition, we are currently evaluating potential development scenarios for our significant natural gas discoveries offshore the 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 recent 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 exercised our option to increase our Credit Facility's overall commitment amount by an additional $1.0 billion on September 28, 2012. See Credit Facility below.

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:

	September 30, 2012		December 31, 2011	
(millions, except percentages)				
Cash and Cash Equivalents	$1,617		$1,455	
Amount Available to be Borrowed Under Credit Facility [1]	4,000		3,000	
Total Liquidity	$5,617		$4,455	
Total Debt [2]	$4,134		$4,495	
Total Shareholders' Equity	8,008		7,265	
Ratio of Debt-to-Book Capital [3]	34	%	38	%

(1) See Credit Facility below.

(2) Total debt includes Aseng FPSO lease obligation and remaining CONSOL installment payment 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 $1.6 billion in cash and cash equivalents at September 30, 2012, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $964 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 to fund international projects, including the planned developments in West Africa and the Eastern Mediterranean.

Credit Facility We have an unsecured revolving credit facility (Credit Facility) that matures on October 14, 2016. The commitment is $4.0 billion through the maturity date of the Credit Facility. See Financing Activities – Long-Term Debt below.

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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 September 30, 2012, the fair value of our commodity derivative assets was $59 million and the fair value of our commodity derivative liabilities was $21 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.

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 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. 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 Carried Cost Obligation 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. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. Based on the September 30, 2012 NYMEX Henry Hub natural gas price curve, we forecast our CONSOL Carried Cost Obligation will remain suspended for the next 12 months.

Atwood Advantage Drillship During the third quarter of 2012, we entered into a 36-month drilling services contract with a subsidiary of Atwood Oceanics Inc. Drilling services will be provided by a new-build drillship, the Atwood Advantage, that will arrive at our first drilling location in the fourth quarter of 2013. The rate of $584,000 per day, gross, will begin upon arrival and will be allocated among joint venture partners. See Executive Overview - Exploration Program Update, above.

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Cash Flows

Cash flow information is as follows:

	Nine Months Ended September 30,	
	2012	2011
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$2,171	$1,785
Investing Activities	(1,559)	(2,383)
Financing Activities	(450)	769
Increase in Cash and Cash Equivalents	$162	$171

Operating Activities   Net cash provided by operating activities for the first nine months of 2012 increased 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 $817 million during the first nine 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 nine months of 2012. In addition, we received $1.2 billion proceeds from non-core asset divestitures during the first nine 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 nine 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 nine months of 2012, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($42 million). We used cash to make the first CONSOL installment payment ($328 million), pay dividends on our common stock ($119 million), make principal payments related to the Aseng FPSO capital lease obligation ($32 million) and repurchase shares of our common stock ($13 million).

In comparison, during the first nine months of 2011, funds were provided by net cash proceeds from borrowings under our revolving Credit Facility ($520 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 ($43 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 ($104 million) and repurchase shares of our common stock ($16 million).

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

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Investing Activities

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(millions)				
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$(38)	$826	$49	$883
Proved Property Acquisition	—	370	—	370
Exploration	95	58	316	286
Development	648	604	2,102	1,478
Corporate and Other	19	40	44	128
Total	$724	$1,898	$2,511	$3,145
Other				
Investment in Equity Method Investee	$—	$73	$35	$73
Increase in FPSO Lease Obligation	—	5	—	56

2012   Unproved property acquisition costs for the first nine months of 2012 included downward purchase price adjustments related to the Marcellus Shale acquisition, offset by bonuses paid on lease blocks acquired as a result of the June 2012 deepwater Gulf of Mexico lease sale, entry into a license offshore Sierra Leone (West Africa) and 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 nine months of 2011 included the Marcellus Shale acquisition, the AGC Profond Block offshore Senegal/Guinea-Bissau, and other onshore US lease acquisitions. Proved property acquisition costs related to the Marcellus Shale acquisition. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

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 short-term borrowing arrangements during the first nine months of 2012, other than draw downs and repayments under our Credit Facility for working capital purposes in the normal course of business.

The Credit Facility, after giving effect to the increase in the overall commitment as of September 28, 2012, (i) provides for an initial commitment of $4.0 billion, (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 September 30, 2012, there were no borrowings outstanding under the Credit Facility, leaving $4.0 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 $3.8 billion at September 30, 2012. The weighted average interest rate on fixed-rate debt was 5.89%, with maturities ranging from 2012 to 2097. Approximately 14% of our fixed rate debt will mature within the next five years.

Dividends   We paid total cash dividends of 66 cents per share of our common stock during the first nine months of 2012 and 58 cents per share during the first nine 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.

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Exercise of Stock Options   We received cash proceeds from the exercise of stock options of $28 million during the first nine months of 2012 and $32 million during the first nine 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 132,958 shares with a value of $13 million during the first nine months of 2012 and 181,234 shares with a value of $16 million during the first nine 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 September 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 $38 million. Based on the September 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 $20 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 $5 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 September 30, 2012, we had approximately $3.8 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 5.89%. 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 September 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 September 30, 2012, our cash and cash equivalents totaled approximately $1.6 billion, approximately 62% 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 September 30, 2012 would result in a change in annual interest income of approximately $2 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 gains were $2 million for the third quarter of 2012 and a loss of $4 million for the nine months ended September 30, 2012 compared to losses of $4 million for the third quarter of 2011 and $5 million for the nine months ended September 30, 2011. The (gains) 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 Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 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 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. In August 2012, we entered into an Administrative Order on Consent with COGCC resolving both NOAVs. In lieu of a fine payment, we agreed to institute a third

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party hydrogen sulfide awareness program with a total budget of up to $50,000 and arrange for the program to be completed by August 2013.

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 Reports on Form 10-Q for the quarters ended March 31, 2012 or June 30, 2012 or Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2011, other than the following:

Our entry into new joint ventures offshore Sierra Leone and offshore the Falkland Islands will subject us to additional risks associated with exploration and development activities in those regions.

In August 2012, we entered into an agreement with Falkland Oil and Gas Limited (FOGL) to acquire an interest in FOGL's license areas located offshore South and East of the Falkland Islands.

In September 2012, we acquired non-operated working interests in two exploration blocks offshore Sierra Leone.

These arrangements represent entry into new geographical areas in which we have no prior experience. Our activities will be subject to many risks including, among others:

- exploration activities in frontier areas may not result in commercially productive quantities of crude oil and natural gas reserves;
- there have been numerous acts of piracy, kidnapping, civil strife, regional conflict, cross-border violence, and war, as well as violence associated with corruption, drug trafficking and regime changes in the countries of West Africa which could disrupt our operations;
- the remote location of the Falkland Islands makes it more difficult and time-consuming to transport personnel, equipment and supplies; and
- harsh weather and rough seas offshore the Falkland Islands could limit certain exploration activities, such as seismic activities, during certain periods.

In addition, although the Falkland Islands are a United Kingdom Overseas Territory by choice, the government of Argentina has claimed sovereignty. Actual or perceived threats from Argentina or incursion by Argentina into the Falkland Islands territorial waters could result in disruptions to our planned activities. This risk could be intensified if commercial quantities of oil or natural gas are discovered.

We may not be able to compensate for or fully mitigate these risks.

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)
7/1/2012 - 7/31/2012	209	$86.50	—	—
8/1/2012 - 8/31/2012	91	89.03	—	—
9/1/2012 - 9/30/2012	174	91.92	—	—
Total	474	$88.98	—	—

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

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

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	October 25, 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 as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 and incorporated herein by reference).
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).
10.1	Amendment No. 1 dated July 22, 2012 to the Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd, and Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser), filed herewith.
10.2	Commitment Increase Agreement (Existing Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Date of Event: September 28, 2012), filed October 2, 2012 and incorporated herein by reference).
10.3	Commitment Increase Agreement (New Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K (Date of Event: September 28, 2012), filed October 2, 2012 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