DYNEX CAPITAL INC
Form 10-Q
August 10, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-Q
x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2015
or
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission File Number: 1-9819
DYNEX CAPITAL, INC.
(Exact name of registrant as specified in its charter)

Virginia	52-1549373
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4991 Lake Brook Drive, Suite 100, Glen Allen, Virginia	23060-9245
(Address of principal executive offices)	(Zip Code)

(804) 217-5800
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No 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 x 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	o	Accelerated filer	x
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o

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

On August 4, 2015, the registrant had 53,476,309 shares outstanding of common stock, $0.01 par value, which is the registrant's only class of common stock.

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
CONSOLIDATED BALANCE SHEETS
($ in thousands except share data)

	June 30, 2015	December 31, 2014
ASSETS	(unaudited)	
Mortgage-backed securities (including pledged of $3,797,011 and $3,265,979, respectively)	$3,852,883	$3,516,239
Mortgage loans held for investment, net	29,858	39,700
Investment in limited partnership	10,733	4,000
Cash and cash equivalents	56,463	43,944
Restricted cash	57,880	42,263
Derivative assets	20,804	5,727
Receivable for securities sold	96,168	—
Principal receivable on investments	10,584	7,420
Accrued interest receivable	21,315	21,157
Other assets, net	12,354	7,861
Total assets	$4,169,042	$3,688,311
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities:		
Repurchase agreements	$3,402,964	$3,013,110
FHLB advances	108,076	—
Payable for unsettled mortgage-backed securities	4,014	—
Non-recourse collateralized financing	8,788	10,786
Derivative liabilities	48,240	35,898
Accrued interest payable	2,067	1,947
Accrued dividends payable	14,878	15,622
Other liabilities	4,762	3,646
Total liabilities	3,593,789	3,081,009
Shareholders' equity:		
Preferred stock, par value $.01 per share, 8.5% Series A Cumulative Redeemable; 8,000,000 shares authorized; 2,300,000 shares issued and outstanding ($57,500 aggregate liquidation preference)	55,407	55,407
Preferred stock, par value $.01 per share, 7.625% Series B Cumulative Redeemable; 7,000,000 shares authorized; 2,250,000 shares issued and outstanding ($56,250 aggregate liquidation preference)	54,251	54,251
Common stock, par value $.01 per share, 200,000,000 shares authorized; 54,084,611 and 54,739,111 shares issued and outstanding, respectively	541	547
Additional paid-in capital	758,230	763,935
Accumulated other comprehensive income	4,691	21,316
Accumulated deficit	(297,867)	(288,154)
Total shareholders' equity	575,253	607,302
Total liabilities and shareholders' equity	$4,169,042	$3,688,311

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See notes to the unaudited consolidated financial statements.

DYNEX CAPITAL, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(UNAUDITED)
(amounts in thousands except per share data)

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Interest income:				
Mortgage-backed securities	$24,196	$26,995	$47,923	$53,897
Mortgage loans held for investment, net	331	723	703	1,462
	24,527	27,718	48,626	55,359
Interest expense:				
Repurchase agreements and FHLB advances	5,506	6,548	10,852	14,159
Non-recourse collateralized financing	36	24	61	46
	5,542	6,572	10,913	14,205
Net interest income	18,985	21,146	37,713	41,154
Gain (loss) on derivative instruments, net	17,090	(23,074)	(8,233)	(36,496)
Loss on sale of investments, net	(1,491)	(477)	(183)	(3,784)
Fair value adjustments, net	20	88	59	119
Equity in income of limited partnership	711	—	733	—
Other (expense) income, net	(99)	137	(88)	212
General and administrative expenses:				
Compensation and benefits	(2,351)	(2,329)	(4,467)	(4,881)
Other general and administrative	(2,403)	(1,490)	(4,544)	(3,057)
Net income (loss)	30,462	(5,999)	20,990	(6,733)
Preferred stock dividends	(2,294)	(2,294)	(4,588)	(4,588)
Net income (loss) to common shareholders	$28,168	$(8,293)	$16,402	$(11,321)
Other comprehensive income:				
Change in unrealized (loss) gain on available-for-sale investments	$(42,027)	$33,114	$(18,722)	$57,080
Reclassification adjustment for loss on sale of investments, net	1,491	477	183	3,784
Reclassification adjustment for de-designated cash flow hedges	857	1,608	1,914	3,896
Total other comprehensive (loss) income	(39,679)	35,199	(16,625)	64,760
Comprehensive (loss) income to common shareholders	$(11,511)	$26,906	$(223)	$53,439
Weighted average common shares-basic and diluted	54,574	54,711	54,687	54,669
Net income (loss) per common share-basic and diluted	$0.52	$(0.15)	$0.30	$(0.21)

See notes to the unaudited consolidated financial statements.

DYNEX CAPITAL, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(UNAUDITED)
($ in thousands)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Accumulated Deficit	Total
Balance as of December 31, 2014	$109,658	$547	$763,935	$21,316	$(288,154)	$607,302
Stock issuance	—	—	78	—	—	78
Granting and vesting of restricted stock	—	3	1,472	—	—	1,475
Amortization of stock issuance costs	—	—	(19)	—	—	(19)
Common stock repurchased	—	(8)	(6,680)	—	—	(6,688)
Adjustments for tax withholding on share-based compensation	—	(1)	(556)	—	—	(557)
Net income	—	—	—	—	20,990	20,990
Dividends on preferred stock	—	—	—	—	(4,588)	(4,588)
Dividends on common stock	—	—	—	—	(26,115)	(26,115)
Other comprehensive loss	—	—	—	(16,625)	—	(16,625)
Balance as of June 30, 2015	$109,658	$541	$758,230	$4,691	$(297,867)	$575,253

See notes to the unaudited consolidated financial statements.

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DYNEX CAPITAL, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)
($ in thousands)

	Six Months Ended June 30, 2015	2014
Operating activities:		
Net income (loss)	$20,990	$(6,733)
Adjustments to reconcile net income to cash provided by operating activities:		
Increase in accrued interest receivable	(158)	(774)
Increase (decrease) in accrued interest payable	120	(778)
Loss on derivative instruments, net	8,233	36,496
Loss on sale of investments, net	183	3,784
Fair value adjustments, net	(59)	(119)
Amortization of investment premiums, net	74,737	66,650
Other amortization and depreciation, net	2,847	5,055
Stock-based compensation expense	1,475	1,355
Other operating activities	18	598
Net cash and cash equivalents provided by operating activities	108,386	105,534
Investing activities:		
Purchase of investments	(1,000,070)	(298,699)
Principal payments received on investments	236,598	253,263
Proceeds from sales of investments	233,238	95,932
Principal payments received on mortgage loans held for investment, net	9,825	2,889
Payment to acquire interest in limited partnership	(6,000)	—
Net payments on derivatives not designated as hedges	(10,968)	(5,951)
Other investing activities	(135)	(5)
Net cash and cash equivalents (used in) provided by investing activities	(537,512)	47,429
Financing activities:		
Borrowings under (repayments of) repurchase agreements and FHLB advances, net	497,930	(133,912)
Principal payments on non-recourse collateralized financing	(2,035)	(858)
Increase in restricted cash	(15,617)	(17,362)
Proceeds from issuance of common stock, net of issuance costs	59	107
Cash paid for repurchases of common stock	(6,688)	—
Payments related to tax withholding for share-based compensation	(557)	(505)
Dividends paid	(31,447)	(32,926)
Net cash and cash equivalents provided by (used in) financing activities	441,645	(185,456)
Net increase (decrease) in cash and cash equivalents	12,519	(32,493)
Cash and cash equivalents at beginning of period	43,944	69,330
Cash and cash equivalents at end of period	$56,463	$36,837
Supplemental Disclosure of Cash Activity:		
Cash paid for interest	$8,842	$10,861

See notes to the unaudited consolidated financial statements.

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

NOTE 1 – ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Dynex Capital, Inc., ("Company") was incorporated in the Commonwealth of Virginia on December 18, 1987 and commenced operations in February 1988. The Company primarily earns income from investing on a leveraged basis in mortgage-backed securities ("MBS") that are issued or guaranteed by the U.S. Government or U.S. Government sponsored agencies ("Agency MBS") and MBS issued by others ("non-Agency MBS").

Basis of Presentation

The accompanying unaudited consolidated financial statements of Dynex Capital, Inc. and its subsidiaries (together, "Dynex" or the "Company") have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to the Quarterly Report on Form 10-Q and Article 10, Rule 10-01 of Regulation S-X promulgated by the Securities and Exchange Commission (the "SEC"). Accordingly, they do not include all of the information and notes required by GAAP for complete financial statements. In the opinion of management, all significant adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of the consolidated financial statements have been included. Operating results for the three and six months ended June 30, 2015 are not necessarily indicative of the results that may be expected for any other interim periods or for the entire year ending December 31, 2015. The unaudited consolidated financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 filed with the SEC.

Consolidation

The consolidated financial statements include the accounts of the Company and the accounts of its majority owned subsidiaries and variable interest entities ("VIE") for which it is the primary beneficiary. As a primary beneficiary, the Company has both the power to direct the activities that most significantly impact the economic performance of the VIE and a right to receive benefits or absorb losses of the entity that could be potentially significant to the VIE. The Company is required to reconsider its evaluation of whether to consolidate a VIE each reporting period, based upon changes in the facts and circumstances pertaining to the VIE. All intercompany accounts and transactions have been eliminated in consolidation.

The Company consolidates certain trusts through which it has securitized mortgage loans as a result of not meeting the sale criteria under GAAP at the time the financial assets were transferred to the trust. Additional information regarding the accounting policy for the Company's securitized mortgage loans is provided below under "Mortgage Loans Held for Investment, Net".

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements as well as the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates. The most significant estimates used by management include, but are not limited to, fair value measurements of its investments, other-than-temporary impairments, contingencies, and amortization of premiums and discounts. These items are discussed further below within this note to the consolidated financial statements.

Income Taxes

The Company has elected to be taxed as a real estate investment trust ("REIT") under the Internal Revenue Code of 1986 and the corresponding provisions of state law. To qualify as a REIT, the Company must meet certain tests including investing in primarily real estate-related assets and the required distribution of at least 90% of its annual REIT taxable income to stockholders after consideration of its net operating loss carryforward ("NOL") and not including taxable income retained in its taxable subsidiaries. As a REIT, the Company generally will not be subject to federal income tax on the amount of its income or gain that is distributed as dividends to shareholders.

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

The Company assesses its tax positions for all open tax years and determines whether the Company has any material unrecognized liabilities in accordance with Accounting Standards Codification ("ASC") Topic 740. The Company records these liabilities, if any, to the extent they are deemed more likely than not to have been incurred.

Net Income (Loss) Per Common Share

The Company did not have any potentially dilutive securities outstanding during the three or six months ended June 30, 2015 or June 30, 2014.

Holders of unvested shares of the Company's issued and outstanding restricted common stock are eligible to receive non-forfeitable dividends. As such, these unvested shares are considered participating securities as per ASC Topic 260-10 and therefore are included in the computation of basic net income (loss) per share using the two-class method. Upon vesting, restrictions on transfer expire on each share of restricted stock, and each such share of restricted stock is converted to one equal share of common stock.

Because the Company's 8.50% Series A Cumulative Redeemable Preferred Stock (the “Series A Preferred Stock”) and 7.625% Series B Cumulative Redeemable Preferred Stock (the “Series B Preferred Stock”) are redeemable at the Company's option for cash only and may convert into shares of common stock only upon a change of control of the Company, the effect of those shares is excluded from the calculation of diluted net income (loss) per common share.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash consists of cash the Company has pledged to cover initial and variation margin with its counterparties.

Mortgage-Backed Securities

The Company designates its investments in MBS as available-for-sale ("AFS"). All of the Company’s MBS are recorded at fair value on the consolidated balance sheet. Changes in unrealized gain (loss) on the Company's MBS are reported in other comprehensive income ("OCI") until each security is collected, disposed of, or determined to be other than temporarily impaired. Although the Company generally intends to hold its AFS securities until maturity, it may sell any of these securities as part of the overall management of its business. Upon the sale of an AFS security, any unrealized gain or loss is reclassified out of accumulated other comprehensive income ("AOCI") into net income as a realized "gain (loss) on sale of investments, net" using the specific identification method.

The Company’s MBS pledged as collateral against repurchase agreements and derivative instruments are included in MBS on the consolidated balance sheets with the fair value of the MBS pledged disclosed parenthetically.

Interest Income, Premium Amortization, and Discount Accretion. Interest income on MBS is accrued based on the outstanding principal balance (or notional balance in the case of interest-only, or "IO", securities) and their contractual terms. Premiums and discounts on Agency MBS as well as any non-Agency MBS rated 'AA' and higher at the time of purchase are amortized into interest income over the expected life of such securities using the effective yield method and adjustments to premium amortization are made for actual cash payments as well as changes in projected future cash payments. The Company's projections of future cash payments are based on input and analysis received from external sources and internal models, and includes assumptions about the amount and timing of credit losses, loan prepayment rates, fluctuations in interest rates, and other factors. On at least a quarterly basis, the Company reviews and makes any necessary adjustments to its cash flow projections and updates the yield recognized on these assets.

The Company holds certain non-Agency MBS that had credit ratings of less than 'AA' at the time of purchase or were not rated by any of the nationally recognized credit rating agencies. A portion of these non-Agency MBS were purchased at discounts to their par value, which management does not believe to be substantial. The discount is accreted into income over the security's expected life, which reflects management's estimate of the security's projected cash flows. Future changes in the timing of projected cash flows or differences arising between projected cash flows and actual cash flows received may result in a prospective change in the effective yield on those securities.

Determination of MBS Fair Value. The Company estimates the fair value of the majority of its MBS based upon prices obtained from third-party pricing services and broker quotes. The remainder of the Company's MBS are valued by discounting the estimated future cash flows derived from cash flow models that utilize information such as the security's coupon rate, estimated prepayment speeds, expected weighted average life, collateral composition, estimated future interest rates, expected losses, and credit enhancements as well as certain other relevant information. Refer to Note 7 for further discussion of MBS fair value measurements.

Other-than-Temporary Impairment. MBS is considered impaired when its fair value is less than its amortized cost. The Company evaluates all of its impaired MBS for other-than-temporary impairments ("OTTI") on at least a quarterly basis. An impairment is considered other-than-temporary if: (1) the Company intends to sell the MBS; (2) it is more likely than not that the Company will be required to sell the MBS before its fair value recovers; or (3) the Company does not expect to recover the full amortized cost basis of the MBS. If either of the first two conditions is met, the entire amount of the impairment is recognized in earnings. If the impairment is solely due to the inability to fully recover the amortized cost basis, the security is further analyzed to quantify any credit loss, which is the difference between the present value of cash flows expected to be collected on the MBS and its amortized cost. The credit loss, if any, is then recognized in earnings, while the balance of impairment related to other factors is recognized in other comprehensive income.

Following the recognition of an OTTI through earnings, a new cost basis is established for the security. Any subsequent recoveries in fair value may be accreted back into the amortized cost basis of the MBS on a prospective basis through interest income. Please see Note 2 for additional information related to the Company's evaluation for OTTI.

Mortgage Loans Held for Investment, Net

The Company originated or purchased mortgage loans from 1992 through 1998, and these mortgage loans are reported at amortized cost. A portion of these loans is pledged as collateral to support the repayment of one remaining class of a securitization financing bond issued by the Company in 2002. The associated securitization financing bond is treated as debt of the Company and is presented as "non-recourse collateralized financing" on the consolidated balance sheet. Securitized mortgage loans can only be sold subject to the lien of the respective securitization financing indenture. An allowance has been established for currently existing and probable losses on the Company's mortgage loans held for investment.

Investment in Limited Partnership

The Company is a limited partner with a less than 50% interest in a limited partnership for which it does not have substantive participating or kick-out rights that overcome the general partner's presumption of control. The Company accounts for its investment in this limited partnership using the equity method of accounting, which requires initially recording an investment in the equity of an investee at cost and subsequently adjusting the carrying amount of the investment to recognize the investor's share of the earnings or losses, capital contributions and distributions, and other changes in equity.

Repurchase Agreements

Repurchase agreements are accounted for as secured borrowings under which the Company pledges its securities as collateral to secure a loan, which is equal in value to a specified percentage of the estimated fair value of the pledged collateral. The Company retains beneficial ownership of the pledged collateral. At the maturity of a repurchase agreement, the Company is required to repay the loan and concurrently receives back its pledged collateral from the lender or, with the consent of the lender, the Company may renew the agreement at the then prevailing financing rate. A repurchase agreement lender may require the Company to pledge additional collateral in the event of a decline in the fair value of the collateral pledged. Repurchase agreement financing is recourse to the Company and the assets pledged. Most of the Company's repurchase agreements are based on the September 1996 version of the Bond Market Association Master Repurchase Agreement, which generally provides that the lender, as buyer, is responsible for obtaining collateral valuations from a generally recognized source agreed to by both the Company and the lender, or, in an instance when such source is not available, the value determination is made by the lender.

Derivative Instruments

The Company's derivative instruments, which currently include interest rate swaps and Eurodollar futures, are accounted for at fair value and recognized accordingly as either derivative assets or derivative liabilities on the Company's consolidated balance sheet. All periodic interest costs and changes in fair value, including gains and losses recognized upon termination, associated with derivative instruments are recorded in "gain (loss) on derivative instruments, net" on the Company's consolidated statement of comprehensive income. Please refer to Note 5 for additional information regarding the Company's accounting for its derivative instruments.

Although MBS have characteristics that meet the definition of a derivative instrument, ASC Topic 815 specifically excludes these instruments from its scope because they are accounted for as debt securities under ASC Topic 320.

Share-Based Compensation

Pursuant to the Company’s 2009 Stock and Incentive Plan ("SIP"), the Company may grant share-based compensation to eligible employees, directors or consultants or advisers to the Company, including stock awards, stock options, stock appreciation rights, dividend equivalent rights, performance shares, and restricted stock units. The Company's restricted stock currently issued and outstanding under this plan may be settled only in shares of its common stock, and therefore are treated as equity awards with their fair value measured at the grant date and recognized as compensation cost over the requisite service period with a corresponding credit to shareholders' equity. The requisite service period is the period during which an employee is required to provide service in exchange for an award, which is equivalent to the vesting period specified in the terms of the time-based restricted stock award. None of the Company's restricted stock awards have performance based conditions. The Company does not currently have any share-based compensation issued or outstanding other than restricted stock.

Contingencies

In the normal course of business, there are various lawsuits, claims, and other contingencies pending against the Company. On a quarterly basis, the Company evaluates whether to establish provisions for estimated losses from those matters in accordance with ASC Topic 450, which states that a liability is recognized for a contingent loss when: (a) the underlying causal event has occurred prior to the balance sheet date; (b) it is probable that a loss has been incurred; and (c) there is a reasonable basis for estimating that loss. A liability is not recognized for a contingent loss when it is only possible or remotely possible that a loss has been incurred, however, possible contingent losses shall be disclosed. If the contingent loss (or an additional loss in excess of any accrual) is at least a reasonable possibility and material, then the Company discloses a reasonable estimate of the possible loss or range of loss, if such reasonable estimate can be made. If the Company cannot make a reasonable estimate of the possible material loss, or range of loss, then that fact is disclosed. As of June 30, 2015, the Company does not have any contingencies for which it believes a probable loss has been incurred.

Recent Accounting Pronouncements

The Company does not believe there are any recently issued accounting pronouncements which will have a material effect on the Company's financial condition or results of operations upon their effective date.

NOTE 2 – MORTGAGE-BACKED SECURITIES

The majority of the Company's MBS are pledged as collateral to cover initial and variation margins for the Company's repurchase agreements, Federal Home Loan Bank ("FHLB") advances, and derivative instruments. The following tables provide detail by type of investment for the Company’s MBS designated as AFS as of the dates indicated:

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

	June 30, 2015						
	Par	Net Premium (Discount)	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	WAC [(1)]
RMBS:							
Agency	$1,741,996	$90,244	$1,832,240	$7,703	$(16,671)	$1,823,272	3.05 %
Non-Agency	73,896	(62)	73,834	136	(88)	73,882	3.55 %
	1,815,892	90,182	1,906,074	7,839	(16,759)	1,897,154	
CMBS:							
Agency	952,322	16,331	968,653	13,749	(15,499)	966,903	3.45 %
Non-Agency	214,220	(8,384)	205,836	6,521	(422)	211,935	4.22 %
	1,166,542	7,947	1,174,489	20,270	(15,921)	1,178,838	
CMBS IO [(2)]:							
Agency	—	426,897	426,897	9,258	(494)	435,661	0.72 %
Non-Agency	—	338,247	338,247	3,888	(905)	341,230	0.61 %
	—	765,144	765,144	13,146	(1,399)	776,891	
Total AFS securities:	$2,982,434	$863,273	$3,845,707	$41,255	$(34,079)	$3,852,883	

(1) The current weighted average coupon ("WAC") is the gross interest rate of the pool of mortgages underlying the security weighted by the outstanding principal balance (or by notional balance in the case of an IO security).

(2) The notional balance for Agency CMBS IO and non-Agency CMBS IO was $11,198,955 and $9,572,727, respectively, as of June 30, 2015.

	December 31, 2014						
	Par	Net Premium (Discount)	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	WAC [(1)]
RMBS:							
Agency	$2,086,807	$113,635	$2,200,442	$8,473	$(22,215)	$2,186,700	3.09 %
Non-Agency	22,432	(17)	22,415	107	(74)	22,448	3.83 %
	2,109,239	113,618	2,222,857	8,580	(22,289)	2,209,148	
CMBS:							
Agency	301,943	18,042	319,985	15,288	(76)	335,197	5.21 %
Non-Agency	210,358	(8,520)	201,838	6,679	(479)	208,038	4.33 %
	512,301	9,522	521,823	21,967	(555)	543,235	
CMBS IO [(2)]:							
Agency	—	426,564	426,564	12,252	(79)	438,737	0.80 %
Non-Agency	—	319,280	319,280	6,069	(230)	325,119	0.72 %
	—	745,844	745,844	18,321	(309)	763,856	
Total AFS securities:	$2,621,540	$868,984	$3,490,524	$48,868	$(23,153)	$3,516,239	

(1) The current weighted average coupon ("WAC") is the gross interest rate of the pool of mortgages underlying the security weighted by the outstanding principal balance (or by notional balance in the case of an IO security).

(2) The notional balance for the Agency CMBS IO and non-Agency CMBS IO was $10,460,113 and $7,868,896, respectively, as of December 31, 2014.

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NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

The Company's sale proceeds including MBS sales pending settlement as of June 30, 2015 were $226,884 and $329,406 for three and six months ended June 30, 2015, respectively, and $36,133 and $95,932 for the three and six months ended June 30, 2014, respectively. The following table presents the gross realized gains (losses) of those sales included in "gain (loss) on sale of investments, net" on the Company's consolidated statements of comprehensive income for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
($ in thousands)	2015	2014	2015	2014
Gross realized gains on sales of MBS	$1,361	$471	$3,134	$690
Gross realized losses on sales of MBS	(2,852)	(948)	(3,317)	(4,474)
Loss on sale of investments, net	$(1,491)	$(477)	$(183)	$(3,784)

The following table presents certain information for those Agency MBS in an unrealized loss position as of the dates indicated:

	June 30, 2015			December 31, 2014		
	Fair Value	Gross Unrealized Losses	# of Securities	Fair Value	Gross Unrealized Losses	# of Securities
Continuous unrealized loss position for less than 12 months:						
Agency MBS	$1,052,413	$(17,343)	68	$322,741	$(879)	24
Non-Agency MBS	212,569	(1,349)	39	111,778	(625)	24
Continuous unrealized loss position for 12 months or longer:						
Agency MBS	$886,126	$(15,321)	73	$1,321,323	$(21,491)	113
Non-Agency MBS	1,348	(66)	5	18,037	(159)	5

Because the principal related to Agency MBS is guaranteed by the government-sponsored entities Fannie Mae and Freddie Mac which have the implicit guarantee of the U.S. government, the Company does not consider any of the unrealized losses on its Agency MBS to be credit related. Although the unrealized losses are not credit related, the Company assesses its ability and intent to hold any Agency MBS with an unrealized loss until the recovery in its value. This assessment is based on the amount of the unrealized loss and significance of the related investment as well as the Company’s current leverage and anticipated liquidity. Based on this analysis, the Company has determined that the unrealized losses on its Agency MBS as of June 30, 2015 and December 31, 2014 were temporary.

The Company also reviews any non-Agency MBS in an unrealized loss position to evaluate whether any decline in fair value represents an OTTI. The evaluation includes a review of the credit ratings of these non-Agency MBS and the seasoning of the mortgage loans collateralizing these securities as well as the estimated future cash flows which include projected losses. The Company performed this evaluation for the non-Agency MBS in an unrealized loss position and has determined that there have not been any adverse changes in the timing or amount of estimated future cash flows that necessitate a recognition of OTTI amounts as of June 30, 2015 or December 31, 2014.

NOTE 3 – REPURCHASE AGREEMENTS

The Company finances its purchases of investments primarily using repurchase agreements which bear interest at a floating rate based on a spread to London Interbank Offered Rate ("LIBOR").The Company’s repurchase agreement borrowings outstanding as of June 30, 2015 and December 31, 2014 are summarized in the table below by the fair value and type of securities pledged as collateral:

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

	June 30, 2015		
Collateral Type	Balance	Weighted Average Rate	Fair Value of Collateral Pledged
Agency RMBS	$1,786,642	0.40 %	$1,856,421
Non-Agency RMBS	57,775	1.61 %	69,906
Agency CMBS	740,454	0.36 %	807,758
Non-Agency CMBS	168,920	1.04 %	194,021
Agency CMBS IO	360,837	0.94 %	420,519
Non-Agency CMBS IO	280,125	1.06 %	332,530
Securitization financing bond	8,211	1.54 %	8,999
	$3,402,964	0.56 %	$3,690,154

	December 31, 2014		
Collateral Type	Balance	Weighted Average Rate	Fair Value of Collateral Pledged
Agency RMBS	$1,977,338	0.39 %	$2,064,704
Non-Agency RMBS	17,594	1.57 %	21,787
Agency CMBS	253,857	0.36 %	291,103
Non-Agency CMBS	114,895	1.15 %	140,216
Agency CMBS IOs	372,609	0.92 %	430,638
Non-Agency CMBS IOs	266,983	1.04 %	315,149
Securitization financing bond	9,834	1.51 %	11,000
	$3,013,110	0.55 %	$3,274,597

As of June 30, 2015, the weighted average remaining term to maturity of our repurchase agreements was 27 days. The following table provides a summary of the original term to maturity of our repurchase agreements as of June 30, 2015 and December 31, 2014:

Original Term to Maturity	June 30, 2015	December 31, 2014
Less than 30 days	$127,899	$250,635
30 to 90 days	2,437,689	617,399
91 to 180 days	388,951	904,830
181 to 364 days	335,570	1,030,569
1 year or longer	112,855	209,677
	$3,402,964	$3,013,110

As of June 30, 2015, shareholders' equity at risk did not exceed 10% for any of the Company's counterparties. The Company had $271,576 of its repurchase agreement balance as of June 30, 2015 outstanding under a term repurchase facility with Wells Fargo Bank National Association. This facility has an aggregate maximum borrowing capacity of $300,000 and is scheduled to mature on August 6, 2016, subject to early termination provisions contained in the master repurchase agreement. The facility is collateralized primarily by CMBS IO, and its weighted average borrowing rate as of June 30, 2015 was 1.04%.

As of June 30, 2015, the Company had repurchase agreement amounts outstanding with 21 of its 32 available repurchase agreement counterparties. The Company's counterparties, as set forth in the master repurchase agreement with the counterparty, require the Company to comply with various customary operating and financial covenants, including, but not limited to, minimum net worth, maximum declines in net worth in a given period, and maximum leverage requirements as well as maintaining the Company's REIT status. In addition, some of the agreements contain cross default features, whereby default under an agreement with one lender simultaneously causes default under agreements with other lenders. To the extent that the Company fails to comply with the covenants contained in these financing agreements or is otherwise found to be in default under the terms of such agreements, the counterparty has the right to accelerate amounts due under the master repurchase agreement. The Company was in compliance with all covenants as of June 30, 2015.

Please see Note 6 for the Company's disclosures related to offsetting assets and liabilities.

NOTE 4 – FHLB ADVANCES

On May 19, 2015, the Company’s wholly owned subsidiary, Mackinaw Insurance Company, LLC ("Mackinaw") was approved for membership in the FHLB of Indianapolis ("FHLBI"). As a member of the FHLBI, Mackinaw has access to a variety of products and services offered by the FHLB system, including short-term secured advances. The Company accounts for FHLB advances as short-term borrowings collateralized by Agency MBS. FHLB advances are carried at their amortized cost, which approximates their fair value due to their short-term nature. As of June 30, 2015, Mackinaw had $108,076 in outstanding advances with a borrowing rate of 0.22% and Agency MBS with a fair value of $113,991 pledged as collateral. The Company's maximum borrowing capacity with the FHLB was $575,000 as of June 30, 2015. As of June 30, 2015, the Company's FHLB advances were all due within 30 days.

As a condition to membership in the FHLBI, the Company is required to purchase and hold a certain amount of FHLBI stock, which is based, in part, upon the outstanding principal balance of FHLB advances. As of June 30, 2015, the Company had stock in the FHLBI totaling $4,864, which is included in "other assets, net" on its consolidated balance sheet. FHLBI stock is considered a non-marketable, long-term investment, is carried at cost and is subject to recoverability testing under applicable accounting standards. This stock can only be redeemed or sold at its par value and only to the FHLBI.

NOTE 5 – DERIVATIVES

The Company utilizes derivative instruments to economically hedge a portion of its exposure to market risks, primarily interest rate risk. The Company primarily uses pay-fixed interest rate swaps and Eurodollar contracts to hedge its exposure to changes in interest rates and uses receive-fixed interest rate swaps to offset a portion of its pay-fixed interest rate swaps in order to manage its overall hedge position. The objective of the Company's risk management strategy is to mitigate declines in book value resulting from fluctuations in the fair value of the Company's assets from changing interest rates and to protect some portion of the Company's earnings from rising interest rates. Please refer to Note 1 for information related to the Company's accounting policy for its derivative instruments.

The table below summarizes information about the Company’s derivative instruments treated as trading instruments on its consolidated balance sheet as of the dates indicated:

June 30, 2015

	Derivative Assets		Derivative Liabilities	
Trading Instruments	Fair Value	Notional	Fair Value	Notional
Interest rate swaps	$20,804	$1,305,000	$(4,249)	$885,000
Eurodollar futures [1]	—	—	(43,991)	14,000,000
Total	$20,804	$1,305,000	$(48,240)	$14,885,000

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NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DYNEX CAPITAL, INC.
(amounts in thousands except share and per share data)

	December 31, 2014			
	Derivative Assets		Derivative Liabilities	
Trading Instruments	Fair Value	Notional	Fair Value	Notional
Interest rate swaps	$5,727	$440,000	$(3,002)	$485,000
Eurodollar futures [1]	—	—	(32,896)	16,600,000
Total	$5,727	$440,000	$(35,898)	$17,085,000

(1) The Eurodollar futures aggregate notional amount represents the total notional of the 3-month contracts with expiration dates from 2015 to 2020. The maximum notional outstanding for any future 3-month period did not exceed $1,300,000 as of June 30, 2015 or as of December 31, 2014.

The following table summarizes the contractual maturities remaining for the Company's outstanding interest rate swap agreements as of June 30, 2015:

Remaining Maturity	Pay-Fixed Interest Rate Swaps	Pay-Fixed Weighted-Average Rate	Receive-Fixed Interest Rate Swaps	Receive-Fixed Weighted-Average Rate
37-48 months	$			

COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 1,245	$ 253	$ 821	$ (1,074)	$ 1,245

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the Nine Months Ended September 30, 2012

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation	Reclassifications & Eliminations	Consolidated
			(In millions)		
REVENUES AND OTHER:					
Oil and gas production revenues	$ 3,070	$	$ 9,484	$	$ 12,554
Equity in net income (loss) of affiliates	813	(672)	176	(317)	
Other	(1)	52	85	(3)	133
	3,882	(620)	9,745	(320)	12,687
OPERATING EXPENSES:					
Depreciation, depletion and amortization	997		4,704		5,701
Asset retirement obligation accretion	57		115		172
Lease operating expenses	708		1,470		2,178
Gathering and transportation	38		197		235
Taxes other than income	146		481		627
General and administrative	302		85	(3)	384
Merger, acquisitions & transition	23		6		29
Financing costs, net	71	42	12		125
	2,342	42	7,070	(3)	9,451
INCOME (LOSS) BEFORE INCOME TAXES	1,540	(662)	2,675	(317)	3,236
Provision (benefit) for income taxes	207	(166)	1,862		1,903
NET INCOME (LOSS)	1,333	(496)	813	(317)	1,333
Preferred stock dividends	57				57
INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 1,276	$ (496)	$ 813	$ (317)	$ 1,276
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 1,196	$ (496)	$ 813	$ (317)	$ 1,196

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the Nine Months Ended September 30, 2011

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation (In millions)	Reclassifications & Eliminations	Consolidated
REVENUES AND OTHER:					
Oil and gas production revenues	$ 3,230	$	$ 9,285	$	$ 12,515
Equity in net income (loss) of affiliates	2,687	163	17	(2,867)	
Other	23	109	(53)	(3)	76
	5,940	272	9,249	(2,870)	12,591
OPERATING EXPENSES:					
Depreciation, depletion and amortization	938		2,092		3,030
Asset retirement obligation accretion	52		62		114
Lease operating expenses	603		1,343		1,946
Gathering and transportation	37		184		221
Taxes other than income	140		523		663
General and administrative	262		68	(3)	327
Merger, acquisitions & transition	10		5		15
Financing costs, net	104	42	(23)		123
	2,146	42	4,254	(3)	6,439
INCOME (LOSS) BEFORE INCOME TAXES	3,794	230	4,995	(2,867)	6,152
Provision (benefit) for income taxes	399	50	2,308		2,757
NET INCOME (LOSS)	3,395	180	2,687	(2,867)	3,395
Preferred stock dividends	57				57
INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 3,338	$ 180	$ 2,687	$ (2,867)	$ 3,338
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 3,541	$ 180	$ 2,687	$ (2,867)	$ 3,541

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the Nine Months Ended September 30, 2012

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation	Reclassifications & Eliminations	Consolidated
			(In millions)		
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ 1,755	$ (86)	$ 4,753	$	$ 6,422
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to oil and gas property	(2,330)		(4,057)		(6,387)
Additions to gas gathering, transmission and processing facilities	(28)		(558)		(586)
Acquisition of Cordillera	(2,666)				(2,666)
Equity investment in Yara Pilbara Holdings Pty Limited			(439)		(439)
Acquisitions, other	(56)		(66)		(122)
Proceeds from sale of oil and gas properties	20		6		26
Investment in subsidiaries, net	(541)			541	
Other	(340)		(46)		(386)
NET CASH USED IN INVESTING ACTIVITIES	(5,941)		(5,160)	541	(10,560)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Commercial paper, credit facility and bank notes, net	1,792		35		1,827
Intercompany borrowings			572	(572)	
Fixed rate debt borrowings	2,991				2,991
Payments on fixed rate debt	(400)				(400)
Dividends paid	(246)				(246)
Other	40	82	(164)	31	(11)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	4,177	82	443	(541)	4,161
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(9)	(4)	36		23
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	41	5	249		295
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 32	$ 1	$ 285	$	$ 318

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the Nine Months Ended September 30, 2011

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation (In millions)	Reclassifications & Eliminations	Consolidated
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ 1,573	$ (34)	$ 5,632	$	$ 7,171
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to oil and gas property	(1,280)		(3,478)		(4,758)
Additions to gas gathering, transmission and processing facilities			(472)		(472)
Acquisitions, other	(416)		(93)		(509)
Proceeds from sales of oil and gas properties	6		196		202
Investment in subsidiaries, net	1,256			(1,256)	
Other	(65)		(24)		(89)
NET CASH USED IN INVESTING ACTIVITIES	(499)		(3,871)	(1,256)	(5,626)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Commercial paper, credit facility and bank notes, net	(928)		(12)		(940)
Intercompany borrowings		(1)	(1,248)	1,249	
Dividends paid	(230)				(230)
Other	97	35	(62)	7	77
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(1,061)	34	(1,322)	1,256	(1,093)
NET INCREASE IN CASH AND CASH EQUIVALENTS	13		439		452
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	6		128		134
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 19	$	$ 567	$	$ 586

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET

September 30, 2012

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation (In millions)	Reclassifications & Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 31	$ 1	$ 286	$	$ 318
Receivables, net of allowance	799		2,177		2,976
Inventories	73		701		774
Drilling advances	17	1	555		573
Derivative instruments	54		50		104
Prepaid assets and other	3,904		(3,605)		299
	4,878	2	164		5,044
PROPERTY AND EQUIPMENT, NET	17,720		33,444		51,164
OTHER ASSETS:					
Intercompany receivable, net	4,504		(2,361)	(2,143)	
Equity in affiliates	20,761	741	89	(21,591)	
Goodwill, net			1,114		1,114
Deferred charges and other	179	1,002	1,307	(1,000)	1,488
	$ 48,042	$ 1,745	$ 33,757	$ (24,734)	$ 58,810
LIABILITIES AND SHAREHOLDERS EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 670	$ 1	$ 2,609	$ (2,143)	$ 1,137
Current debt	899		65		964
Asset retirement obligation	434				434
Derivative instruments	20		36		56
Other current liabilities	793	12	1,994		2,799
	2,816	13	4,704	(2,143)	5,390
LONG-TERM DEBT	10,022	647	1		10,670
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:					
Income taxes	2,878	5	4,719		7,602
Asset retirement obligation	1,006		2,788		3,794
Other	606	250	784	(1,000)	640
	4,490	255	8,291	(1,000)	12,036
COMMITMENTS AND CONTINGENCIES					
SHAREHOLDERS EQUITY	30,714	830	20,761	(21,591)	30,714

$	48,042	$	1,745	$	33,757	$	(24,734)	$	58,810

APACHE CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2011

	Apache Corporation	Apache Finance Canada	All Other Subsidiaries of Apache Corporation (In millions)	Reclassifications & Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 41	$ 5	$ 249	$	$ 295
Receivables, net of allowance	773		2,306		3,079
Inventories	51		604		655
Drilling advances	11		218		229
Derivative instruments	113		191		304
Prepaid assets and other	3,859		(3,618)		241
	4,848	5	(50)		4,803
PROPERTY AND EQUIPMENT, NET	12,262		33,186		45,448
OTHER ASSETS:					
Intercompany receivable, net	3,931		(1,908)	(2,023)	
Equity in affiliates	20,214	1,372	99	(21,685)	
Goodwill, net			1,114		1,114
Deferred charges and other	158	1,002	526	(1,000)	686
	$ 41,413	$ 2,379	$ 32,967	$ (24,708)	$ 52,051
LIABILITIES AND SHAREHOLDERS EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 609	$ 1	$ 2,461	$ (2,023)	$ 1,048
Current debt	400		31		431
Asset retirement obligation	434		13		447
Derivative instruments	76		37		113
Other current liabilities	614	5	2,305		2,924
	2,133	6	4,847	(2,023)	4,963
LONG-TERM DEBT	6,137	647	1		6,785
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:					
Income taxes	2,622	5	4,570		7,197
Asset retirement obligation	936		2,504		3,440
Other	592	250	831	(1,000)	673
	4,150	255	7,905	(1,000)	11,310
COMMITMENTS AND CONTINGENCIES					
SHAREHOLDERS EQUITY	28,993	1,471	20,214	(21,685)	28,993

$ 41,413	$ 2,379	$ 32,967	$ (24,708)	$ 52,051

ITEM 2 MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops and produces natural gas, crude oil, and natural gas liquids. We currently have exploration and production interests in six countries: the U.S., Canada, Egypt, Australia, offshore the United Kingdom (U.K.) in the North Sea, and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities.

This discussion relates to Apache Corporation and its consolidated subsidiaries and should be read in conjunction with our consolidated financial statements and accompanying notes included under Part I, Item 1, Financial Statements of this Quarterly Report on Form 10-Q, as well as our consolidated financial statements, accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K for our 2011 fiscal year.

Financial Overview

Throughout 2012, Apache s results have been impacted by the significant fall in North American natural gas prices compared to the prior year. However, our overall results continue to be supported by our strategy to maintain a portfolio balanced across crude oil and natural gas in North American and international markets. Our projects balance the spectrum of geologic types and risks in a variety of geographies. This allows us to redeploy capital dollars to parts of our portfolio that offer higher investment returns while reducing capital projects better deferred in today s environment. We have invested $2.9 billion and $7.8 billion for exploration and development activities in the third quarter and first nine months of 2012, respectively, and will continue to review our capital program and spending levels in order to maintain our rate of return focus and manage our balance sheet.

Earnings totaled $161 million, or $0.41 per diluted common share, in the third quarter of 2012, compared with $983 million, or $2.50 per diluted share, in the third quarter of 2011. Earnings for the first nine months of 2012 totaled $1.3 billion, or $3.27 per diluted share. These earnings reflect the impact of non-cash after-tax write-downs of the carrying value of our Canadian proved oil and gas properties totaling $390 million, $480 million, and $539 million in the first, second, and third quarters of 2012, respectively. For additional discussion on these write-downs, refer to Results of Operations Depreciation, Depletion and Amortization in this Item 2.

Apache s adjusted earnings, which exclude certain items impacting the comparability of results, were $861 million in the third quarter of 2012, down from $1.2 billion in the prior-year quarter, and $2.9 billion for the first nine months of 2012, down from $3.5 billion in the prior-year comparative period. Adjusted earnings is not a financial measure prepared in accordance with accounting principles generally accepted in the U.S. (GAAP). For a description of adjusted earnings and a reconciliation of adjusted earnings to income attributable to common stock, the most directly comparable GAAP financial measure, please see Non-GAAP Measures in this Item 2.

Total daily production of oil, natural gas, and natural gas liquids averaged 771 thousand barrels of oil equivalent per day (Mboe/d) in the third quarter of 2012, up two percent compared with the third quarter of 2011. Increased production in the quarter was tempered by downtime resulting from Hurricane Isaac in the Gulf of Mexico and planned turnaround activities and downhole pump issues in the North Sea, which reduced third quarter production approximately 25 Mboe/d. Although production was higher than the prior-year quarter, oil and gas production revenues decreased three percent from the prior-year quarter to $4.1 billion on a 15-percent decline in natural gas realizations, partially offset by a one-percent rise in crude oil realizations.

Natural gas price realizations in North America have fallen 27 percent since the third quarter of 2011, and we believe weak natural gas prices in North America will continue to pressure gas revenues for the remainder of the year. Our natural gas production outside of North America, where third-quarter 2012 prices averaged 13 percent higher than the comparative 2011 quarter, boosted worldwide natural gas realizations. Over one-third of our natural gas is produced outside of North America, which emphasizes the benefit of having a balanced geographic base.

Third-quarter 2012 worldwide crude oil prices rose one percent from the prior-year quarter. Crude oil and liquids combined represented 51 percent of our production but provided 81 percent of our $4.1 billion of oil and gas revenues. Crude oil drove 87 percent of our combined crude and liquids production and 96 percent of the related revenues.

Operational Developments

Apache has a significant producing asset base as well as large undeveloped acreage positions that provide a platform for organic growth through sustainable lower-risk drilling opportunities, balanced by higher-risk, higher-reward exploration. With an inventory of more than 67,000 future drilling locations identified in the onshore United States alone, we are well positioned to grow through an active drilling program in the coming years as we shift our drilling and exploration focus to targeting oil and liquids-rich gas plays. We are also continuing to advance several longer-term, individually significant development projects. Notable operational developments include:

United States

For the third quarter of 2012, our Permian region s active drilling program continues to set new highs for net production, reaching 112 Mboe/d, up 18 percent from the prior-year quarter. Over 70 percent of this production was from crude oil and natural gas liquids (NGL).

The Central region also saw record production in the third quarter as we ramp up activity across our nearly two million gross acres. Production was up 55 percent relative to the prior-year quarter as we realized the benefits of our active oil and liquids-rich drilling program and a full quarter of Cordillera production. During the quarter we operated an average of 24 drilling rigs, drilling 40 wells with 100 percent success.

On October 3, 2012, Apache announced that our Gulf of Mexico (GOM) production facilities were back online following suspended operations due to Hurricane Isaac. GOM production was deferred for six weeks in August and September, impacting third-quarter volumes from our Deepwater, Shelf, and Gulf Coast Onshore regions by an estimated 13 Mboe/d for the full quarter.

North Sea

In September 2012, Apache announced that a Beryl field development well test-flowed at 8,161 barrels of oil per day (b/d) and 5.9 million cubic feet of natural gas per day (MMcf/d). The well contained 71 feet of net oil pay and began producing at the end of August. The well also encountered 245 feet of net pay in three additional zones that will be produced at a later date. A 3-D seismic survey of the Beryl field commenced in early August and, when completed, will further refine our drilling plans for these recently acquired assets. Apache has a 50-percent interest in the field.

Apache announced that the jacket for the Forties Alpha Satellite Platform was installed in September 2012, with a fully commissioned topside and bridge scheduled to be delivered during the second quarter of 2013. Once complete, the platform will provide Apache with full-fluid processing and contain 18 new production well slots that will facilitate additional drilling in the field beginning in the third quarter of 2013. With this platform, we will continue to develop the Forties field that was forecasted by the previous operator to cease production this year.

On October 3, 2012, Apache announced that North Sea production has recovered following platform maintenance activities completed during the third quarter. These planned turnarounds and continued downhole pump issues deferred nearly 12 Mboe/d during the period.

On November 1, 2012, Apache announced that the U.K. Department of Energy & Climate Change awarded 11 new North Sea licenses to Apache. The Company was also awarded an interest in another non-operated license. These awards cover 19 full or partial blocks (approximately 613,000 gross acres). Included in these blocks is all of the available acreage around our Beryl field plus two key licenses near the Forties field.

Australia

In October 2012, an Apache subsidiary announced that three major contracts with a total value of AUD$325 million net to Apache have been awarded for the development of the Julimar subsea facilities. Gas from the Julimar Development Project (JDP) will feed into the Wheatstone LNG project. Apache has a 65-percent interest in the JDP and is the operator. Apache has a 13-percent interest in the Chevron-operated Wheatstone project. The value of the contracts were within budgetary expectations and represented the final significant subsea contracts to be awarded for the JDP.

Also in October 2012, a planned three-week maintenance turnaround at the Yara Australia Pty Ltd (Yara) operated ammonia plant on the Burrup Peninsula of Western Australia was extended to nine weeks, the result of an unforeseen equipment problem. Yara expects production at the Burrup plant to resume in the second half of November 2012.

Egypt

During the quarter, the Company s operations continued unabated with an average of 26 rigs in Egypt, drilling 68 wells during the period, including 11 exploratory wells. In addition, during the quarter we experienced faster government approvals of development leases as compared to the prior year, where we experienced delays of nine months or more. Our exploration efforts made several discoveries, continuing recent successes identifying opportunities in deeper drilling horizons.

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In October 2012, the Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, announced that it is providing reinsurance for the Overseas Private Investment Corporation s (OPIC) political risk insurance policy to Apache Corporation and its subsidiaries for oil and gas sector investments in Egypt. This provision of long-term reinsurance to OPIC will allow Apache to maintain the level of insurance coverage that has been in place since 2004. MIGA is providing $150 million to OPIC for its $300 million coverage to Apache. The reinsurance will be provided for an additional 13 years against the risks of expropriation and breach of contract.

New Ventures

In September 2012, Apache announced that the Mbawa 1 offshore exploration well in Kenya encountered natural gas. The well encountered 170 feet of natural gas pay in three zones; however, no oil was encountered. Apache and its partners in the Kenya L8 Joint Venture are analyzing the well data to determine the potential for future exploration activities. Apache has a 50-percent interest in the Mbawa well and Block L8 and is the operator.

On October 18, 2012, Apache signed a production sharing contract with Staatsolie Maatschappij Suriname NV (Staatsolie) for block 53 off the northwest coast of Suriname. The contract offers Staatsolie the opportunity to purchase a stake in the development phase of up to 20 percent. Under the agreement, if a commercial find is made and brought into production, Apache will receive reimbursement for exploration phase costs. The two-phase exploration period under the contract includes an investment by Apache of approximately $230 million and drilling at least two wells.

Results of Operations

Oil and Gas Revenues

	For the Quarter Ended September 30, 2012		For the Quarter Ended September 30, 2011		For the Nine Months Ended September 30, 2012		For the Nine Months Ended September 30, 2011	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
				($ in millions)				
Total Oil Revenues:								
United States	$ 1,143	35%	$ 1,040	33%	$ 3,409	35%	$ 3,008	32%
Canada	115	4%	105	3%	361	3%	355	4%
North America	1,258	39%	1,145	36%	3,770	38%	3,363	36%
Egypt	1,021	32%	1,054	33%	3,028	31%	3,149	34%
Australia	303	9%	411	12%	947	10%	1,167	12%
North Sea	571	18%	542	17%	1,876	19%	1,535	16%
Argentina	67	2%	60	2%	203	2%	170	2%
International	1,962	61%	2,067	64%	6,054	62%	6,021	64%
Total(1)	$ 3,220	100%	$ 3,212	100%	$ 9,824	100%	$ 9,384	100%
Total Gas Revenues:								
United States	$ 288	36%	$ 399	43%	$ 837	36%	$ 1,185	43%
Canada	186	24%	256	28%	547	23%	792	29%
North America	474	60%	655	71%	1,384	59%	1,977	72%
Egypt	122	15%	159	17%	375	16%	464	17%
Australia	94	12%	50	5%	264	11%	136	5%
North Sea	44	6%	5	1%	148	7%	14	1%
Argentina	54	7%	57	6%	168	7%	147	5%
International	314	40%	271	29%	955	41%	761	28%
Total(2)	$ 788	100%	$ 926	100%	$ 2,339	100%	$ 2,738	100%
Natural Gas Liquids (NGL) Revenues:								
United States	$ 102	76%	$ 109	75%	$ 279	71%	$ 292	74%
Canada	17	13%	27	19%	58	15%	76	19%
North America	119	89%	136	94%	337	86%	368	93%
Egypt			1	1%		0%	2	1%
North Sea	9	7%			36	9%		
Argentina	5	4%	7	5%	18	5%	23	6%
International	14	11%	8	6%	54	14%	25	7%
Total	$ 133	100%	$ 144	100%	$ 391	100%	$ 393	100%
Total Oil and Gas Revenues:								

United States	$ 1,533	37%	$ 1,548	36%	$ 4,525	36%	$ 4,485	36%
Canada	318	8%	388	9%	966	8%	1,223	10%
North America	1,851	45%	1,936	45%	5,491	44%	5,708	46%
Egypt	1,143	28%	1,214	28%	3,403	27%	3,615	29%
Australia	397	9%	461	11%	1,211	10%	1,303	10%
North Sea	624	15%	547	13%	2,060	16%	1,549	12%
Argentina	126	3%	124	3%	389	3%	340	3%
International	2,290	55%	2,346	55%	7,063	56%	6,807	54%
Total	$ 4,141	100%	$ 4,282	100%	$ 12,554	100%	$ 12,515	100%

(1) Financial derivative hedging activities decreased oil revenues $22 million and $126 million for the 2012 third quarter and nine-month period, respectively, and $82 million and $301 million for the 2011 third quarter and nine-month period, respectively.

(2) Financial derivative hedging activities increased natural gas revenues $105 million and $328 million for the 2012 third quarter and nine-month period, respectively, and $65 million and $190 million for the 2011 third quarter and nine-month period, respectively.

Production

	For the Quarter Ended September 30,			For the Nine Months Ended September 30,		
	2012	**2011**	**Increase (Decrease)**	**2012**	**2011**	**Increase (Decrease)**
Oil Volume b/d:						
United States	133,001	120,353	11%	128,884	117,135	10%
Canada	15,075	13,027	16%	15,311	14,040	9%
North America	148,076	133,380	11%	144,195	131,175	10%
Egypt	97,546	103,289	(6%)	98,648	103,913	(5%)
Australia	28,191	39,400	(28%)	29,690	38,248	(22%)
North Sea	57,296	57,838	(1%)	63,058	54,097	17%
Argentina	9,885	9,461	4%	9,701	9,577	1%
International	192,918	209,988	(8%)	201,097	205,835	(2%)
Total[(1)]	340,994	343,368	(1%)	345,292	337,010	2%
Natural Gas Volume Mcf/d:						
United States	863,433	857,993	1%	841,859	865,474	(3%)
Canada	604,442	619,897	(2%)	617,530	633,031	(2%)
North America	1,467,875	1,477,890	(1%)	1,459,389	1,498,505	(3%)
Egypt	329,793	376,259	(12%)	354,856	368,898	(4%)
Australia	215,317	187,852	15%	217,053	183,470	18%
North Sea	54,478	2,497	NM	62,061	2,257	NM
Argentina	213,745	223,929	(5%)	216,399	209,206	3%
International	813,333	790,537	3%	850,369	763,831	11%
Total[(2)]	2,281,208	2,268,427	1%	2,309,758	2,262,336	2%
Natural Gas Liquids (NGL) Volume b/d:						
United States	39,076	21,919	78%	30,385	21,001	45%
Canada	6,036	6,120	(1%)	6,063	6,220	(3%)
North America	45,112	28,039	61%	36,448	27,221	34%
Egypt		(4)	NM		66	NM
North Sea	1,470	14	NM	1,797	5	NM
Argentina	3,006	3,008	0%	3,022	3,024	0%
International	4,476	3,018	48%	4,819	3,095	56%
Total	49,588	31,057	60%	41,267	30,316	36%
BOE per day[(3)]						
United States	315,982	285,271	11%	299,578	282,381	6%
Canada	121,851	122,463	0%	124,296	125,765	(1%)

North America	437,833	407,734	7%	423,874	408,146	4%
Egypt	152,512	165,995	(8%)	157,791	165,461	(5%)
Australia	64,078	70,708	(9%)	65,866	68,826	(4%)
North Sea	67,845	58,269	16%	75,198	54,478	38%
Argentina	48,515	49,790	(3%)	48,790	47,471	3%
International	332,950	344,762	(3%)	347,645	336,236	3%
Total	770,783	752,496	2%	771,519	744,382	4%

(1) Approximately 12 and 14 percent of worldwide oil production was subject to financial derivative hedges for the third quarter and nine-month period of 2012, respectively, and 28 and 29 percent for the comparative 2011 third quarter and nine-month periods, respectively.

(2) Approximately 13 percent of worldwide natural gas production was subject to financial derivative hedges for the third quarter and nine-month period of 2012, and 15 and 16 percent for the comparative 2011 third quarter and nine-month periods, respectively.

(3) The table shows production on a barrel of oil equivalent basis (boe) in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the price ratio between the two products.

NM Not meaningful

Pricing

	For the Quarter Ended September 30,			For the Nine Months Ended September 30,		
	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
Average Oil Price - Per barrel:						
United States	$ 93.38	$ 93.86	(1%)	$ 96.53	$ 94.05	3%
Canada	82.92	88.34	(6%)	85.96	92.77	(7%)
North America	92.32	93.32	(1%)	95.41	93.91	2%
Egypt	113.72	110.96	2%	112.02	111.02	1%
Australia	116.79	113.40	3%	116.39	111.78	4%
North Sea	108.44	101.85	6%	108.60	103.90	5%
Argentina	73.44	69.27	6%	76.36	65.08	17%
International	110.54	107.03	3%	109.87	107.15	3%
Total(1)	102.62	101.71	1%	103.83	102.00	2%
Average Natural Gas Price - Per Mcf:						
United States	$ 3.63	$ 5.06	(28%)	$ 3.63	$ 5.02	(28%)
Canada	3.33	4.49	(26%)	3.23	4.58	(29%)
North America	3.51	4.82	(27%)	3.46	4.83	(28%)
Egypt	4.04	4.60	(12%)	3.86	4.61	(16%)
Australia	4.76	2.88	65%	4.45	2.71	64%
North Sea	8.65	21.43	(60%)	8.67	22.87	(62%)
Argentina	2.78	2.74	1%	2.84	2.57	11%
International	4.21	3.71	13%	4.10	3.65	12%
Total(2)	3.76	4.44	(15%)	3.70	4.43	(16%)
Average NGL Price - Per barrel:						
United States	$ 28.25	$ 54.36	(48%)	$ 33.51	$ 51.03	(34%)
Canada	31.01	46.93	(34%)	35.02	44.47	(21%)
North America	28.62	52.74	(46%)	33.76	49.53	(32%)
Egypt			NM		66.37	NM
North Sea	65.45	65.45	0%	73.60	65.45	12%
Argentina	16.25	26.45	(39%)	21.15	28.20	(25%)
International	32.41	26.62	22%	40.71	29.06	40%
Total	28.96	50.20	(42%)	34.57	47.44	(27%)

(1) Reflects a per-barrel decrease of $0.71 and $1.33 from derivative activities for the 2012 third quarter and nine-month period, respectively, and a decrease of $2.58 and $3.27 from derivative activities for the comparative 2011 third quarter and nine-month period, respectively.

(2) Reflects a per-Mcf increase of $0.50 and $0.52 from derivative activities for the 2012 third quarter and nine-month period, respectively, and an increase of $0.31 from derivative activities for each of the comparative 2011 third quarter and nine-month period.

NM Not meaningful

Third-Quarter 2012 compared to Third-Quarter 2011

Crude Oil Revenues Crude oil revenues for the third quarter of 2012 totaled $3.2 billion, an $8 million increase from the comparative 2011 quarter, primarily the result of a one-percent increase in average realized prices. Crude oil accounted for 78 percent of oil and gas production revenues and 44 percent of worldwide production in the third quarter of 2012. Higher realized prices increased third-quarter 2012 revenues by $30 million compared to the prior-year quarter, while lower production volumes reduced revenues by $22 million.

Crude oil prices realized in the third quarter of 2012 averaged $102.62 per barrel, compared with $101.71 in the comparative prior-year quarter. International Dated Brent crudes and Heavy and Light Louisiana Sweet crudes from the Gulf Coast continue to be priced at a premium to WTI-based prices. We are realizing these premium prices on approximately 70 percent of our crude oil production. Our Egypt, Australia and North Sea regions, which comprise approximately 54 percent of our worldwide oil production, receive International Dated Brent pricing with third-quarter 2012 oil realizations averaging $112.54 compared with third-quarter 2011 realizations of $108.81. Our Gulf Coast regions, which comprise 16 percent of our worldwide oil production, had price realizations averaging $104.49 per barrel, as compared to 2011 realizations of $105.74 per barrel.

Worldwide production decreased two thousand barrels of oil per day (Mb/d) from the third quarter of 2011 to 341 Mb/d in the third quarter of 2012, driven by decreased international production and partially offset by increased U.S. production. Australia production decreased 11 Mb/d as a result of natural decline from our Pyrenees and Van Gogh fields. Egypt gross production decreased four percent from the year-ago period on natural decline while net production was down six percent. North Sea production decreased 1 Mb/d, as volumes from the newly-acquired Beryl assets largely offset the impact of third-quarter maintenance and turnaround activities. In the U.S., production increased 11 percent on new drilling and recompletion activity as well as acquisitions. The Permian region was up 10 Mb/d on increased drilling activity, primarily in the Deadwood, Spraberry, and Wolfcamp plays. The Central region was up 9 Mb/d on production from properties added in the Cordillera acquisition. The GOM onshore and offshore regions were down 6 Mb/d on Hurricane Isaac downtime and natural decline.

Natural Gas Revenues Gas revenues for the third quarter of 2012 totaled $788 million, down 15 percent from the third quarter of 2011. A one-percent increase in average production added $4 million to natural gas revenues as compared to the prior-year quarter, while a 15-percent decline in average realized prices decreased revenues by $142 million. Natural gas accounted for 19 percent of our oil and gas production revenues and 49 percent of our equivalent production.

Worldwide production grew 13 MMcf/d between the periods on production increases in the North Sea and Australia. North Sea production grew 52 MMcf/d on production from the recently-acquired Beryl assets. Daily production in Australia increased 27 MMcf/d on new contracts associated with the completion of facilities at Devil Creek. Production in the U.S. rose 5 MMcf/d on volumes from newly-acquired properties and increased drilling and recompletion activity. Volume gains were offset by production associated with divested properties, downtime associated with Hurricane Isaac, and natural decline resulting from our shift away from gas-focused drilling. Egypt gross production increased two percent while net production decreased 12 percent, a product of the terms of our production sharing contracts. Daily production in Canada was down 15 MMcf/d reflecting the impact of natural decline, plant maintenance, and lower gas-focused drilling and recompletion activity.

Year-to-Date 2012 compared to Year-to-Date 2011

Crude Oil Revenues Crude oil revenues for the first nine months of 2012 totaled $9.8 billion, $440 million higher than the comparative 2011 period, the result of a two-percent increase in average realized prices and a two-percent increase in worldwide production. Crude oil accounted for 78 percent of oil and gas production revenues and 45 percent of worldwide production, compared with 75 percent and 45 percent, respectively, in the 2011 period. Higher production volumes added $271 million to the increase in revenues compared to the first nine months of 2011, while higher realized prices contributed an additional $169 million.

Crude oil prices realized in the first nine months of 2012 averaged $103.83 per barrel, compared with $102.00 in the comparative prior-year period. Our Egypt, Australia, North Sea, and GOM regions, which comprise approximately 72 percent of our worldwide oil production averaged oil realizations of $111.00 compared with realizations of $108.42 in the 2011 period.

Worldwide production increased 8 Mb/d to 345 Mb/d in the first nine months of 2012, driven by increased production in the U.S. and the North Sea. In the U.S., production increased 10 percent on new drilling and recompletion activity as well as from acquisitions. The Permian region was up 9 Mb/d on increased drilling activity, primarily in the Deadwood, Spraberry, and Wolfcamp plays. The Central region was up 5 Mb/d on production from properties added in the Cordillera acquisition. Production in the GOM onshore and offshore regions was down 2 Mb/d on Hurricane Isaac downtime. North Sea production increased 9 Mb/d, as volumes from the newly-acquired Beryl assets more than offset the impact of third-quarter maintenance activities. Australia production decreased 9 Mb/d as a result of natural decline from our Pyrenees and Van Gogh fields. Egypt gross production was down two percent over the year-ago period while net production was down five percent, a product of the terms of our production sharing contracts.

Natural Gas Revenues Gas revenues for the first nine months of 2012 totaled $2.3 billion, down 15 percent from the comparative 2011 period. A two-percent increase in average production added $56 million to natural gas revenues, while a 16-percent decrease in average realized prices reduced revenues by $455 million. Natural gas accounted for 19 percent of our oil and gas production revenues and 50 percent of our equivalent production, compared to 22 and 51 percent, respectively, for the 2011 period. As a whole our international regions, which contribute approximately one-third of our worldwide gas production, benefitted from higher realized prices as compared to the first nine months of 2011.

Worldwide production grew 47 MMcf/d between the periods on production increases in the North Sea, Australia, and Argentina. North Sea production grew 60 MMcf/d on production from the recently-acquired Beryl assets. Daily production in Australia increased 34 MMcf/d on new contracts associated with the recently completed facilities at Devil Creek. Argentina s production was up 7 MMcf/d from recompletions and new drilling, primarily associated with the country s Gas Plus program. Daily production in the U.S. and Canada decreased 24 MMcf/d and 16 MMcf/d, respectively, as drilling and recompletion activity shifted from gas to liquids-rich properties. The production decrease in the U.S. was partially offset by volumes associated with properties acquired from Cordillera.

Operating Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and a boe basis. Our discussion may reference expenses on a boe basis, on an absolute dollar basis or both, depending on their relevance.

	For the Quarter Ended September 30,				For the Nine Months Ended September 30,			
	2012	2011	2012	2011	2012	2011	2012	2011
	(In millions)		(Per boe)		(In millions)		(Per boe)	
Depreciation, depletion and amortization:								
Oil and gas property and equipment								
Recurring	$ 1,206	$ 973	$ 17.00	$ 14.07	$ 3,535	$ 2,777	$ 16.72	$ 13.67
Additional	729	20	10.27	0.29	1,898	46	8.98	0.23
Other assets	94	72	1.33	1.04	268	207	1.27	1.02
Asset retirement obligation accretion	60	39	0.84	0.57	172	114	0.81	0.56
Lease operating costs	801	661	11.30	9.54	2,178	1,946	10.30	9.57
Gathering and transportation costs	86	72	1.22	1.02	235	221	1.11	1.09
Taxes other than income	167	244	2.36	3.53	627	663	2.97	3.26
General and administrative expense	124	112	1.76	1.61	384	327	1.82	1.61
Merger, acquisitions & transition	7	4	0.10	0.05	29	15	0.14	0.07
Financing costs, net	40	37	0.56	0.54	125	123	0.59	0.60
Total	$ 3,314	$ 2,234	$ 46.74	$ 32.26	$ 9,451	$ 6,439	$ 44.71	$ 31.68

Depreciation, Depletion and Amortization (DD&A) The following table details the changes in DD&A of oil and gas properties between the third quarters and nine-month periods of 2012 and 2011:

	For the Quarter Ended September 30, (In millions)	For the Nine Months Ended September 30, (In millions)
2011 DD&A	$ 973	$ 2,777
Volume change	36	154
DD&A Rate change	197	604
2012 DD&A	$ 1,206	$ 3,535

Oil and gas property recurring DD&A expense of $1.2 billion in the third quarter of 2012 increased $233 million compared to the prior-year quarter on an absolute dollar basis: $197 million on rate, $36 million from higher volumes. The Company s oil and gas property recurring DD&A rate increased $2.93 to $17.00 per boe compared to the prior-year period, reflecting acquisition and drilling costs that exceed our historical basis and lower proved reserve estimates on a decline in natural gas prices.

Oil and gas property recurring DD&A expense of $3.5 billion in the first nine months of 2012 increased $758 million compared to the prior-year period on an absolute dollar basis: $604 million on rate and $154 million from higher volumes. The Company s oil and gas property recurring DD&A rate increased $3.05 to $16.72 per boe compared to the prior-year period, reflecting acquisition and drilling costs that exceed our historical basis and lower proved reserve estimates on a decline in natural gas prices.

In addition, we recorded non-cash write-downs on the carrying value of our proved oil and gas property balances in Canada of $521 million ($390 million net of tax), $641 million ($480 million net of tax), and $721 million ($539 million net of tax) as of March 31, 2012, June 30, 2012, and September 30, 2012, respectively. Under the full-cost method of accounting, the Company is required to review the carrying value of its proved oil and gas properties each quarter on a country-by-country basis. Under these rules, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, net of related tax effects and discounted 10 percent per annum and adjusted for cash flow hedges. Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous

12 months, held flat for the life of the production, except where prices are defined by contractual arrangements. If average natural gas prices in the fourth quarter of 2012 are lower than average prices in the fourth quarter of 2011, we will likely record an additional write-down in Canada. The Company also recorded $8 million and $20 million of additional DD&A in the third quarter of 2012 and 2011, respectively, associated with impairments of new venture seismic activity in countries where Apache is pursuing exploration opportunities but has not yet established a presence. For the nine months ended September 30, 2012 and 2011, the Company recorded $15 million and $46 million of additional DD&A, respectively.

Lease Operating Expenses (LOE) LOE increased $140 million, or 21 percent, and $232 million, or 12 percent, on an absolute dollar basis, for the quarter and nine-month period ended September 30, 2012, relative to the comparable periods of 2011. On a per unit basis, LOE increased 18 percent to $11.30 per boe for the third quarter of 2012, as compared to the same prior-year period, and eight percent to $10.30 per boe for the first nine months of 2012, as compared to the prior-year nine-month period. LOE per boe for the third quarter of 2012 was significantly impacted by production downtime and higher costs associated with repairs at our Grand Isle 43 complex and major facility turnarounds in the North Sea and Canada. The following table identifies changes in Apache s LOE rate between the third quarters and nine-month periods of 2012 and 2011.

For the Quarter Ended September 30,		**For the Nine Months Ended September 30,**	
	Per boe		**Per boe**
2011 LOE	$ 9.54	2011 LOE	$ 9.57
Repairs and maintenance	0.74	Labor and pumper costs	0.33
Labor and pumper costs	0.52	Repairs and maintenance	0.23
Workovers	0.33	Non-operated costs	0.16
Other	0.10	Workovers	0.11
Acquisitions[1]	(0.37)	Other	(0.01)
Other decreased production	0.44	Acquisitions[1]	(0.19)
		Other decreased production	0.10
2012 LOE	$ 11.30	2012 LOE	$ 10.30

(1) Per-unit impact of acquisitions is shown net of associated production.

Gathering and Transportation Gathering and transportation costs totaled $86 million and $235 million in the third quarter and first nine months of 2012, respectively, up $14 million from both the third quarter and first nine months of 2011. On a per-unit basis, gathering and transportation costs of $1.22 and $1.11 for the third quarter and first nine months of 2012, respectively, were up 20 percent and two percent, respectively. The following table presents gathering and transportation costs paid by Apache directly to third-party carriers for each of the periods presented:

	For the Quarter Ended September 30,		**For the Nine Months Ended September 30,**	
	2012	**2011**	**2012**	**2011**
		(In millions)		
Canada	$ 38	$ 39	$ 121	$ 125
U.S.	20	17	52	47
Egypt	9	7	29	25
North Sea	18	7	28	19
Argentina	1	2	5	5
Total Gathering and transportation	$ 86	$ 72	$ 235	$ 221

North Sea costs for the quarter and first nine months of 2012 increased $11 million and $9 million, respectively, as compared to prior-year periods, on the acquisition of Mobil North Sea at the end of 2011. The U.S. costs for the third quarter and first nine months of 2012 increased $3 million and $5 million, respectively, as compared to the same prior-year periods primarily as a result of increased production in the Central region from our acquisition of Cordillera. Canada s costs for the third quarter and first nine months of 2012 decreased $1 million and $4 million, respectively, as compared to the same prior-year periods primarily from decreased activity in the region.

Taxes other than Income Taxes other than income totaled $167 million and $627 million for the third quarter and first nine months of 2012, a decrease of $77 million and $36 million, respectively, from the comparative prior-year periods. The following table presents a comparison of these expenses:

	For the Quarter Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
U.K. PRT	$ 62	$ 149	$ 332	$ 386
Severance taxes	56	54	162	159
Ad valorem taxes	26	25	75	78
Other	23	16	58	40
Total Taxes other than income	$ 167	$ 244	$ 627	$ 663

The North Sea Petroleum Revenue Tax (PRT) is assessed on qualifying fields in the U.K. North Sea. For the third quarter of 2012, U.K. PRT was $87 million lower than the 2011 period based on a decrease in net receipts, primarily driven by lower revenues as a result of lower production on qualifying fields during the third quarter. Severance and ad valorem tax expense remained relatively flat, consistent with revenue.

U.K. PRT for the first nine months of 2012 was $54 million lower when compared to the 2011 period based on a decrease in net receipts, primarily driven by lower revenues during the period. For the first nine months of 2012, property acquisitions increased severance taxes by $3 million as compared to the first nine months of 2011. Ad valorem taxes for the first nine months of 2012 decreased $3 million on lower realized oil and gas prices in Canada as compared to the prior-year period.

General and Administrative Expenses General and administrative expenses (G&A) for the third quarter and first nine months of 2012 increased $12 million and $57 million, respectively, from the comparable 2011 periods on additional expenses relating to personnel, office, and information technology costs in support of our major development projects, increased exploration activities, and acquisitions.

Financing Costs, Net Financing costs incurred during the period comprised the following:

	For the Quarter Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Interest expense	$ 132	$ 109	$ 371	$ 326
Amortization of deferred loan costs	2	1	5	4
Capitalized interest	(90)	(69)	(241)	(193)
Interest income	(4)	(4)	(10)	(14)
Financing costs, net	$ 40	$ 37	$ 125	$ 123

Net financing costs were up $3 million and $2 million in the third quarter and first nine months of 2012, respectively, compared to the same 2011 periods. The $23 million and $45 million increases in interest expense in the third quarter and first nine months of 2012 are associated with $3.0 billion of debt issued in April 2012. The $21 million and $48 million increases in capitalized interest in the third quarter of 2012 and the first nine months of 2012, respectively, are a direct result of higher unproved property balances from the Mobil North Sea and Cordillera acquisitions.

Provision for Income Taxes The Company estimates its annual effective income tax rate in recording its quarterly provision for income taxes in the various jurisdictions in which the Company operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the quarter in which they occur. Accordingly, the Company recorded the income tax impact of a $521 million, $641 million, and $721 million non-cash write-down of its Canadian proved oil and gas properties as a discrete item in the first, second, and third quarters of 2012, respectively.

As a part of the increase in the corporate income tax rate on North Sea oil and gas profits from 50 percent to 62 percent announced in March 2011, the U.K. government also proposed that the corporation income tax relief attributable to decommissioning expenditures in the North Sea remain at 50 percent. The related legislation concerning decommissioning expenditures was then introduced in Finance Bill 2012 and was enacted on July 17, 2012, upon receiving Royal Assent. As a result of this enacted legislation, the Company recorded a discrete non-recurring tax charge of $118 million in the third quarter of 2012.

The 2012 third-quarter provision for income taxes was $685 million, representing an effective income tax rate of 79 percent for the quarter. This effective rate reflects the impact of the $721 million Canadian non-cash write-down discussed above, the North Sea decommissioning tax rate adjustment charge, and foreign currency fluctuations on deferred taxes. Excluding these items, the third-quarter 2012 effective rate would have been 45 percent, an increase from 44 percent in the third quarter of 2011.

The 2012 first nine-months provision for income taxes was $1.9 billion, representing an effective income tax rate of 59 percent for the period. This effective rate reflects the impact of three quarterly Canadian non-cash write-downs discussed above, the North Sea decommissioning tax rate adjustment charge, and foreign currency fluctuations on deferred taxes. Excluding these items, the effective rate for the first nine months of 2012 would have been 43 percent, an increase from 42 percent in the comparative 2011 period. This difference was driven primarily by an increase in the U.K. corporate income tax rate on North Sea oil and gas profits from 50 percent to 62 percent, which was enacted in the third quarter of 2011.

Capital Resources and Liquidity

Operating cash flows are the Company s primary source of liquidity. We may also elect to utilize available committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the occasional sale of nonstrategic assets for all other liquidity and capital resource needs.

Apache s operating cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Significant deterioration in commodity prices negatively impacts our revenues, earnings and cash flows, and potentially our liquidity if spending does not trend downward as well. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile and have less impact than commodity prices in the short-term.

Apache s long-term operating cash flows are dependent on reserve replacement and the level of costs required for ongoing operations. Cash investments are required to fund activity necessary to offset the inherent declines in production and proven reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of our exploration and development activities and/or our ability to acquire additional reserves at reasonable costs.

We believe the liquidity and capital resource alternatives available to Apache, combined with internally-generated cash flows, will be adequate to fund short-term and long-term operations, including our capital spending program, repayment of debt maturities, and any amount that may ultimately be paid in connection with contingencies.

For additional information, please see Part II, Item 1A, Risk Factors of this Form 10-Q and Part I, Items 1 and 2, Business and Properties, and Item 1A, Risk Factors Related to Our Business and Operations, in our Annual Report on Form 10-K for our 2011 fiscal year.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the periods presented.

	For the Nine Months Ended September 30, 2012	2011
	(In millions)	
Sources of Cash and Cash Equivalents:		
Net cash provided by operating activities	$ 6,422	$ 7,171
Sale of oil and gas properties	26	202
Fixed rate debt borrowings	2,991	
Net commercial paper and bank loan borrowings	1,827	
Other		77
	11,266	7,450
Uses of Cash and Cash Equivalents:		
Capital expenditures[(1)]	$ 6,973	$ 5,230
Acquisitions	2,788	509
Equity investment in Yara Pilbara Holdings Pty Limited (YPHPL)	439	
Payments of fixed rate debt	400	
Net commercial paper and bank loan repayments		940
Dividends	246	230
Other	397	89
	11,243	6,998
Increase in cash and cash equivalents	$ 23	$ 452

(1) The table presents capital expenditures on a cash basis; therefore, the amounts differ from those discussed elsewhere in this document, which include accruals.

Net Cash Provided by Operating Activities Cash flows are our primary source of capital and liquidity and are impacted, both in the short-term and the long-term, by volatile oil and natural gas prices. The factors in determining operating cash flow are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation (ARO) accretion and deferred income tax expense, which affect earnings but do not affect cash flows.

Net cash provided by operating activities for the first nine months of 2012 totaled $6.4 billion, down $749 million from the first nine months of 2011. The decrease reflects the impact of a change in working capital during the first nine months of 2012.

For a detailed discussion of commodity prices, production, costs and expenses, refer to the Results of Operations of this Item 2. For additional detail of changes in operating assets and liabilities, see the statement of consolidated cash flows in Item 1, Financial Statements of this Form 10-Q.

Sale of Oil and Gas Properties During the first nine months of 2012, Apache completed the sale of certain properties in the U.S. and Canada for $26 million. In June 2011 Apache completed the sale of certain properties in Canada and the U.S. for $202 million.

Fixed Rate Debt Borrowings In April 2012 Apache issued $3 billion principal amount of senior unsecured notes. For further discussion of the note offering, please see Note 6 Debt of this Form 10-Q.

Capital Expenditures We fund exploration and development (E&D) activities primarily through operating cash flows and budget capital expenditures based on projected cash flows. We routinely adjust our capital budget on a quarterly basis in response to changing market conditions and operating cash flow forecasts.

Historically, we have used a combination of operating cash flows, borrowings under lines of credit and the commercial paper program and, from time to time, issues of public debt or common stock to fund significant acquisitions.

The following table details capital expenditures for each country in which we do business:

	For the Nine Months Ended September 30, 2012	2011
	(In millions)	
E&D Costs:		
United States	$ 3,608	$ 1,976
Canada	459	609
North America	4,067	2,585
Egypt	809	674
Australia	518	445
North Sea	703	618
Argentina	222	245
Other International	84	49
International	2,336	2,031
Worldwide E&D Costs	6,403	4,616
Gathering Transmission and Processing Facilities (GTP):		
United States	57	9
Canada	138	113
Egypt	15	74
Australia	338	255
Argentina	12	7
Total GTP Costs	560	458
Asset Retirement Costs	556	288
Capitalized Interest	241	193
Capital Expenditures, excluding acquisitions	7,760	5,555
Acquisitions, including GTP	3,421	493
Asset Retirement Costs - Acquired	33	75
Total Capital Expenditures	$ 11,214	$ 6,123

Worldwide E&D expenditures for the first nine months of 2012 totaled $6.4 billion, or 39 percent above the first nine months of 2011. E&D spending in North America, which was up 57 percent, totaled 64 percent of worldwide E&D spending. Expenditures in the U.S. increased 83 percent primarily on increased drilling activity in the Permian region, particularly in the Deadwood area, and in our Central region where our active horizontal drilling program in the Granite Wash and Cherokee plays continued to expand. U.S. expenditures also reflect an increase in leasehold acquisition efforts where we have spent over $600 million to gain new acreage positions in several prospects, including the Mississippian Lime play in Kansas and Nebraska, the Williston Basin play in Montana and multiple offshore blocks in the GOM Deepwater and Shelf regions. E&D spending in Canada decreased 25 percent from the prior year period as our drilling program has been re-focused to oil and liquids-rich plays given current North American gas prices.

E&D expenditures outside of North America increased 15 percent when compared to the first nine-months of 2011. E&D spending in Egypt was up $135 million on continued drilling activity across all its major basins. North Sea expenditures were up $85 million driven by Beryl field development activity. Australian expenditures were up $73 million, or 16 percent, as development activities ramped up in the third quarter of 2012.

We invested $560 million in GTP in the first nine months of 2012 compared to $458 million in the first nine months of 2011. The increase is primarily related to Australia, driven by the purchase of the Ningaloo Vision floating production storage and offloading vessel (FPSO) and expenditures for the Wheatstone LNG project.

We acquired $3.4 billion of oil and gas properties in the first nine months of 2012 compared to $493 million in the prior-year period. Acquisitions occur as attractive opportunities arise and, therefore, vary from year to year. For information regarding our acquisitions, please see Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

Equity Investment in YPHPL On January 31, 2012, a subsidiary of Apache Energy Limited completed the acquisition of a 49-percent interest in YPHPL (formerly Burrup Holdings Limited) for $439 million, including working capital adjustments. The transaction was funded with debt. The investment in YPHPL is accounted for under the equity method of accounting, with the balance recorded as a component of Deferred charges and other in Apache s consolidated balance sheet and results of operations recorded as a component of Other under Revenues and Other in the Company s statement of consolidated operations.

Payments of Fixed Rate Debt During the second quarter of 2012 Apache repaid the $400 million in aggregate principal amount of 6.25-percent notes that matured on April 15, 2012.

Dividends For the nine-month periods ended September 30, 2012 and 2011, the Company paid $189 million and $173 million, respectively, in dividends on its common stock. In each of the first nine months of 2012 and 2011, the Company also paid $57 million in dividends on its Series D Preferred Stock.

Liquidity

The following table presents a summary of our key financial indicators at the dates presented:

	September 30, 2012	December 31, 2011
	(In millions of dollars, except as indicated)	
Cash and cash equivalents	$ 318	$ 295
Total debt	11,634	7,216
Shareholders equity	30,714	28,993
Available committed borrowing capacity	1,508	3,300
Floating-rate debt/total debt	16%	0.4%
Percent of total debt-to-capitalization	27%	20%

Cash and cash equivalents We had $318 million in cash and cash equivalents as of September 30, 2012, compared to $295 million at December 31, 2011. Approximately $276 million of the cash was held by foreign subsidiaries, with the remaining $42 million held by Apache Corporation and U.S. subsidiaries. The cash held by foreign subsidiaries is subject to additional U.S. income taxes if repatriated. Almost all of the cash is denominated in U.S. dollars and, at times, is invested in highly-liquid investment grade securities with maturities of three months or less at the time of purchase.

Debt As of September 30, 2012, outstanding debt, which consisted of notes, debentures, commercial paper, and uncommitted bank lines, totaled $11.6 billion. Current debt includes $500 million 5.25-percent notes and $400 million 6.00-percent notes due within the next 12 months and $64 million borrowed under uncommitted overdraft lines in Argentina.

In April 2012 the Company issued $400 million principal amount of senior unsecured 1.75-percent notes maturing April 15, 2017, $1.1 billion principal amount of senior unsecured 3.25-percent notes maturing April 15, 2022, and $1.5 billion principal amount of senior unsecured 4.75-percent notes maturing April 15, 2043. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. We used the proceeds to fund the cash portion of the purchase price to acquire Cordillera, repay the $400 million in aggregate principal amount of 6.25-percent notes that matured on April 15, 2012, and for general corporate purposes.

Available committed borrowing capacity As of September 30, 2012, the Company had unsecured committed revolving syndicated bank credit facilities totaling $3.3 billion, of which $1.0 billion matures in August 2016 and $2.3 billion matures in June 2017. The facilities consist of a $1.7 billion facility and a $1.0 billion facility in the U.S., a $300 million facility in Australia, and a $300 million facility in Canada. As of September 30, 2012, available borrowing capacity under the Company s credit facilities was $1.5 billion.

The Company has available a $3.0 billion commercial paper program, which generally enables Apache to borrow funds for up to 270 days at competitive interest rates. The commercial paper program is fully supported by available borrowing capacity under committed credit facilities, which expire in 2016 and 2017. As of September 30, 2012, the Company had $1.8 billion in commercial paper outstanding, compared with no outstanding commercial paper as of December 31, 2011.

The Company was in compliance with the terms of all credit facilities as of September 30, 2012.

Percent of total debt to-capitalization The Company s September 30, 2012 debt-to-capitalization ratio was 27 percent, up from 20 percent at December 31, 2011.

<u>Non-GAAP Measures</u>

The Company makes reference to some measures in discussion of its financial and operating highlights that are not required by or presented in accordance with GAAP. Management uses these measures in assessing operating results and believes the presentation of these measures provides information useful in assessing the Company s financial condition and results of operations. These non-GAAP measures should not be considered as alternatives to GAAP measures and may be calculated differently from, and therefore may not be comparable to, similarly-titled measures used at other companies.

Adjusted Earnings

To assess the Company s operating trends and performance, management uses Adjusted Earnings, which is net income excluding certain items that management believes affect the comparability of operating results. Management believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported company earnings for items that may obscure underlying fundamentals and trends. The reconciling items below are the types of items management excludes and believes are frequently excluded by analysts when evaluating the operating trends and comparability of the Company s results.

	For the Quarter Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions, except per share data)			
Income Attributable to Common Stock (GAAP)	$ 161	$ 983	$ 1,276	$ 3,338
Adjustments:				
Canada proved property write-down, net of tax[1]	539		1,409	
North Sea decommissioning tax rate adjustment	118		118	
Unrealized foreign currency fluctuation impact on deferred tax expense	39	(99)	40	(68)
Merger, acquisitions & transition, net of tax[2]	4	2	17	9
North Sea income tax rate increase		274		218
Adjusted Earnings (Non-GAAP)	$ 861	$ 1,160	$ 2,860	$ 3,497
Net Income per Common Share Diluted (GAAP)	$ 0.41	$ 2.50	$ 3.27	$ 8.49
Adjustments:				
Canada proved property write-down, net of tax[1]	1.33		3.49	
North Sea decommissioning tax rate adjustment	0.30		0.30	
Unrealized foreign currency fluctuation impact on deferred tax expense	0.10	(0.25)	0.11	(0.17)
Merger, acquisitions & transition, net of tax[2]	0.02	0.01	0.05	0.02
North Sea income tax rate increase		0.69		0.55
Adjusted Earnings Per Share Diluted (Non-GAAP)	$ 2.16	$ 2.95	$ 7.22	$ 8.89

(1) A write-down of our Canadian proved property balances of $521 million, $641 million, and $721 million pre-tax was recorded in the first, second, and third quarters of 2012, for which a tax benefit of $131 million, $161 million, and $182 million was recognized, respectively. The tax effect was calculated utilizing the Canadian statutory rate currently in effect.

(2) Merger, acquisitions & transition costs recorded in the third quarter of 2012 and 2011 totaled $7 million and $4 million pre-tax, respectively, for which a tax benefit of $3 million and $2 million was recognized, respectively. For the first nine months of 2012 and 2011, merger, acquisitions & transition costs totaled $29 million and $15 million, respectively, for which a tax benefit of $12 million and $6 million was recognized, respectively. The tax effect was calculated utilizing the statutory rates in effect in each country where costs were incurred.

ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Risk

The Company s revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas and NGLs, which have historically been very volatile because of unpredictable events such as economic growth or retraction, weather and political climate. Our average crude oil realizations have increased one percent to $102.62 per barrel in the third quarter of 2012 from $101.71 per barrel in the comparable period of 2011. Our average natural gas price realizations have fallen, decreasing 15 percent to $3.76 per Mcf from $4.44 per Mcf in the comparable period of 2011.

We periodically enter into hedging activities on a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to manage fluctuations in cash flows resulting from changes in commodity prices. For the third quarter and first nine months of 2012, approximately 13 percent of our natural gas production in both periods, and approximately 12 and 14 percent, respectively, of our crude oil production was subject to financial derivative hedges.

Apache may use futures contracts, swaps and options to hedge commodity price risk. Realized gains or losses from the Company s price-risk management activities are recognized in oil and gas production revenues when the associated production occurs. Apache does not hold or issue derivative instruments for trading purposes.

On September 30, 2012, the Company had open natural gas derivative hedges in an asset position with a fair value of $138 million. A 10-percent increase in natural gas prices would reduce the fair value by approximately $13 million, while a 10-percent decrease in prices would increase the fair value by approximately $13 million. The Company also had open oil derivatives in a liability position with a fair value of $87 million. A 10-percent increase in oil prices would increase the liability by approximately $82 million, while a 10-percent decrease in prices would decrease the liability by approximately $67 million. These fair value changes assume volatility based on prevailing market parameters at September 30, 2012. See Note 3 Derivative Instruments and Hedging Activities of the Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for notional volumes and terms associated with the Company s derivative contracts.

Interest Rate Risk

The Company considers its interest rate risk exposure to be minimal as a result of fixing interest rates on approximately 84 percent of the Company s debt. At September 30, 2012, total debt included $1.9 billion of floating-rate debt. As a result, Apache s annual interest costs will fluctuate based on short-term interest rates on approximately 16 percent of our total debt outstanding at September 30, 2012. The impact on cash flow of a 10-percent change in the floating interest rate based on debt balances at September 30, 2012, would be approximately $461,000 per quarter.

Foreign Currency Risk

The Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. In Australia, oil production is sold under U.S. dollar contracts, and gas production is sold largely under fixed-price Australian dollar contracts. Approximately half the costs incurred for Australian operations are paid in U.S. dollars. In Canada, oil and gas prices and costs, such as equipment rentals and services, are generally denominated in Canadian dollars but heavily influenced by U.S. markets. Our North Sea production is sold under U.S. dollar contracts, and the majority of costs incurred are paid in British pounds. In Egypt, all oil and gas production is sold under U.S. dollar contracts, and the majority of the costs incurred are denominated in U.S. dollars. Argentine revenues and expenditures are largely denominated in U.S. dollars but are converted into Argentine pesos at the time of payment. Revenue and disbursement transactions denominated in Australian dollars, Canadian dollars, British pounds, and Argentine pesos are converted to U.S. dollar equivalents based on average exchange rates during the period.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of Other under Revenues and Other or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company s provision for income tax expense on the statement of consolidated operations. A 10-percent strengthening or weakening of the Australian dollar, Canadian dollar, British pound, and Argentine peso as of September 30, 2012, would result in a foreign currency net loss or gain, respectively, of approximately $190 million.

Forward-Looking Statements and Risk

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs, and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2011, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, plan continue or similar terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

the market prices of oil, natural gas, NGLs and other products or services;

our commodity hedging arrangements;

the integration of acquisitions;

the supply and demand for oil, natural gas, NGLs and other products or services;

production and reserve levels;

drilling risks;

economic and competitive conditions;

the availability of capital resources;

capital expenditure and other contractual obligations;

currency exchange rates;

weather conditions;

inflation rates;

the availability of goods and services;

legislative or regulatory changes;

the impact on our operations due to the change in government in Egypt;

terrorism or cyber attacks;

occurrence of property acquisitions or divestitures;

the securities or capital markets and related risks such as general credit, liquidity, market, and interest-rate risks; and

other factors disclosed under Items 1 and 2 Business and Properties Estimated Proved Reserves and Future Net Cash Flows, Item 1A Risk Factors, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A Quantitative and Qualitative Disclosures About Market Risk and elsewhere in our most recently filed Form 10-K, other risks and uncertainties in our third-quarter 2012 earnings release, other factors disclosed under Part II, Item 1A Risk Factors of this Form 10-Q and the Form 10-Q for the quarter ended June 30, 2012, and other filings that we make with the Securities and Exchange Commission.

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

ITEM 4 CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

G. Steven Farris, the Company s Chairman and Chief Executive Officer, in his capacity as principal executive officer, and Thomas P. Chambers, the Company s Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2012, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company s disclosure controls and procedures were effective, providing effective means to ensure that information we are required to disclose under applicable laws and regulations is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

We periodically review the design and effectiveness of our disclosure controls, including compliance with various laws and regulations that apply to our operations both inside and outside the United States. We make modifications to improve the design and effectiveness of our disclosure controls, and may take other corrective action, if our reviews identify deficiencies or weaknesses in our controls.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the period covered by this Quarterly Report on Form 10-Q that materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Please refer to both Part I, Item 3 of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2011 (filed with the SEC on February 29, 2012) and Part I, Item 1 of this Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2012 for a description of material legal proceedings.

ITEM 1A. RISK FACTORS

Please refer to the risk factors as previously disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2011, and as noted above in Part I, Item 3 of this Form 10-Q. For the nine months ending September 30, 2012, Apache notes the following updated risk factors:

Our operations involve a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents.

Our operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil and natural gas, including:

well blowouts, explosions, and cratering;

pipeline ruptures and spills;

fires;

formations with abnormal pressures;

- equipment malfunctions;

- hurricanes and/or cyclones, which could affect our operations in areas such as on- and offshore the Gulf Coast and Australia, and other natural disasters; and

- surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Failure or loss of equipment, as the result of equipment malfunctions, cyber attacks, or natural disasters such as hurricanes, could result in property damages, personal injury, environmental pollution, and other damages for which we could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, or fire at a location where our equipment and services are used, or ground water contamination from hydraulic fracturing chemical additives may result in substantial claims for damages. Ineffective containment of a drilling well blowout, pipeline rupture, or surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives could result in extensive environmental pollution and substantial remediation expenses.

If a significant amount of our production is interrupted, our containment efforts prove to be ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows and, in turn, our results of operations could be materially and adversely affected.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have experienced cyber attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

None

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

*31.1	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Executive Officer.
*31.2	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Financial Officer.
*32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Executive Officer and Principal Financial Officer.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy 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.
*	Filed herewith

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 hereunto duly authorized.

	APACHE CORPORATION
Dated: November 7, 2012	/s/ THOMAS P. CHAMBERS Thomas P. Chambers Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Dated: November 7, 2012	/s/ REBECCA A. HOYT Rebecca A. Hoyt Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)