FNB CORP/FL/
Form 10-Q
August 05, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

x **Quarterly Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934**
For the quarterly period ended June 30, 2011

¨ **Transition Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934**
For the transition period from _______ to _______

Commission file number 001-31940

F.N.B. CORPORATION

(Exact name of registrant as specified in its charter)

Florida	**25-1255406**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
One F.N.B. Boulevard, Hermitage, PA	**16148**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: **724-981-6000**

(Former name, former address and former fiscal year, if changed since last report)

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 ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its 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 ¨

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 definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x Accelerated Filer ¨ Non-accelerated Filer ¨ Smaller reporting company ¨

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

APPLICABLE ONLY TO CORPORATE ISSUERS:

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at July 31, 2011
Common Stock, $0.01 Par Value	127,024,866 Shares

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F.N.B. CORPORATION

FORM 10-Q

June 30, 2011

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F.N.B. CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

Dollars in thousands, except par value

	June 30, 2011 (Unaudited)	December 31, 2010
Assets		
Cash and due from banks	$ 172,401	$ 115,556
Interest bearing deposits with banks	16,732	16,015
Cash and Cash Equivalents	189,133	131,571
Securities available for sale	820,847	738,125
Securities held to maturity (fair value of $1,038,434 and $959,414)	1,010,672	940,481
Residential mortgage loans held for sale	9,922	12,700
Loans, net of unearned income of $45,019 and $42,183	6,702,595	6,088,155
Allowance for loan losses	(109,224)	(106,120)
Net Loans	6,593,371	5,982,035
Premises and equipment, net	126,061	115,956
Goodwill	567,378	528,720
Core deposit and other intangible assets, net	34,580	32,428
Bank owned life insurance	208,714	208,051
Other assets	296,485	269,848
Total Assets	$ 9,857,163	$ 8,959,915
Liabilities		
Deposits:		
Non-interest bearing demand	$ 1,267,554	$ 1,093,230
Savings and NOW	3,853,257	3,423,844
Certificates and other time deposits	2,276,408	2,129,069
Total Deposits	7,397,219	6,646,143
Other liabilities	103,492	97,951
Short-term borrowings	728,300	753,603
Long-term debt	221,061	192,058
Junior subordinated debt	203,941	204,036
Total Liabilities	8,654,013	7,893,791
Stockholders Equity		
Common stock $0.01 par value		
Authorized 500,000,000 shares		
Issued 127,240,016 and 114,902,454 shares	1,267	1,143
Additional paid-in capital	1,219,663	1,094,713
Retained earnings	16,348	6,564
Accumulated other comprehensive loss	(30,716)	(33,732)
Treasury stock 215,117 and 155,369 shares at cost	(3,412)	(2,564)
Total Stockholders Equity	1,203,150	1,066,124

Total Liabilities and Stockholders Equity	$ 9,857,163	$ 8,959,915

See accompanying Notes to Consolidated Financial Statements

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F.N.B. CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

Dollars in thousands, except per share data

Unaudited

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Interest Income				
Loans, including fees	$ 85,189	$ 81,092	$ 169,899	$ 160,378
Securities:				
Taxable	10,975	11,323	21,489	22,576
Nontaxable	1,882	1,819	3,829	3,710
Dividends	12	18	131	37
Other	97	109	178	206
Total Interest Income	98,155	94,361	195,526	186,907
Interest Expense				
Deposits	14,054	16,776	28,649	34,330
Short-term borrowings	1,634	2,031	3,467	4,162
Long-term debt	1,655	2,091	3,283	4,637
Junior subordinated debt	2,118	1,982	4,150	3,892
Total Interest Expense	19,461	22,880	39,549	47,021
Net Interest Income	78,694	71,481	155,977	139,886
Provision for loan losses	8,551	12,239	16,779	24,203
Net Interest Income After Provision for Loan Losses	70,143	59,242	139,198	115,683
Non-Interest Income				
Impairment losses on securities		(1,313)		(9,539)
Non-credit related losses on securities not expected to be sold (recognized in other comprehensive income)		711		7,251
Net impairment losses on securities		(602)		(2,288)
Service charges	15,666	14,662	30,001	28,384
Insurance commissions and fees	3,664	3,849	7,810	8,173
Securities commissions and fees	2,130	1,771	4,102	3,328
Trust fees	3,947	3,188	7,657	6,346
Gain on sale of securities	38	47	92	2,437
Gain on sale of residential mortgage loans	376	808	1,143	1,375
Bank owned life insurance	1,372	1,247	2,604	2,312
Other	2,065	3,473	4,281	8,651
Total Non-Interest Income	29,258	28,443	57,690	58,718
Non-Interest Expense				
Salaries and employee benefits	36,528	33,392	74,910	66,517
Net occupancy	5,060	4,840	10,970	10,378
Equipment	4,925	4,606	9,400	9,139

Amortization of intangibles	1,805	1,679	3,601	3,366
Outside services	5,377	5,885	10,577	11,407
FDIC insurance	1,870	2,641	4,589	5,263
Merger related	161		4,307	
Other	12,643	10,041	24,572	22,457
Total Non-Interest Expense	68,369	63,084	142,926	128,527
Income Before Income Taxes	31,032	24,601	53,962	45,874
Income taxes	8,670	6,679	14,425	11,972
Net Income	$ 22,362	$ 17,922	$ 39,537	$ 33,902
Net Income per Share Basic	$ 0.18	$ 0.16	$ 0.32	$ 0.30
Net Income per Share Diluted	0.18	0.16	0.32	0.30
Cash Dividends per Share	0.12	0.12	0.24	0.24

See accompanying Notes to Consolidated Financial Statements

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F.N.B. CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Dollars in thousands, except per share data

Unaudited

	Compre-hensive Income	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total
Balance at January 1, 2011		$ 1,143	$ 1,094,713	$ 6,564	$ (33,732)	$ (2,564)	$ 1,066,124
Net income	$ 39,537			39,537			39,537
Change in other comprehensive income, net of tax	3,016				3,016		3,016
Comprehensive income	$ 42,553						
Common stock dividends ($0.24/share)				(29,753)			(29,753)
Issuance of common stock		124	123,180			(848)	122,456
Restricted stock compensation			1,832				1,832
Tax expense of stock-based compensation			(62)				(62)
Balance at June 30, 2011		$ 1,267	$ 1,219,663	$ 16,348	$ (30,716)	$ (3,412)	$ 1,203,150
Balance at January 1, 2010		$ 1,138	$ 1,087,369	$ (12,833)	$ (30,633)	$ (1,739)	$ 1,043,302
Net income	$ 33,902			33,902			33,902
Change in other comprehensive income, net of tax	5,275				5,275		5,275
Comprehensive income	$ 39,177						
Common stock dividends ($0.24/share)				(27,584)			(27,584)
Issuance of common stock		3	2,671			(778)	1,896
Restricted stock compensation			1,418				1,418
Tax expense of stock-based compensation			(205)				(205)
Balance at June 30, 2010		$ 1,141	$ 1,091,253	$ (6,515)	$ (25,358)	$ (2,517)	$ 1,058,004

See accompanying Notes to Consolidated Financial Statements

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F.N.B. CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Dollars in thousands

Unaudited

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Activities		
Net income	$ 39,537	$ 33,902
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	11,867	15,238
Provision for loan losses	16,779	24,203
Deferred taxes	2,183	(1,457)
Gain on sale of securities	(92)	(2,437)
Other-than-temporary impairment losses on securities		2,288
Tax expense of stock-based compensation	62	205
Net change in:		
Interest receivable	1,312	866
Interest payable	(620)	(923)
Trading securities	110,490	
Residential mortgage loans held for sale	2,778	5,522
Bank owned life insurance	(638)	(1,624)
Other, net	17,588	4,735
Net cash flows provided by operating activities	201,246	80,518
Investing Activities		
Net change in loans	(226,196)	(145,861)
Securities available for sale:		
Purchases	(138,672)	(261,012)
Sales	10,883	59,455
Maturities	162,150	163,233
Securities held to maturity:		
Purchases	(299,545)	(195,733)
Maturities	117,207	116,277
Purchase of bank owned life insurance	(26)	(22)
Increase in premises and equipment	(6,843)	(3,393)
Net cash received in business combinations	23,375	
Net cash flows used in investing activities	(357,667)	(267,056)
Financing Activities		
Net change in:		
Non-interest bearing deposits, savings and NOW accounts	288,317	144,500
Time deposits	(79,887)	9,936
Short-term borrowings	(50,414)	66,275
Increase in long-term debt	37,592	64,795
Decrease in long-term debt	(17,864)	(183,838)
Decrease in junior subordinated debt	(95)	(338)

Net proceeds from issuance of common stock	66,148	3,314
Tax expense of stock-based compensation	(62)	(205)
Cash dividends paid	(29,752)	(27,584)
Net cash flows provided by financing activities	213,983	76,855
Net Increase in Cash and Cash Equivalents	57,562	(109,683)
Cash and cash equivalents at beginning of period	131,571	310,550
Cash and Cash Equivalents at End of Period	$ 189,133	$ 200,867

See accompanying Notes to Consolidated Financial Statements

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F.N.B. CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Dollars in thousands, except share data

(Unaudited)

June 30, 2011

BUSINESS

F.N.B. Corporation (the Corporation) is a diversified financial services company headquartered in Hermitage, Pennsylvania. Its primary businesses include community banking, consumer finance, wealth management and insurance. The Corporation also conducts commercial leasing and merchant banking activities. The Corporation operates its community banking business through a full service branch network in Pennsylvania and Ohio and through a loan production office in Pennsylvania. The Corporation operates its wealth management and insurance businesses within the existing branch network. It also conducts selected consumer finance business in Pennsylvania, Ohio, Tennessee and Kentucky.

BASIS OF PRESENTATION

The Corporation s accompanying consolidated financial statements and these notes to the financial statements include subsidiaries in which the Corporation has a controlling financial interest. The Corporation owns and operates First National Bank of Pennsylvania (FNBPA), First National Trust Company, First National Investment Services Company, LLC, F.N.B. Investment Advisors, Inc., First National Insurance Agency, LLC, Regency Finance Company (Regency), F.N.B. Capital Corporation, LLC and Bank Capital Services, LLC, and includes results for each of these entities in the accompanying consolidated financial statements.

The accompanying consolidated financial statements include all adjustments that are necessary, in the opinion of management, to fairly reflect the Corporation s financial position and results of operations in accordance with U.S. generally accepted accounting principles (GAAP). All significant intercompany balances and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to the current period presentation. Events occurring subsequent to the date of the balance sheet have been evaluated for potential recognition or disclosure in the consolidated financial statements through the date of the filing of the consolidated financial statements with the Securities and Exchange Commission (SEC).

Certain information and note disclosures normally included in consolidated financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. The interim operating results are not necessarily indicative of operating results the Corporation expects for the full year. These interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Corporation s Annual Report on Form 10-K filed with the SEC on February 25, 2011.

USE OF ESTIMATES

The accounting and reporting policies of the Corporation conform with GAAP. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could materially differ from those estimates. Material estimates that are particularly susceptible to significant changes include the allowance for loan losses, securities valuations, goodwill and other intangible assets and income taxes.

COMMON STOCK

On May 18, 2011, the Corporation completed a public offering of 6,037,500 shares of common stock at a price of $10.70 per share, including 787,500 shares of common stock purchased by the underwriters pursuant to an over-allotment option, which the underwriters exercised in full. The net proceeds of the offering after deducting underwriting discounts and commissions and estimated offering expenses were $62,803.

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MERGERS AND ACQUISITIONS

On January 1, 2011, the Corporation completed its acquisition of Comm Bancorp, Inc. (CBI), a bank holding company based in Clarks Summit, Pennsylvania. On the acquisition date, CBI had $625,570 in assets, which included $445,271 in loans, and $561,796 in deposits. The transaction, valued at $75,547, resulted in the Corporation paying $17,202 in cash and issuing 5,940,742 shares of its common stock in exchange for 1,719,820 shares of CBI common stock. The assets and liabilities of CBI were recorded on the Corporation s balance sheet at their fair values as of January 1, 2011, the acquisition date, and CBI s results of operations have been included in the Corporation s consolidated statement of income since that date. CBI s banking affiliate, Community Bank and Trust Company, was merged into FNBPA on January 1, 2011. Based on a preliminary purchase price allocation, the Corporation recorded $38,658 in goodwill and $4,785 in core deposit intangible as a result of the acquisition. The Corporation has not yet finalized its determination of the fair values of certain acquired assets and liabilities and will adjust goodwill upon completion of the valuation process. None of the goodwill is deductible for income tax purposes.

Pending Acquisition

On June 15, 2011, the Corporation announced the signing of a definitive merger agreement to acquire Parkvale Financial Corporation (PFC), a savings and loan holding company with approximately $1,800,000 in assets based in Monroeville, Pennsylvania. The transaction is valued at approximately $130,000. Under the terms of the merger agreement, PFC shareholders will be entitled to receive 2.178 shares of F.N.B. Corporation common stock for each share of PFC common stock. PFC s banking affiliate, Parkvale Savings Bank, will be merged into FNBPA. The transaction is expected to be completed in the first quarter of 2012, pending regulatory approvals, the approval of shareholders of PFC and the satisfaction of other closing conditions.

Acquired Loans

Loans acquired in acquisitions after December 31, 2010 are recorded at fair value with no carryover of the related allowance for loan losses. Determining the fair value of the loans involves estimating the amount and timing of principal and interest cash flows expected to be collected on the loans and discounting those cash flows at a market rate of interest.

The excess of expected cash flows at acquisition over the estimated fair value is referred to as the accretable yield and is recognized into interest income over the remaining life of the loan. The difference between contractually required payments at acquisition and the expected cash flows to be collected at acquisition is referred to as the non-accretable yield. The non-accretable yield represents estimated future credit losses expected to be incurred over the life of the loan. Subsequent decreases in expected cash flows that are attributable, at least in part, to credit quality are recognized as impairments through a charge to the provision for loan losses resulting in an increase in the allowance for loan losses. Subsequent improvements in expected cash flows result in an increase to the accretable yield that is recognized into interest income over the remaining life of the loan using the interest method. The Corporation s evaluation of the amount of future cash flows that it expects to collect is performed in a similar manner as that used to determine its allowance for loan losses. Charge-offs of the principal amount on acquired loans would be first applied to the non-accretable discount portion of the fair value adjustment.

Acquired loans that met the criteria for non-accrual of interest prior to acquisition may be considered performing upon acquisition, regardless of whether the customer is contractually delinquent, if the Corporation can reasonably estimate the timing and amount of the expected cash flows on such loans and if the Corporation expects to fully collect the new carrying value of the loans. As such, the Corporation may no longer consider the loan to be non-accrual or non-performing and may accrue interest on these loans, including the impact of any accretable discount.

NEW ACCOUNTING STANDARDS

Comprehensive Income

In June 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-05, *Comprehensive Income,* with the intention of increasing the prominence of other comprehensive income in the financial statements. The FASB has eliminated the option to present components of other comprehensive income as part of the statement of changes in stockholders equity and will require it be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The single statement format would include the traditional income statement and the components and total other comprehensive income as well as total comprehensive income. In the two statement approach, the first statement would be the traditional income statement which would immediately be followed by a separate statement which includes the components of other comprehensive income, total other comprehensive income and total comprehensive income. These requirements should be applied retrospectively and are effective for the first interim or annual period beginning after December 15, 2011. Adoption of this standard is not expected to have a material effect on the financial statements, results of operations or liquidity of the Corporation.

Amendments to Fair Value Measurements

In May 2011, the FASB issued ASU No. 2011-04, *Fair Value Measurements,* to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with GAAP and International Financial Reporting Standards (IFRSs). The amendments explain how to measure fair value. They do not require additional fair value measurements and are not intended to establish valuation standards or affect valuation practices. The amendments result in common fair value measurement and disclosure requirements in GAAP and IFRSs. Some of the amendments clarify the application of existing fair value measurement requirements and others change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. Many of the previous fair value requirements are not changed by this standard. The amendments in this standard are to be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. Adoption of this standard is not expected to have a material effect on the financial statements, results of operations or liquidity of the Corporation.

Troubled Debt Restructurings

In April 2011, the FASB issued ASU No. 2011-02, *A Creditor s Determination of Whether a Restructuring Is a Troubled Debt Restructuring,* to address diversity in practice concerning determining whether a restructuring constitutes a troubled debt restructuring. This update specifies that in evaluating whether a restructuring is a troubled debt restructuring, a creditor must separately conclude both that a concession has been granted by the creditor and that the debtor is experiencing financial difficulties. Also, ASU No. 2011-02 provides clarifying guidance in determining whether a concession has been granted and whether a debtor is experiencing financial difficulties. In addition, the update precludes a creditor from using the effective interest rate test in the debtor s guidance on restructuring of payables when evaluating whether a restructuring is a troubled debt restructuring. These requirements are effective for the first interim or annual period beginning on or after June 15, 2011, and should be applied retrospectively to restructurings made during the period from the beginning of the annual period of adoption to the date of adoption. Adoption of this standard is not expected to have a material effect on the financial statements, results of operations or liquidity of the Corporation.

Disclosure of Supplementary Pro Forma Information for Business Combinations

In December 2010, the FASB issued ASU No. 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations,* to address diversity in practice concerning pro forma revenue and earnings disclosure requirements for business combinations. This update specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The update also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination(s) included in the reported pro forma revenue and earnings. These requirements are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Adoption of this standard did not have a material effect on the financial statements, results of operations or liquidity of the Corporation.

Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses

In July 2010, the FASB issued ASU No. 2010-20, *Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses,* to provide financial statement users with greater transparency about credit quality of financing receivables and allowance for credit losses. This update requires additional disclosures as of the end of a reporting period and additional disclosures about activity that occurs during a reporting period that will assist financial statement users in assessing credit risk exposures and evaluating the adequacy of the allowance for credit losses.

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The additional disclosures are required to be provided on a disaggregated basis. ASU No. 2010-20 defines two levels of disaggregation and provides additional implementation guidance to determine the appropriate level of disaggregation of information. The disclosures should facilitate evaluation of the nature of the credit risk inherent in a portfolio of financing receivables, how that risk is analyzed and assessed in arriving at the allowance for credit losses, and the changes and reasons for those changes in the allowance for credit losses.

The disclosures as of the end of a reporting period were effective for interim and annual reporting periods ending on or after December 15, 2010. The disclosures about activity that occurs during a reporting period are effective for interim and annual reporting periods beginning on or after December 15, 2010 and are included in this Report. Adoption of this standard did not have a material effect on the financial statements, results of operations or liquidity of the Corporation.

SECURITIES

The amortized cost and fair value of securities are as follows:

Securities Available For Sale:

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
June 30, 2011				
U.S. Treasury and other U.S. government agencies and corporations	$ 332,046	$ 1,329	$ (91)	$ 333,284
Residential mortgage-backed securities:				
Agency mortgage-backed securities	234,465	6,683		241,148
Agency collateralized mortgage obligations	184,665	2,320		186,985
Non-agency collateralized mortgage obligations	34	1		35
States of the U.S. and political subdivisions	43,910	1,048	(1)	44,957
Collateralized debt obligations	19,288		(12,683)	6,605
Other debt securities	6,859		(913)	5,946
Total debt securities	821,267	11,381	(13,688)	818,960
Equity securities	1,593	332	(38)	1,887
	$ 822,860	$ 11,713	$ (13,726)	$ 820,847
December 31, 2010				
U.S. Treasury and other U.S. government agencies and corporations	$ 299,861	$ 1,395	$ (688)	$ 300,568
Residential mortgage-backed securities:				
Agency mortgage-backed securities	205,443	6,064		211,507
Agency collateralized mortgage obligations	146,977	1,081	(192)	147,866
Non-agency collateralized mortgage obligations	37	1		38
States of the U.S. and political subdivisions	57,830	934	(26)	58,738
Collateralized debt obligations	19,288		(13,314)	5,974
Other debt securities	12,989		(1,744)	11,245
Total debt securities	742,425	9,475	(15,964)	735,936
Equity securities	1,867	381	(59)	2,189
	$ 744,292	$ 9,856	$ (16,023)	$ 738,125

Securities Held To Maturity:

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
June 30, 2011				
U.S. Treasury and other U.S. government agencies and corporations	$ 4,666	$ 229	$	$ 4,895
Residential mortgage-backed securities:				
Agency mortgage-backed securities	758,325	26,724	(1,556)	783,493
Agency collateralized mortgage obligations	62,673	609	(164)	63,118
Non-agency collateralized mortgage obligations	28,347	243	(908)	27,682
States of the U.S. and political subdivisions	152,574	3,383	(311)	155,646
Collateralized debt obligations	2,502		(508)	1,994
Other debt securities	1,585	25	(4)	1,606
	$ 1,010,672	$ 31,213	$ (3,451)	$ 1,038,434
December 31, 2010				
U.S. Treasury and other U.S. government agencies and corporations	$ 4,925	$ 212	$	$ 5,137
Residential mortgage-backed securities:				
Agency mortgage-backed securities	688,575	23,878	(3,079)	709,374
Agency collateralized mortgage obligations	71,102	511	(889)	70,724
Non-agency collateralized mortgage obligations	33,950	328	(1,331)	32,947
States of the U.S. and political subdivisions	137,210	1,735	(1,630)	137,315
Collateralized debt obligations	3,132		(778)	2,354
Other debt securities	1,587	18	(42)	1,563
	$ 940,481	$ 26,682	$ (7,749)	$ 959,414

The Corporation classifies securities as trading securities when management intends to sell such securities in the near term. Such securities are carried at fair value, with unrealized gains (losses) reflected through the consolidated statement of income. The Corporation acquired securities in conjunction with the CBI acquisition that the Corporation classified as trading securities. The Corporation both acquired and sold these trading securities during the first quarter of 2011. As of June 30, 2011 and December 31, 2010, the Corporation did not hold any trading securities.

Gross gains and gross losses were realized on sales of securities as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Gross gains	$ 38	$ 47	$ 288	$ 2,437
Gross losses			(196)	
	$ 38	$ 47	$ 92	$ 2,437

The gross gains for the six months ended June 30, 2010 included a gain of $2,291 relating to the sale of a $6,016 U.S. government agency security and $52,625 of mortgage backed securities. These securities were sold to better position the balance sheet.

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As of June 30, 2011, the amortized cost and fair value of securities, by contractual maturities, were as follows:

	Available for Sale		Held to Maturity	
	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Due in one year or less	$ 40,243	$ 40,720	$ 6,339	$ 6,438
Due from one to five years	289,370	290,091	16,728	17,443
Due from five to ten years	12,671	12,996	36,047	36,875
Due after ten years	59,819	46,985	102,213	103,385
	402,103	390,792	161,327	164,141
Residential mortgage-backed securities:				
Agency mortgage-backed securities	234,465	241,148	758,325	783,493
Agency collateralized mortgage obligations	184,665	186,985	62,673	63,118
Non-agency collateralized mortgage obligations	34	35	28,347	27,682
Equity securities	1,593	1,887		
	$ 822,860	$ 820,847	$ 1,010,672	$ 1,038,434

Maturities may differ from contractual terms because borrowers may have the right to call or prepay obligations with or without penalties. Periodic payments are received on mortgage-backed securities based on the payment patterns of the underlying collateral.

At June 30, 2011 and December 31, 2010, securities with a carrying value of $705,270 and $651,299, respectively, were pledged to secure public deposits, trust deposits and for other purposes as required by law. Securities with a carrying value of $576,986 and $676,083 at June 30, 2011 and December 31, 2010, respectively, were pledged as collateral for short-term borrowings.

Following are summaries of the fair values and unrealized losses of securities, segregated by length of impairment:

Securities available for sale:

	Less than 12 Months		Greater than 12 Months		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
June 30, 2011						
U.S. Treasury and other U.S. government agencies and corporations	$ 57,646	$ (91)	$	$	$ 57,646	$ (91)
States of the U.S. and political subdivisions	1,193	(1)			1,193	(1)
Collateralized debt obligations			6,605	(12,683)	6,605	(12,683)
Other debt securities			5,946	(913)	5,946	(913)
Equity securities	28	(1)	636	(37)	664	(38)
	$ 58,867	$ (93)	$ 13,187	$ (13,633)	$ 72,054	$ (13,726)
December 31, 2010						
U.S. Treasury and other U.S. government agencies and corporations	$ 117,140	$ (688)	$	$	$ 117,140	$ (688)
Residential mortgage-backed securities:						
Agency collateralized mortgage obligations	22,616	(192)			22,616	(192)
States of the U.S. and political subdivisions	3,322	(26)			3,322	(26)
Collateralized debt obligations			5,974	(13,314)	5,974	(13,314)
Other debt securities	4,024	(62)	7,221	(1,682)	11,245	(1,744)

Equity securities			648	(59)	648	(59)
	$ 147,102	$ (968)	$ 13,843	$ (15,055)	$ 160,945	$ (16,023)

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Securities held to maturity:

	Less than 12 Months		Greater than 12 Months		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
June 30, 2011						
Residential mortgage-backed securities:						
Agency mortgage-backed securities	$ 180,079	$ (1,556)	$	$	$ 180,079	$ (1,556)
Agency collateralized mortgage obligations	27,885	(164)			27,885	(164)
Non-agency collateralized mortgage obligations			9,395	(908)	9,395	(908)
States of the U.S. and political subdivisions	16,519	(311)			16,519	(311)
Collateralized debt obligations			1,994	(508)	1,994	(508)
Other debt securities			1,324	(4)	1,324	(4)
	$ 224,483	$ (2,031)	$ 12,713	$ (1,420)	$ 237,196	$ (3,451)
December 31, 2010						
Residential mortgage-backed securities:						
Agency mortgage-backed securities	$ 156,544	$ (3,079)	$	$	$ 156,544	$ (3,079)
Agency collateralized mortgage obligations	39,074	(889)			39,074	(889)
Non-agency collateralized mortgage obligations	2,551	(12)	10,739	(1,319)	13,290	(1,331)
States of the U.S. and political subdivisions	47,125	(1,415)	2,319	(215)	49,444	(1,630)
Collateralized debt obligations			2,354	(778)	2,354	(778)
Other debt securities			1,288	(42)	1,288	(42)
	$ 245,294	$ (5,395)	$ 16,700	$ (2,354)	$ 261,994	$ (7,749)

As of June 30, 2011, securities with unrealized losses for less than 12 months include 4 investments in U.S. Treasury and other U.S. government agencies and corporations, 17 investments in residential mortgage-backed securities (15 investments in agency mortgage-backed securities and 2 investments in agency collateralized mortgage obligations (CMOs)), 15 investments in states of the U.S. and political subdivisions and 1 investment in an equity security. Securities with unrealized losses of greater than 12 months include 2 investments in residential mortgage-backed securities (non-agency CMOs), 13 investments in collateralized debt obligations (CDOs), 5 investments in other debt securities and 2 investments in equity securities as of June 30, 2011. The Corporation does not intend to sell the debt securities and it is not more likely than not the Corporation will be required to sell the securities before recovery of their amortized cost basis.

The Corporation s unrealized losses on CDOs relate to investments in trust preferred securities (TPS). The Corporation s portfolio of TPS consists of single-issuer and pooled securities. The single-issuer securities are primarily from money-center and large regional banks. The pooled securities consist of securities issued primarily by banks and thrifts, with some of the pools including a limited number of insurance companies. Investments in pooled securities are all in mezzanine tranches except for one investment in a senior tranche, and are secured by over-collateralization or default protection provided by subordinated tranches. The non-credit portion of unrealized losses on investments in TPS is attributable to temporary illiquidity and the uncertainty affecting these markets, as well as changes in interest rates.

Other-Than-Temporary Impairment

The Corporation evaluates its investment securities portfolio for other-than-temporary impairment (OTTI) on a quarterly basis. Impairment is assessed at the individual security level. The Corporation considers an investment security impaired if the fair value of the security is less than its cost or amortized cost basis.

When impairment of an equity security is considered to be other-than-temporary, the security is written down to its fair value and an impairment loss is recorded as a loss within non-interest income in the consolidated statement of income. When impairment of a debt security is considered to be other-than-temporary, the amount of the OTTI recorded as a loss within non-interest income and thereby recognized in earnings depends on whether the Corporation intends to sell the security or whether it is more likely than not that the Corporation will be required to sell the security before recovery of its amortized cost basis.

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If the Corporation intends to sell the debt security or more likely than not will be required to sell the security before recovery of its amortized cost basis, OTTI shall be recognized in earnings equal to the entire difference between the investment s amortized cost basis and its fair value.

If the Corporation does not intend to sell the debt security and it is not more likely than not the Corporation will be required to sell the security before recovery of its amortized cost basis, OTTI shall be separated into the amount representing credit loss and the amount related to all other market factors. The amount related to credit loss shall be recognized in earnings. The amount related to other market factors shall be recognized in other comprehensive income, net of applicable taxes.

The Corporation performs its OTTI evaluation process in a consistent and systematic manner and includes an evaluation of all available evidence. Documentation of the process is as extensive as necessary to support a conclusion as to whether a decline in fair value below cost or amortized cost is temporary or other-than-temporary and includes documentation supporting both observable and unobservable inputs and a rationale for conclusions reached. In making these determinations for pooled TPS, the Corporation consults with third-party advisory firms to provide additional valuation assistance.

This process considers factors such as the severity, length of time and anticipated recovery period of the impairment, recoveries or additional declines in fair value subsequent to the balance sheet date, recent events specific to the issuer, including investment downgrades by rating agencies and economic conditions in its industry, and the issuer s financial condition, repayment capacity, capital strength and near-term prospects.

For debt securities, the Corporation also considers the payment structure of the debt security, the likelihood of the issuer being able to make future payments, failure of the issuer of the security to make scheduled interest and principal payments, whether the Corporation has made a decision to sell the security and whether the Corporation s cash or working capital requirements or contractual or regulatory obligations indicate that the debt security will be required to be sold before a forecasted recovery occurs. For equity securities, the Corporation also considers its intent and ability to retain the security for a period of time sufficient to allow for a recovery in fair value. Among the factors that the Corporation considers in determining its intent and ability to retain the security is a review of its capital adequacy, interest rate risk position and liquidity. The assessment of a security s ability to recover any decline in fair value, the ability of the issuer to meet contractual obligations, the Corporation s intent and ability to retain the security, and whether it is more likely than not the Corporation will be required to sell the security before recovery of its amortized cost basis require considerable judgment.

Debt securities with credit ratings below AA at the time of purchase that are repayment-sensitive securities are evaluated using the guidance of ASC Topic 325, *Investments Other.* All other securities are required to be evaluated under ASC Topic 320, *Investments Debt Securities*.

The Corporation invested in TPS issued by special purpose vehicles (SPVs) which hold pools of collateral consisting of trust preferred and subordinated debt securities issued by banks, bank holding companies, thrifts and insurance companies. The securities issued by the SPVs are generally segregated into several classes known as tranches. Typically, the structure includes senior, mezzanine and equity tranches. The equity tranche represents the first loss position. The Corporation generally holds interests in mezzanine tranches. Interest and principal collected from the collateral held by the SPVs are distributed with a priority that provides the highest level of protection to the senior-most tranches. In order to provide a high level of protection to the senior tranches, cash flows are diverted to higher-level tranches if the principal and interest coverage tests are not met.

The Corporation prices its holdings of TPS using Level 3 inputs in accordance with ASC Topic 820, *Fair Value Measurements and Disclosures*, and guidance issued by the SEC. In this regard, the Corporation evaluates current available information in estimating the future cash flows of these securities and determines whether there have been favorable or adverse changes in estimated cash flows from the cash flows previously projected. The Corporation considers the structure and term of the pool and the financial condition of the underlying issuers. Specifically, the evaluation incorporates factors such as over-collateralization and interest coverage tests, interest rates and appropriate risk premiums, the timing and amount of interest and principal payments and the allocation of payments to the various tranches. Current estimates of cash flows are based on the most recent trustee reports, announcements of deferrals or defaults, and assumptions regarding expected future default rates, prepayment and recovery rates and other relevant information. In constructing these assumptions, the Corporation considers the following:

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- that current defaults would have no recovery;
- that some individually analyzed deferrals will cure at rates varying from 10% to 90% after the deferral period ends;
- recent historical performance metrics, including profitability, capital ratios, loan charge-offs and loan reserve ratios, for the underlying institutions that would indicate a higher probability of default by the institution;
- that institutions identified as possessing a higher probability of default would recover at a rate of 10% for banks and 15% for insurance companies;
- that financial performance of the financial sector continues to be affected by the economic environment resulting in an expectation of additional deferrals and defaults in the future;
- whether the security is currently deferring interest; and
- the external rating of the security and recent changes to its external rating.

The primary evidence utilized by the Corporation is the level of current deferrals and defaults, the level of excess subordination that allows for receipt of full principal and interest, the credit rating for each security and the likelihood that future deferrals and defaults will occur at a level that will fully erode the excess subordination based on an assessment of the underlying collateral. The Corporation combines the results of these factors considered in estimating the future cash flows of these securities to determine whether there has been an adverse change in estimated cash flows from the cash flows previously projected.

The Corporation s portfolio of trust preferred CDOs consists of 13 pooled issues and five single issue securities. One of the pooled issues is a senior tranche; the remaining 12 are mezzanine tranches. At June 30, 2011, the 13 pooled TPS had an estimated fair value of $8,599 while the single-issuer TPS had an estimated fair value of $7,271. The Corporation has concluded from the analysis performed at June 30, 2011 that it is probable that the Corporation will collect all contractual principal and interest payments on all of its single-issuer and pooled TPS sufficient to recover the amortized cost basis of the securities.

The Corporation did not record any impairment losses on securities for the six months ended June 30, 2011. The Corporation recognized net impairment losses on securities of $2,288 for the six months ended June 30, 2010 due to the write-down of securities that the Corporation deemed to be other-than-temporarily impaired.

At June 30, 2011, all 12 of the pooled trust preferred security investments on which OTTI has been recognized are classified as non-performing investments.

The following table presents a summary of the cumulative credit-related OTTI charges recognized as components of earnings for securities for which a portion of an OTTI is recognized in other comprehensive income:

	June 30, 2011	December 31, 2010
Beginning balance of the amount related to credit loss for which a portion of OTTI was recognized in other comprehensive income	$ (18,332)	$ (16,051)
Additions related to credit loss for securities with previously recognized OTTI		(2,235)
Additions related to credit loss for securities with initial OTTI		(46)

Ending balance of the amount related to credit loss for which a portion of OTTI was recognized in other comprehensive income	$ (18,332)	$ (18,332)

TPS continue to experience price volatility as the secondary market for such securities remains limited. Write-downs in 2010 were based on the individual securities credit performance and its ability to make its contractual principal and interest payments. Should credit quality deteriorate to a greater extent than projected, it is possible that additional write-downs may be required. The Corporation monitors actual deferrals and defaults as well as expected future deferrals and defaults to determine if there is a high probability for expected losses and contractual shortfalls of interest or principal, which could warrant further impairment. The Corporation evaluates its entire portfolio each quarter to determine if additional write-downs are warranted.

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The following table provides information relating to the Corporation s TPS as of June 30, 2011:

Deal Name	Class	Current Par Value	Amortized Cost	Fair Value	Unrealized Loss	Lowest Credit Ratings	Number of Issuers Currently Performing	Actual Defaults (as a percent of original collateral)	Actual Deferrals (as a percent of original collateral)	Projected Recovery Rates on Current Deferrals (1)	Expected Defaults (%) (2)
Pooled TPS:											
P1	C1	$ 5,500	$ 2,266	$ 1,044	$ (1,222)	C	42	20	19	37	10
P2	C1	4,889	2,746	780	(1,966)	C	41	14	20	31	12
P3	C1	5,561	4,218	1,494	(2,724)	C	51	12	6	18	14
P4	C1	3,994	2,852	860	(1,992)	C	51	15	9	34	13
P5	MEZ	483	358	197	(161)	C	16	19	13	63	11
P6	MEZ	1,909	1,087	589	(498)	C	21	17	19	35	9
P7	B3	2,000	726	302	(424)	C	21	29	9	34	9
P8	B1	3,028	2,386	816	(1,570)	C	50	14	22	38	13
P9	C	5,048	756	154	(602)	C	33	14	32	41	14
P10	C	507	461	84	(377)	C	50	13	14	29	11
P11	C	2,010	787	114	(673)	C	41	15	16	29	12
P12	A4L	2,000	645	171	(474)	C	25	16	23	51	13
Total OTTI		36,929	19,288	6,605	(12,683)		442	16	16	36	12
P13 (3)	SNR	2,384	2,502	1,994	(508)	BBB	18	13	16	37	9
Total Not OTTI		2,384	2,502	1,994	(508)		18	13	16	37	9
Total Pooled TPS		$ 39,313	$ 21,790	$ 8,599	$ (13,191)		460	16	16	36	12
Single Issuer TPS:											
S1		$ 2,000	$ 1,948	$ 1,612	$ (336)	BB+	1				
S2		2,000	1,912	1,641	(271)	BBB+	1				
S3		2,000	2,000	1,917	(83)	B+	1				
S4		1,000	999	777	(222)	BB+	1				
S5		1,300	1,328	1,324	(4)	BB+	1				
Total Single Issuer TPS		$ 8,300	$ 8,187	$ 7,271	$ (916)		5				
Total TPS		$ 47,613	$ 29,977	$ 15,870	$ (14,107)		465				

(1) Some current deferrals will cure at rates varying from 10% to 90% after five years.
(2) Expected future defaults as a percent of remaining performing collateral.
(3) Excess subordination represents the additional defaults in excess of both current and projected defaults that the CDO can absorb before the bond experiences any credit impairment. The P13 security had excess subordination as a percent of current collateral of 60.77% as of June 30, 2011.

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States of the U.S. and Political Subdivisions

The Corporation s municipal bond portfolio of $197,531 as of June 30, 2011 is highly rated with an average rating of AA and 99.7% of the portfolio rated A or better. General obligation bonds comprise 100% of the portfolio. Geographically, these support the Corporation s footprint as 77.6% of the securities are from municipalities located throughout Pennsylvania. The average holding size of the securities in the municipal bond portfolio is $936. Finally, this portfolio is supported by underlying insurance as 83.6% of the securities have credit support.

Non-Agency CMOs

The Corporation purchased $161,151 of non-agency CMOs from 2003 through 2005. These securities, which are classified as held to maturity, have a book value of $28,347 at June 30, 2011. Paydowns during the first six months of 2011 amounted to $5,604, an annualized paydown rate of 33.0%. At the time of purchase, these securities were all rated AAA, with an original average loan-to-value (LTV) ratio of 66.1% and original credit score of 724. At origination, the credit support, or the amount of loss the collateral pool could absorb before the AAA securities would incur a credit loss, ranged from 2.0% to 7.0%. The current credit support range is now 3.2% to 20.1%, due to paydowns and good credit performance through the first half of 2008. Beginning in the second half of 2008, national delinquencies, an early warning sign of potential default, began to accelerate on the collateral pools. The slight upward trend of the rate of delinquencies throughout 2010 continued into the first quarter of 2011 and have leveled off during the second quarter. All CMO holdings are current with regards to principal and interest.

The rating agencies monitor the underlying collateral performance of these non-agency CMOs for delinquencies, foreclosures and defaults. They also factor in trends in bankruptcies and housing values to ultimately arrive at an expected loss for a given piece of defaulted collateral. Based on deteriorating performance of the collateral, many of these types of securities have been downgraded by the rating agencies. For the Corporation s portfolio, six of the ten non-agency CMOs have been downgraded with one being downgraded this quarter.

The Corporation determines its credit related losses by running scenario analysis on the underlying collateral. This analysis applies default assumptions to delinquencies already in the pipeline, projects future defaults based in part on the historical trends for the collateral, applies a rate of severity and estimates prepayment rates. Because of the limited historical trends for the collateral, multiple default scenarios were analyzed including scenarios that significantly elevate defaults over the next 12 18 months. Based on the results of the analysis, the Corporation s management has concluded that there are currently no credit-related losses in its non-agency CMO portfolio.

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The following table provides information relating to the Corporation s non-agency CMOs as of June 30, 2011:

			Credit Rating		Credit Support %		Subordination Data								
							Delinquency %								
Security	Original Year	Book Value	S&P	Moody s	Original	Current	30 Day	60 Day	90 Day	% Foreclosure	% OREO	% Bankruptcy	% Total Delinquency	% LTV	Credit Score
1	2003	$ 3,247	AAA	n/a	2.5	5.8	1.4	0.1	0.6	0.8	0.0	0.5	3.4	52.1	738
2	2003	2,265	AAA	n/a	4.3	16.3	2.0	1.2	5.0	2.6	0.3	1.2	12.2	56.0	710
3	2003	1,519	AAA	n/a	2.0	6.5	0.6	0.5	1.5	1.3	0.2	1.1	5.1	47.3	742
4	2003	1,522	AAA	n/a	2.7	18.2	0.8	0.0	1.6	2.2	0.0	1.1	5.7	50.4	n/a
5	2004	3,720	AAA	Baa2	7.0	20.1	0.9	1.2	2.0	7.0	1.2	0.8	13.0	55.8	689
6	2004	2,631	AA+	n/a	5.3	10.4	0.6	0.0	2.4	3.1	0.0	1.9	8.0	46.5	734
7	2004	1,260	n/a	A1-	2.5	8.5	0.0	1.1	0.0	4.8	0.0	0.0	5.9	56.0	736
8	2004	1,881	AAA	Baa2	4.4	9.3	1.3	0.5	0.5	2.6	0.5	1.1	6.5	55.1	733
9	2005	6,518	CCC	Caa1	5.1	5.0	3.6	2.1	12.2	5.4	0.5	2.5	26.2	65.5	706
10	2005	3,784	CCC	B3	4.7	3.2	3.5	2.2	3.8	9.1	1.2	1.6	21.4	65.8	726
		$ 28,347			4.1	9.5								57.3	719

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FEDERAL HOME LOAN BANK STOCK

The Corporation is a member of the Federal Home Loan Bank (FHLB) of Pittsburgh. The FHLB requires members to purchase and hold a specified minimum level of FHLB stock based upon their level of borrowings, collateral balances and participation in other programs offered by the FHLB. Stock in the FHLB is non-marketable and is redeemable at the discretion of the FHLB. Both cash and stock dividends on FHLB stock are reported as income.

Members do not purchase stock in the FHLB for the same reasons that traditional equity investors acquire stock in an investor-owned enterprise. Rather, members purchase stock to obtain access to the low-cost products and services offered by the FHLB. Unlike equity securities of traditional for-profit enterprises, the stock of FHLB does not provide its holders with an opportunity for capital appreciation because, by regulation, FHLB stock can only be purchased, redeemed and transferred at par value.

At June 30, 2011 and December 31, 2010, the Corporation s FHLB stock totaled $26,057 and $26,564, respectively, and is included in other assets on the balance sheet. The Corporation accounts for the stock in accordance with ASC Topic 325, which requires the investment to be carried at cost and evaluated for impairment based on the ultimate recoverability of the par value.

The Corporation periodically evaluates its FHLB investment for possible impairment based on, among other things, the capital adequacy of the FHLB and its overall financial condition. The Federal Housing Finance Agency, the regulator of the FHLB, requires it to maintain a total capital-to-assets ratio of at least 4.0%. At March 31, 2011, the FHLB s capital ratio of 8.1% exceeded the regulatory requirement. Failure by the FHLB to meet this regulatory capital requirement would require an in-depth analysis of other factors including:

- the member s ability to access liquidity from the FHLB;
- the member s funding cost advantage with the FHLB compared to alternative sources of funds;
- a decline in the market value of FHLB s net assets relative to book value which may or may not affect future financial performance or cash flow;
- the FHLB s ability to obtain credit and source liquidity, for which one indicator is the credit rating of the FHLB;
- the FHLB s commitment to make payments taking into account its ability to meet statutory and regulatory payment obligations and the level of such payments in relation to the FHLB s operating performance; and
- the prospects of amendments to laws that affect the rights and obligations of the FHLB.

At June 30, 2011, the Corporation believes its holdings in the stock are ultimately recoverable at par value and, therefore, determined that FHLB stock was not other-than-temporarily impaired. In addition, the Corporation has ample liquidity and does not require redemption of its FHLB stock in the foreseeable future.

LOANS

Following is a summary of loans, net of unearned income:

	June 30, 2011	December 31, 2010

Commercial	$ 3,776,287	$ 3,337,992
Direct installment	1,039,270	1,002,725
Residential mortgages	676,574	622,242
Indirect installment	535,191	514,369
Consumer lines of credit	542,470	493,881
Commercial leases	93,273	79,429
Other	39,530	37,517
	$ 6,702,595	$ 6,088,155

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Commercial is comprised of both commercial real estate loans and commercial and industrial loans. Direct installment is comprised of fixed-rate, closed-end consumer loans for personal, family or household use, such as home equity loans and automobile loans. Residential mortgages consist of conventional mortgage loans for non-commercial properties. Indirect installment is comprised of loans written by third parties, primarily automobile loans. Consumer lines of credit includes home equity lines of credit (HELOC) and consumer lines of credit that are either unsecured or secured by collateral other than home equity. Commercial leases consist of loans for new or used equipment. Other is primarily comprised of mezzanine loans and student loans.

Unearned income on loans was $45,019 and $42,183 at June 30, 2011 and December 31, 2010, respectively.

The loan portfolio consists principally of loans to individuals and small- and medium-sized businesses within the Corporation s primary market area of Pennsylvania and northeastern Ohio. The portfolio also includes commercial loans in Florida, which totaled $180,232 or 2.7% of total loans as of June 30, 2011 compared to $195,281 or 3.2% of total loans as of December 31, 2010. In addition, the portfolio contains consumer finance loans to individuals in Pennsylvania, Ohio, Tennessee and Kentucky, which totaled $163,150 or 2.4% of total loans as of June 30, 2011 compared to $162,805 or 2.7% of total loans as of December 31, 2010.

The composition of the Corporation s commercial loan portfolio in Florida consisted of the following as of June 30, 2011: unimproved residential land (7.9%), unimproved commercial land (18.5%), improved land (3.2%), income producing commercial real estate (50.8%), residential construction (6.2%), commercial construction (12.1%) and owner-occupied (1.3%). The weighted average loan-to-value ratio for this portfolio based on most recent appraisals was 81.7% as of June 30, 2011.

The majority of the Corporation s loan portfolio consists of commercial loans. As of June 30, 2011 and December 31, 2010, commercial real estate loans were $2,353,519 and $2,115,492, or 35.1% and 34.7% of total loans, respectively. As of June 30, 2011, approximately 49.0% of the commercial real estate loans were owner-occupied, while the remaining 51.0% were non-owner-occupied. As of June 30, 2011 and December 31, 2010, the Corporation had commercial construction loans of $225,614 and $202,018, respectively, representing 3.4% and 3.3%, respectively, of total loans for those periods.

CREDIT QUALITY

Management monitors the credit quality of the Corporation s loan portfolio on an ongoing basis. Measurement of delinquency and past due status are based on the contractual terms of each loan.

Non-performing loans include non-accrual and restructured loans. Past due loans are reviewed on a monthly basis to identify loans for non-accrual status. The Corporation places a loan on non-accrual status and discontinues interest accruals generally when principal or interest is due and has remained unpaid for 90 to 180 days depending on the loan type. When a loan is placed on non-accrual status, all unpaid interest recognized in the current year is reversed and interest accrued in prior years is charged to the allowance for loan losses. Non-accrual loans may not be restored to accrual status until all delinquent principal and interest have been paid and the ultimate collectibility of the remaining principal and interest is reasonably assured. Restructured loans are loans in which the borrower has been granted a concession on the interest rate or the original repayment terms due to financial distress. Non-performing assets also include debt securities on which OTTI has been taken in the current or prior periods.

Following is a summary of non-performing assets:

	June 30, 2011	December 31, 2010
Non-accrual loans	$ 107,091	$ 115,589
Restructured loans	20,146	19,705
Total non-performing loans	127,237	135,294
Other real estate owned (OREO)	35,793	32,702
Total non-performing loans and OREO	163,030	167,996
Non-performing investments	6,605	5,974

Total non-performing assets	$ 169,635	$ 173,970

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	June 30, 2011	December 31, 2010
Asset quality ratios:		
Non-performing loans as a percent of total loans	1.90%	2.22%
Non-performing loans + OREO as a percent of total loans + OREO	2.42%	2.74%
Non-performing assets as a percent of total assets	1.72%	1.94%

Following is an age analysis of the Corporation s past due loans, by class:

	30-89 Days Past Due	>90 Days Past Due and Still Accruing	Non-Accrual	Total Past Due	Current	Total Loans
June 30, 2011						
Commercial	$ 14,152	$ 10,060	$ 97,174	$ 121,386	$ 3,654,901	$ 3,776,287
Direct installment	8,528	2,458	3,586	14,572	1,024,698	1,039,270
Residential mortgages	12,192	2,775	3,832	18,799	657,775	676,574
Indirect installment	4,297	260	908	5,465	529,726	535,191
Consumer lines of credit	857	479	851	2,187	540,283	542,470
Commercial leases	1,339	78	740	2,157	91,116	93,273
Other	45	5		50	39,480	39,530
	$ 41,410	$ 16,115	$ 107,091	$ 164,616	$ 6,537,979	$ 6,702,595
December 31, 2010						
Commercial	$ 17,101	$ 3,020	$ 106,724	$ 126,845	$ 3,211,147	$ 3,337,992
Direct installment	8,603	2,496	3,285	14,384	988,341	1,002,725
Residential mortgages	9,127	2,144	3,272	14,543	607,699	622,242
Indirect installment	5,659	394	750	6,803	507,566	514,369
Consumer lines of credit	1,581	571	588	2,740	491,141	493,881
Commercial leases	1,551	9	970	2,530	76,899	79,429
Other					37,517	37,517
	$ 43,622	$ 8,634	$ 115,589	$ 167,845	$ 5,920,310	$ 6,088,155

The Corporation utilizes the following categories to monitor credit quality within its commercial loan portfolio:

Pass	in general, the condition of the borrower and the performance of the loan is satisfactory or better
Special Mention	in general, the condition of the borrower has deteriorated although the loan performs as agreed
Substandard	in general, the condition of the borrower has significantly deteriorated and the performance of the loan could further deteriorate if deficiencies are not corrected
Doubtful	in general, the condition of the borrower has significantly deteriorated and the collection in full of both principal and interest is highly questionable or improbable

The use of these internally assigned credit quality categories within the commercial loan portfolio permits management s use of migration and roll rate analysis to estimate a quantitative portion of credit risk. The Corporation s internal credit risk grading system is based on past experiences with similarly graded loans and conforms with regulatory categories. In general, loan risk ratings within each category are reviewed on an ongoing basis according to the Corporation s policy for each class of loans. Each quarter, management analyzes the resulting ratings, as well as other external statistics and factors such as delinquency, to track the migration performance of the commercial loan portfolio. Loans that migrate toward the Pass credit category or within the Pass credit category generally have a lower risk of loss and therefore a lower risk factor compared to loans that migrate toward the Substandard or Doubtful credit categories which generally have a higher risk of loss and therefore a higher risk factor applied to those related loan balances.

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Following is a table showing commercial loans by credit quality category:

	Commercial Loan Credit Quality Categories				
	Pass	Special Mention	Substandard	Doubtful	Total
June 30, 2011					
Commercial PA	$ 3,293,685	$ 114,414	$ 182,169	$ 5,787	$ 3,596,055
Commercial FL	78,207	16,545	85,480		180,232
Commercial leases	91,937	518	818		93,273
	$ 3,463,829	$ 131,477	$ 268,467	$ 5,787	$ 3,869,560
December 31, 2010					
Commercial PA	$ 2,887,682	$ 80,409	$ 170,714	$ 3,906	$ 3,142,711
Commercial FL	83,444	38,664	73,173		195,281
Commercial leases	77,945	505	979		79,429
	$ 3,049,071	$ 119,578	$ 244,866	$ 3,906	$ 3,417,421

The Corporation uses payment status and delinquency migration analysis within the consumer and other loan classes to enable management to estimate a quantitative portion of credit risk. Each month, management analyzes payment activity, as well as other external statistics and factors such as volume, to determine how consumer loans are performing.

Following is a table showing consumer and other loans by payment activity:

	Consumer Loan Credit Quality by Payment Status		
	Performing	Non-Performing	Total
June 30, 2011			
Direct installment	$ 1,027,412	$ 11,858	$ 1,039,270
Residential mortgages	662,749	13,825	676,574
Indirect installment	534,211	980	535,191
Consumer lines of credit	541,402	1,068	542,470
Other	39,530		39,530
December 31, 2010			
Direct installment	$ 991,921	$ 10,804	$ 1,002,725
Residential mortgages	608,642	13,600	622,242
Indirect installment	513,619	750	514,369
Consumer lines of credit	493,075	806	493,881
Other			

	Fair Value Measurements at June 30, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$ —	$ 193	$ —	$ 193
Oil, natural gas and NGL derivatives	—	(11,289)	—	(11,289)
Total	$ —	$ (11,096)	$ —	$ (11,096)

	Fair Value Measurements at December 31, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				

Oil, natural gas and NGL derivatives	$—	$192	$—	$192
Oil, natural gas and NGL derivatives	—	(2,945)	—	(2,945)
Total	$—	$(2,753)	$—	$(2,753)

Additional disclosures related to derivative financial instruments are provided in Note 8. For purposes of fair value measurement, the Company determined that derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified at Level 2.

The Company accounts for additions and revisions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment at fair value on a non-recurring basis and has determined that these fair value measurements should be classified at Level 3. The following tables summarize the valuation of the Company’s assets and liabilities that were accounted for at fair value on a non-recurring basis for the periods ended June 30, 2014 and December 31, 2013 (in thousands).

	Fair Value Measurements at June 30, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(2,497)	$(2,497)
Total	$—	$—	$(2,497)	$(2,497)

	Fair Value Measurements at December 31, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(1,470)	$(1,470)
Total	$—	$—	$(1,470)	$(1,470)

No impairment to any equipment was recorded during the three months ended June 30, 2014 and December 31, 2013.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty’s system for processing at the counterparty’s facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty’s processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company’s remaining aggregate undiscounted minimum commitments under this agreement are $8.0 million at June 30, 2014. The Company paid $1.7 million and $1.0 million in processing and transportation fees under this agreement during the three months ended June 30, 2014 and 2013, respectively, and $2.8 million and $1.8 million during the six months ended June 30, 2014 and 2013, respectively.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such rigs. These contracts establish daily rates for the drilling rigs and the term of the Company’s commitment for the drilling services to be provided, which have typically been for one year or less, although the Company has recently begun to enter into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that are experiencing heavy demand for drilling rigs. The Company would incur a termination obligation if the Company elected to terminate a contract and the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company’s undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $54.7 million at June 30, 2014.

At June 30, 2014, the Company had agreed to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed, the Company will have undiscounted minimum outstanding aggregate commitments for its participation in these wells of approximately $30.3 million at June 30, 2014, which it expects to incur within the next few months.

From time to time, the Company enters into contracts with third parties for geological and geophysical data on certain prospects to assist in the exploration of these prospects. The undiscounted minimum commitments under these agreements totaled approximately $4.1 million at June 30, 2014, which the Company expects to incur within the next few months.

Legal Proceedings

The Company is a defendant in several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company’s financial position, results of operations or cash flows.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 11 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities
The following table summarizes the Company's current accrued liabilities at June 30, 2014 and December 31, 2013 (in thousands).

	June 30, 2014	December 31, 2013
Accrued evaluated and unproved and unevaluated property costs	$86,066	$52,605
Accrued support equipment and facilities costs	293	—
Accrued cost to issue equity	87	—
Accrued stock-based compensation	109	56
Accrued lease operating expenses	8,751	6,251
Accrued interest on borrowings under Credit Agreement	95	141
Accrued asset retirement obligations	477	175
Accrued partners' share of joint interest charges	4,109	1,173
Other	5,142	3,586
Total accrued liabilities	$105,129	$63,987

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2014 and 2013 (in thousands).

	Six Months Ended June 30,	
	2014	2013
Cash paid for interest expense, net of amounts capitalized	$3,058	$1,817
Asset retirement obligations related to mineral properties	2,343	751
Asset retirement obligations related to support equipment and facilities	132	4
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	34,444	(6,859)
Increase (decrease) in liabilities for support equipment and facilities	293	(914)
Increase in liabilities for accrued cost to issue equity	86	—
Issuance of restricted stock units for Board and advisor services	197	87
Issuance of common stock for advisor services	10	17
Stock-based compensation expense recognized as liability	1,200	284
Transfer of inventory from oil and natural gas properties	133	191

NOTE 12 - SUBSIDIARY GUARANTORS
Matador filed a registration statement on Form S-3 with the SEC in 2013, which became effective on May 9, 2013, and a registration statement on Form S-3 with the SEC in 2014, which became effective upon filing on May 22, 2014, registering, in each case, among other securities, senior and subordinated debt securities. The subsidiaries of Matador (the "Subsidiaries") are co-registrants with Matador on each Form S-3, and the registration statements register guarantees of debt securities by the Subsidiaries. As of June 30, 2014, the Subsidiaries are 100% owned by Matador and any guarantees by the Subsidiaries will be full and unconditional (except for customary release provisions). Matador has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to Matador. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by Matador, such guarantees will constitute joint and several obligations.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2013 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Annual Report. The Annual Report is accessible on the SEC's website at www.sec.gov and on our website at www.matadorresources.com. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with the "Risk Factors" section of the Annual Report and in conjunction with "Cautionary Note Regarding Forward-Looking Statements" below for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

In this Quarterly Report on Form 10-Q (the "Quarterly Report"), references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole and references to "Matador" refer solely to Matador Resources Company.

For certain oil and natural gas terms used in this report, please see the "Glossary of Oil and Natural Gas Terms" included with the Annual Report.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "inter "may," "might," "potential," "predict," "project," "should" or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the success of our drilling program, the timing and amount of planned capital expenditures, having sufficient cash flow from operations together with available borrowing capacity under our revolving credit facility, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, availability of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Quarterly Report and in other documents that we file with or furnish to the SEC, all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;

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- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof;
- our plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical; and
- other factors discussed in the Annual Report.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, we have a large exploratory leasehold position in Southwest Wyoming and adjacent areas in Utah and Idaho where we are testing the Meade Peak shale.

Second Quarter and Year-to-Date Highlights

Our total oil equivalent production for the second quarter of 2014 was 1.4 million BOE. Our average daily oil equivalent production for the second quarter of 2014 was 15,424 BOE per day, of which 8,809 Bbl per day, or 57%, was oil and 39.7 MMcf per day, or 43%, was natural gas. These quarterly production results were the best in our Company's history. Our total oil production for the second quarter of 2014 of 802,000 Bbl and our average daily oil production of 8,809 Bbl per day were also record quarterly results. We achieved these results despite having as much as 10% to 15% of our total production capacity shut in or restricted at various times during the second quarter while offsetting wells were drilled and completed and pipeline connections were being made. For the six months ended June 30, 2014, our total oil equivalent production was 2.5 million BOE, averaging 13,673 BOE per day, and our total oil production was 1.5 million Bbl, averaging 8,080 Bbl per day. These results were also the best reported for any six-month period in our Company's history.

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During the second quarter of 2014, our oil and natural gas revenues were $99.1 million, an increase of 70% from oil and natural gas revenues of $58.2 million during the second quarter of 2013. This increase was primarily attributable to the 79% increase in our oil production to 802,000 Bbl in the second quarter of 2014, as compared to 447,000 Bbl produced in the second quarter of 2013. This increase in oil production is due primarily to our drilling operations in the Eagle Ford shale as well as initial production contributions from newly drilled wells in the Permian Basin. For the six months ended June 30, 2014, our oil and natural gas revenues were $178.0 million, an increase of 51% from oil and natural gas revenues of $117.5 million in the first six months of 2013. For the three months ended June 30, 2014, our Adjusted EBITDA was $69.5 million, an increase of 70% from Adjusted EBITDA of $40.8 million during the three months ended June 30, 2013. For the six months ended June 30, 2014, our Adjusted EBITDA was $125.8 million, an increase of 54% from $81.4 million during the six months ended June 30, 2013. These oil and natural gas revenues and Adjusted EBITDA values were the best reported for any three-month and six-month period, respectively, in our Company's history. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for 2014, see "— Results of Operations" below.

On May 29, 2014, we completed an underwritten public offering of 7,500,000 shares of our common stock and received net proceeds of approximately $181.3 million. We have used the net proceeds from this offering to fund a portion of our capital expenditures, including to operate a fourth rig in the Permian Basin throughout the remainder of 2014, allowing us to operate two drilling rigs for the development of our acreage in the Eagle Ford shale and two rigs for the exploration and delineation of our acreage in the Wolfcamp and Bone Spring plays in the Permian Basin. We also have used and expect to continue to use portions of the net proceeds from the equity offering to fund targeted acquisitions of additional acreage in the Permian Basin, as well as in the Eagle Ford shale and the Haynesville shale, for our participation in additional Haynesville wells proposed by a subsidiary of Chesapeake Energy Corporation ("Chesapeake") and for other general working capital needs. Pending such uses, we repaid $180.0 million in outstanding borrowings under our third amended and restated credit agreement (the "Credit Agreement") in May 2014, which amounts may be re-borrowed in accordance with the terms of that facility.

Our 2014 drilling activity will continue to be focused on increasing our oil production and reserves in South Texas, primarily in the Eagle Ford shale play, while we expand our exploration and delineation efforts in the Permian Basin in Southeast New Mexico and West Texas. At March 31, 2014, we had two contracted drilling rigs operating on our Eagle Ford acreage in South Texas and one contracted drilling rig operating in the Permian Basin. In April 2014, we replaced the drilling rig operating in the central portion of our Eagle Ford acreage in Karnes County with a new "walking" rig. Due to a temporary contract overlap resulting from initiating drilling operations with this second "walking" rig, we moved the rig being replaced in Karnes County to Loving County, Texas in order to provide us with a second rig in the Permian Basin. As noted above, we are using a portion of the proceeds from our May 2014 equity offering to, among other items, keep this fourth rig operating full-time in the Permian Basin throughout 2014. As a result, as of August 6, 2014, we were operating four contracted drilling rigs — two in the Eagle Ford and two in the Permian Basin. Because of the timing of the addition of this fourth drilling rig in the Permian Basin and our projected drilling and completions schedule, we do not expect this rig to materially impact our anticipated 2014 oil and natural gas production or our anticipated 2014 oil and natural gas revenues. Rather, we anticipate that the addition of this second rig in the Permian Basin will start to have a material impact on our operations and financial results beginning in 2015. In addition, we have decided to further accelerate our Permian drilling program by adding at least one additional rig at the beginning of 2015.

In addition, during the first quarter of 2014, we were notified by Chesapeake of its intent to drill up to a total of 30 gross (6.3 net) Haynesville wells on our Elm Grove acreage in southern Caddo Parish, Louisiana during 2014. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. Chesapeake began actively drilling on these properties during the second quarter of 2014 and, at August 6, 2014, was operating four drilling rigs on these properties. These wells are being drilled and completed in a multi-well batch mode, and as a result, we do not expect to see significant contributions from these wells to our natural gas production until late in the third quarter and perhaps even into the fourth quarter of 2014. At August 6, 2014, we had agreed to participate in 21 gross (4.4 net) wells in progress or proposed on this acreage, with an estimated total capital commitment of $37.4 million. Of these wells, 19 gross (4.2 net) wells are currently anticipated to be completed and placed on production prior to the end of the year, with most coming on line in the fourth quarter of 2014. Should Chesapeake elect to drill all 30 gross wells on this acreage in 2014, our working interest would be equivalent to approximately 6.3 net wells at an estimated capital expenditure of approximately $50.0 million.

As a result of our determination to operate two drilling rigs in the Permian Basin for the remainder of 2014, the ongoing and anticipated Chesapeake drilling activity in the Haynesville shale and additional leasehold and seismic data acquisitions anticipated throughout the remainder of 2014, we increased our 2014 capital expenditure budget from $440.0 million to $570.0 million during the second quarter of 2014. At June 30, 2014, we had incurred $273.3 million, or approximately 48%, of this anticipated 2014 capital expenditure budget.

We had two contracted drilling rigs operating in the Permian Basin during the majority of the second quarter of 2014 — one in Loving County, Texas and the other in Lea County, New Mexico. Due to the timing of our drilling, completion and production operations, we did not complete and place on production any new Permian Basin wells during the second quarter. However, three new Permian wells were completed and began testing in mid-to-late July — the Norton Schaub #1H well in Loving County, Texas and the Pickard State 20-18-34 #1H and the Pickard State 20-18-34 #2H wells in Lea County, New Mexico. The Norton Schaub #1H well flowed 1,026 BOE per day, including 706 Bbl of oil per day and 1,922 Mcf of natural gas per day (69% oil), at 3,000 pounds per square inch ("psi") flowing surface pressure on a 22/64th inch choke during its 24-hour initial potential test in mid-July 2014. This well was completed in the upper portion of the Wolfcamp formation, the Wolfcamp "A," at approximately 10,800 feet true vertical depth. We drilled a 4,700-ft horizontal lateral in the Norton Schaub #1H and stimulated this well with 20 hydraulic fracturing stages, including approximately 200,000 Bbl of fluid and 9.8 million pounds of sand. This is our second successful test of the Wolfcamp "A" formation in our Wolf prospect area. The Norton Schaub #1H was drilled in our Wolf prospect in Loving County near and to the northwest of our original well on this prospect, the Dorothy White #1H. The Dorothy White #1H was also completed in the Wolfcamp "A" formation and has continued to exhibit strong performance since being placed on production in January 2014. At July 30, 2014, in approximately seven months on production, including its initial cleanup phase, the Dorothy White #1H well has produced 175,000 BOE, including almost 115,000 Bbl of oil (66% oil). Based on the success of these two initial wells, we intend to operate one of the two Permian Basin drilling rigs full time in the Loving County area throughout the remainder of 2014.

In the Ranger prospect area, the Pickard State 20-18-34 #1H (Second Bone Spring test) and Pickard State 20-18-34 #2H (Wolfcamp "D" test) were drilled from a single surface pad and then completed back-to-back, with the Pickard State 20-18-34 #1H being put on production first after completion. The Pickard 20-18-34 #1H was completed in the Second Bone Spring sand at approximately 9,900 feet true vertical depth. We drilled a 4,100-ft horizontal lateral in the Pickard State 20-18-34 #1H and stimulated this well with 17 hydraulic fracturing stages, including approximately 167,000 Bbl of fluid and 7.3 million pounds of sand. This well flowed 592 BOE per day, including 535 Bbl of oil per day and 340 Mcf of natural gas per day (90% oil) at 750 psi flowing surface pressure on a 22/64th inch choke during its 24-hour initial potential test in late July 2014. The Pickard State 20-18-34 #1H is our second positive test of the Second Bone Spring sand in the Ranger prospect area, and early indications are that this well may be comparable to or better than our initial Second Bone Spring well, the Ranger 33 State Com #1H, which had produced 123,000 BOE, including 113,000 Bbl of oil (91% oil), in about nine months on production at July 30, 2014. The Pickard State 20-18-34 #1H well flowed oil at higher rates and at higher flowing pressures on a comparable choke than the Ranger 33 State Com #1H. At August 6, 2014, the Pickard 20-18-34 #2H well, a Wolfcamp "D" test in the Ranger prospect area, was still in the flowback period following its completion operations. At that date, the well was flowing oil and natural gas (85% to 90% oil), but has yet to have its initial potential test.

We also had two drilling rigs operating in South Texas during the second quarter of 2014 as we continued to develop our Eagle Ford acreage. During the second quarter of 2014, we completed and began producing oil and natural gas from six gross (5.4 net) operated and three gross (0.8 net) non-operated Eagle Ford shale wells. We completed three operated Eagle Ford wells on our Northcut lease and two wells on our Martin Ranch lease in La Salle County and one well on our Lyssy lease in southern Wilson County. The three non-operated wells were completed on our Troutt lease in La Salle County. The Northcut wells began producing in mid-April, the Martin Ranch wells began producing in mid-May and the Lyssy well began producing in mid-June. As a result, these six wells did not contribute fully to our production volumes for the second quarter of 2014 or for the first half of 2014. We also participated in 13 gross (0.6 net) non-operated Haynesville shale wells completed and placed on production during the second quarter of 2014, but these wells did not include any of the 30 gross wells in progress or proposed by Chesapeake on our Elm Grove properties as described above.

At June 30, 2014, our estimated total proved oil and natural gas reserves were 57.2 million BOE, including 18.6 million Bbl of oil and 231.4 Bcf of natural gas, with a PV-10 of $826.0 million and a Standardized Measure of $723.0 million. At December 31, 2013, our estimated proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, and at June 30, 2013, our estimated proved oil and natural gas reserves were 38.9 million BOE, including 12.1 million Bbl of oil and 160.8 Bcf of natural gas. Our proved oil reserves of 18.6 million Bbl at June 30, 2014 increased 54%, as compared to 12.1 million Bbl at June 30, 2013, and 14%, as compared to 16.4 million Bbl at December 31, 2013. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

We realized a weighted average oil price of $97.92 per Bbl for the three months ended June 30, 2014, as compared to $99.77 per Bbl for the three months ended June 30, 2013. Most of our Eagle Ford oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. Oil production from our properties in the Permian Basin in Southeast New Mexico and West Texas is sold on a West Texas Intermediate oil price index less transportation costs. We realized a weighted average natural gas price of $5.69 per Mcf for the three months ended June 30, 2014, as compared to $4.38 per Mcf for the three months ended June 30, 2013. This price reflects an uplift as a result of natural gas liquids we produce with our Eagle Ford natural gas production, and we also expect to receive an uplift in the price we receive for most of our natural gas production from the Permian Basin due to natural gas liquids. Natural gas prices, excluding any uplift from natural gas liquids, were also considerably higher during the second quarter of 2014 as compared to the second quarter of 2013. Our natural gas production from the Haynesville shale is mostly dry natural gas and does not receive a price uplift as a result of natural gas liquids. See "— Results of Operations" below for more information on our oil and natural gas prices received during the second quarter of 2014.

We began 2014 with approximately 70,800 gross (44,800 net) acres in the Permian Basin in Southeast New Mexico and West Texas. Between January 1 and August 6, 2014, we acquired an additional 23,200 gross (17,200 net) acres in this area, primarily in Loving County, Texas and in Lea and Eddy Counties, New Mexico. Including these acreage acquisitions, at August 6, 2014, our total Permian Basin acreage position was approximately 94,000 gross (62,000 net) acres. We have also been actively acquiring additional Eagle Ford acreage in South Texas. Between January 1, 2014 and August 6, 2014, we acquired (or expect to acquire by the middle of August) 3,100 gross (2,900 net) acres in South Texas prospective for the Eagle Ford shale in La Salle, Karnes and southern Atascosa Counties. We plan to continue our leasing and acquisition efforts in the Permian Basin, Eagle Ford shale and Haynesville shale as opportunities are identified.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at June 30, 2014, December 31, 2013 and June 30, 2013. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale in South Texas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that would be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

	June 30, 2014	December 31, 2013	June 30, 2013
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	18,627	16,362	12,128
Natural Gas (Bcf)(4)	231.4	212.2	160.8
Total (MBOE)(5)	57,202	51,729	38,931
Estimated proved developed reserves:			
Oil (MBbl)(3)	9,917	8,258	6,591
Natural Gas (Bcf)(4)	60.0	53.5	57.8
Total (MBOE)(5)	19,917	17,168	16,221
Percent developed	34.8 %	33.2 %	41.7 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	8,711	8,104	5,537
Natural Gas (Bcf)(4)	171.4	158.7	103.0
Total (MBOE)(5)	37,285	34,561	22,710
PV-10(6) (in millions)	$826.0	$655.2	$522.3
Standardized Measure(7) (in millions)	$723.0	$578.7	$477.6

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month

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prices for the period from July 2013 through June 2014 were $96.75 per Bbl for oil and $4.104 per MMBtu for natural gas, for the period from January 2013 through December 2013 were $93.42 per Bbl for oil and $3.670 per MMBtu for natural gas and for the period from July 2012 through June 2013 were $88.13 per Bbl for oil and $3.444 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) One thousand barrels of oil.

(4) One billion cubic feet of natural gas.

(5) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(6) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at June 30, 2014, December 31, 2013 and June 30, 2013 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at June 30, 2014, December 31, 2013 and June 30, 2013 were, in millions, $103.0, $76.5 and $44.7, respectively.

(7) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

At June 30, 2014, our estimated total proved oil and natural gas reserves were 57.2 million BOE, including 18.6 million Bbl of oil and 231.4 Bcf of natural gas, with a PV-10 of $826.0 million and a Standardized Measure of $723.0 million. At December 31, 2013, our estimated proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, and at June 30, 2013, our estimated proved oil and natural gas reserves were 38.9 million BOE, including 12.1 million Bbl of oil and 160.8 Bcf of natural gas. Our proved oil reserves of 18.6 million Bbl at June 30, 2014 increased 14%, as compared to 16.4 million Bbl at December 31, 2013, and 54%, as compared to 12.1 million Bbl at June 30, 2013. During the six months ended June 30, 2014, our proved developed reserves increased 16% from 17.2 million BOE at December 31, 2013 to 19.9 million BOE at June 30, 2014. Year-over-year, our proved developed reserves increased 23% from 16.2 million BOE at June 30, 2013. At June 30, 2014, approximately 35% of our total proved reserves were proved developed reserves, 33% of our total proved reserves were oil and 67% of our total proved reserves were natural gas.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in the Annual Report.

Critical Accounting Policies

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update, or ASU, 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard also requires expanded disclosures surrounding revenue recognition and is intended to improve and converge with international standards the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2016, i.e., in our first fiscal quarter of 2017. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

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Results of Operations

Revenues

The following table summarizes our revenues and production data for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
Operating Data:				
Revenues (in thousands):[1]				
Oil	$78,492	$ 44,632	$142,166	$ 93,302
Natural gas	20,562	13,547	35,820	24,196
Total oil and natural gas revenues	99,054	58,179	177,986	117,498
Realized (loss) gain on derivatives	(2,913)	254	(4,756)	646
Unrealized (loss) gain on derivatives	(5,234)	7,526	(8,342)	2,701
Total revenues	$90,907	$ 65,959	$164,888	$ 120,845
Net Production Volumes:[1]				
Oil (MBbl)[2]	802	447	1,463	908
Natural gas (Bcf)[3]	3.6	3.1	6.1	6.2
Total oil equivalent (MBOE)[4]	1,403	963	2,475	1,944
Average daily production (BOE/d)[5]	15,424	10,582	13,673	10,739
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$94.47	$ 99.26	$94.67	$ 102.27
Oil, without realized derivatives (per Bbl)	$97.92	$ 99.77	$97.20	$ 102.78
Natural gas, with realized derivatives (per Mcf)	$5.65	$ 4.53	$5.72	$ 4.07
Natural gas, without realized derivatives (per Mcf)	$5.69	$ 4.38	$5.90	$ 3.89

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with extracted natural gas liquids are included with our natural gas revenues.

(2) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

(4) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Barrels of oil equivalent per day, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended June 30, 2014 as Compared to Three Months Ended June 30, 2013

Oil and natural gas revenues. Our oil and natural gas revenues increased by $40.9 million to $99.1 million, or an increase of 70%, for the three months ended June 30, 2014, as compared to $58.2 million for the three months ended June 30, 2013. This increase in oil and natural gas revenues includes an increase in our oil revenues of $33.9 million and an increase in our natural gas revenues of $7.0 million for the three months ended June 30, 2014, as compared to the three months ended June 30, 2013. Our oil revenues increased 76% to $78.5 million for the three months ended June 30, 2014, as compared to $44.6 million for the three months ended June 30, 2013. This increase in oil revenues reflects the increase in our oil production by 79% to 802,000 Bbl of oil in the second quarter of 2014, or 8,809 Bbl of oil per day, as compared to 447,000 Bbl of oil in the second quarter of 2013, or 4,916 Bbl of oil per day. This increase in oil production is attributable to our drilling operations in the Eagle Ford shale, as well as initial production contributions from newly drilled wells in the Permian Basin. Our natural gas revenues increased 52% to $20.6 million for the three months ended June 30, 2014, as compared to $13.5 million for the three months ended June 30, 2013. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $5.69 per Mcf realized during the second quarter of 2014, as compared to a weighted average natural gas price of $4.38 per Mcf realized during the second quarter of 2013, as well as a 17% increase in our natural gas production to 3.6 Bcf of natural gas in the second quarter of 2014, as compared to 3.1 Bcf of natural gas in the second quarter of 2013. This increase in the weighted average natural gas price was attributable to increased natural gas prices between the two periods, as well as the higher heating quality of, and the natural gas liquids extracted from, the natural gas produced primarily from our Eagle Ford shale wells, as compared to our Haynesville and Cotton Valley wells. In the second quarter of 2014, approximately 54% of the Company's natural gas production was liquids-rich natural gas, primarily from the Eagle Ford shale, as compared to 31% in the second quarter of 2013. The increase in natural gas production was primarily attributable to our drilling operations in both South Texas and the Permian Basin, as well as initial production contributions from newly drilled non-operated wells in the Haynesville shale in Northwest Louisiana during the three months ended June 30, 2014.

Realized (loss) gain on derivatives. Our realized loss on derivatives was $2.9 million for the three months ended June 30, 2014, as compared to a realized gain of $0.3 million for the three months ended June 30, 2013. For the three months ended June 30, 2014, we realized a net loss of $2.8 million and $0.2 million and a net gain of $38,000 attributable to our oil, natural gas and natural gas liquids ("NGL") derivative contracts, respectively. For the three months ended June 30, 2013, we realized a net loss of $0.2 million on our oil derivative contracts and a net gain of $0.1 million and $0.4 million on our natural gas and NGL derivative contracts, respectively. The change from a realized gain to a realized loss on our natural gas derivative contracts between the respective periods resulted from higher natural gas prices during the three months ended June 30, 2014, as compared to the three months ended June 30, 2013. We realized a loss of $0.06 per MMBtu hedged on all of our natural gas derivative contracts during the three months ended June 30, 2014, as compared to a gain of $0.05 per MMBtu hedged on all of our natural gas derivative contracts during the three months ended June 30, 2013. During the second quarter of 2014, our natural gas costless collar contracts had average floor and ceiling prices of $3.50 per MMBtu and $4.93 per MMBtu, respectively, as compared to $3.43 per MMBtu and $4.74 per MMBtu, respectively, during the second quarter of 2013. The realized loss on our oil derivative contracts during the three months ended June 30, 2014 and 2013 resulted from oil prices that were higher than the ceiling prices of several of our oil costless collar contracts. The average floor prices of our oil costless collar contracts were $87.73 per Bbl and $87.00 per Bbl as of June 30, 2014 and June 30, 2013, respectively. The average ceiling prices of our oil costless collar contracts were $99.76 per Bbl and $110.27 per Bbl as of June 30, 2014 and June 30, 2013, respectively. Our total oil and natural gas volumes hedged for the three months ended June 30, 2014 were 76% and 47% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2013.

Unrealized loss on derivatives. Our unrealized loss on derivatives was $5.2 million for the three months ended June 30, 2014, as compared to an unrealized gain of $7.5 million for the three months ended June 30, 2013. During the period from March 31, 2014 to June 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net liability of $5.9 million to a net liability of $11.1 million, resulting in an unrealized loss on derivatives of $5.2 million for the three months ended June 30, 2014. The net fair value of our open oil derivative contracts decreased $5.7 million at June 30, 2014, as compared to March 31, 2014, due to higher oil futures prices at June 30, 2014. The net fair value of our open natural gas derivative contracts increased $0.7 million at June 30, 2014, as compared to March 31, 2014, as natural gas futures prices decreased during this period. The net fair value of our open NGL derivative contracts decreased $0.2 million at June 30, 2014, as compared to March 31, 2014, due to slight increases in futures prices for certain of these commodities. During the period from March 31, 2013 to June 30, 2013, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from $(0.3) million to $7.2 million due to decreases in futures prices for these commodities, resulting in an unrealized gain on derivatives of $7.5 million for the three months ended June 30, 2013.

Six Months Ended June 30, 2014 as Compared to Six Months Ended June 30, 2013

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $60.5 million to approximately $178.0 million, or an increase of about 51%, for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. This increase in oil and natural gas revenues includes an increase in our oil revenues of $48.9 million and an increase in our natural gas revenues of $11.6 million for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. Our oil revenues increased by 52% to $142.2 million for the six months ended June 30, 2014, as compared to $93.3 million for the six months ended June 30, 2013. This increase reflects the increase in our oil production by 61% to 1,463 MBbl of oil in the six months ended June 30, 2014, or about 8,080 Bbl of oil per day, as compared to 908 MBbl of oil produced, or about 5,015 Bbl of oil per day, in the six months ended June 30, 2013. This increased oil production is primarily attributable to our drilling operations in the Eagle Ford shale, as well as initial production contributions from newly drilled wells in the Permian Basin. The increased revenues attributable to increased production were partially offset by a slightly lower oil price of $97.20 per

Bbl realized for the six months ended June 30, 2014, as compared to $102.78 per Bbl realized for the six months ended June 30, 2013. The increase in natural gas revenues resulted from a higher weighted average natural gas price of $5.90 per Mcf realized during the six months ended June 30, 2014, as compared to a weighted average natural gas price of $3.89 per Mcf realized during the six months ended June 30, 2013. This increase in the weighted average natural gas price was attributable to increased natural gas prices between the two periods, as well as the higher heating quality of, and the natural gas liquids extracted from, the natural gas produced primarily from our Eagle Ford shale wells, as compared to our Haynesville and Cotton Valley wells. In the six months ended June 30, 2014, approximately 54% of the Company’s natural gas production was liquids-rich natural gas, primarily from the Eagle Ford shale, as compared to 29% in the six months ended June 30, 2013.

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Realized (loss) gain on derivatives. We realized a loss on derivatives of approximately $4.8 million for the six months ended June 30, 2014, as compared to a gain of approximately $0.6 million for the six months ended June 30, 2013. For the six months ended June 30, 2014, we realized a net loss of approximately $3.7 million, $0.8 million and $0.3 million attributable to our oil, natural gas and NGL derivative contracts, respectively. For the six months ended June 30, 2013, we realized a net loss of approximately $0.5 million attributable to our oil derivative contracts and a net gain of approximately $0.6 million and $0.5 million attributable to our natural gas and NGL derivative contracts, respectively. The net loss realized from our derivative contracts resulted primarily from lower ceiling prices on our oil derivative contracts and higher natural gas prices during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. We realized a loss of approximately $4.36 per Bbl and $0.13 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the six months ended June 30, 2014, as compared to a loss of $0.63 per Bbl and a gain of $0.17 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the six months ended June 30, 2013. During the six months ended June 30, 2014, our natural gas costless collar contracts had average floor and ceiling prices of $3.46 per MMBtu and $4.95 per MMBtu, respectively, as compared to $3.46 per MMBtu and $4.83 per MMBtu, respectively, for the six months ended June 30, 2013. The average floor prices of our oil costless collar contracts were $87.72 per Bbl and $87.27 per Bbl as of June 30, 2014 and June 30, 2013, respectively. The average ceiling prices of our oil costless collar contracts were $99.76 per Bbl and $110.25 per Bbl as of June 30, 2014 and June 30, 2013, respectively. Our total oil and natural gas volumes hedged for the six months ended June 30, 2014 were 62% and 67% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2013.

Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $8.3 million for the six months ended June 30, 2014, as compared to an unrealized gain of approximately $2.7 million for the six months ended June 30, 2013. During the period from December 31, 2013 through June 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from a net liability of approximately $2.8 million to a net liability of approximately $11.1 million, resulting in an unrealized loss on derivatives of approximately $8.3 million for the six months ended June 30, 2014. This loss is primarily attributable to a decrease in the net fair value of our open oil contracts for the six months ended June 30, 2014. This decrease was due primarily to an increase in oil futures prices, which decreased the net fair value of our open oil contracts by approximately $7.7 million between December 31, 2013 and June 30, 2014. The net fair value of our open natural gas contracts decreased by $0.6 million during the same period. During the period from December 31, 2012 through June 30, 2013, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from $4.5 million to $7.2 million, resulting in an unrealized gain on derivatives of $2.7 million for the six months ended June 30, 2013.

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Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated:

(In thousands, except expenses per BOE)	Three Months Ended June 30, 2014 (Unaudited)	Three Months Ended June 30, 2013 (Unaudited)	Six Months Ended June 30, 2014 (Unaudited)	Six Months Ended June 30, 2013 (Unaudited)
Expenses:				
Production taxes and marketing	$9,116	$ 4,451	$15,122	$ 8,548
Lease operating	11,704	10,140	21,055	21,040
Depletion, depreciation and amortization	31,797	20,234	55,827	48,466
Accretion of asset retirement obligations	123	80	241	161
Full-cost ceiling impairment	—	—	—	21,229
General and administrative	8,100	4,149	15,319	8,751
Total expenses	60,840	39,054	107,564	108,195
Operating income	30,067	26,905	57,324	12,650
Other income (expense):				
Net loss on asset sales and inventory impairment	—	(192)	—	(192)
Interest expense	(1,616)	(1,609)	(3,012)	(2,880)
Interest and other income	409	47	447	115
Total other expense	(1,207)	(1,754)	(2,565)	(2,957)
Income before income taxes	28,860	25,151	54,759	9,693
Total income tax provision	10,634	32	20,170	78
Net income	$18,226	$ 25,119	$34,589	$ 9,615
Expenses per BOE:				
Production taxes and marketing	$6.50	$ 4.62	$6.11	$ 4.40
Lease operating	$8.34	$ 10.53	$8.51	$ 10.82
Depletion, depreciation and amortization	$22.66	$ 21.01	$22.56	$ 24.93
General and administrative	$5.77	$ 4.31	$6.19	$ 4.50

Three Months Ended June 30, 2014 as Compared to Three Months Ended June 30, 2013

Production taxes and marketing. Our production taxes and marketing expenses increased by $4.7 million to $9.1 million, or an increase of 105%, for the three months ended June 30, 2014, as compared to $4.5 million for the three months ended June 30, 2013. On a unit-of-production basis, however, our production taxes and marketing expenses increased by 41% to $6.50 per BOE for the three months ended June 30, 2014, as compared to $4.62 per BOE for the three months ended June 30, 2013, due to our increased oil and natural gas production between the respective periods. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by 70% during the three months ended June 30, 2014, as compared to the three months ended June 30, 2013. A large portion of this increase was attributable to production taxes associated with the increase in oil production and associated oil revenues during the three months ended June 30, 2014, as compared to the three months ended June 30, 2013, resulting primarily from our drilling operations in the Eagle Ford shale, as well as initial production contributions from our newly drilled wells in the Permian Basin. Oil comprised 57% of our total production volume in the second quarter of 2014, as compared to 46% in the second quarter of 2013. The increase in production taxes and marketing expenses during the second quarter of 2014, as compared to the second quarter of 2013, also reflected the higher percentage of our natural gas production from the Eagle Ford shale in Texas, where natural gas production taxes are higher than production taxes associated with Haynesville shale gas in Louisiana. We produced 48% of our total natural gas volume from the Eagle Ford in the second quarter of 2014, as compared to only 31% in the second quarter of 2013. Production taxes and marketing expenses for the three months ended June 30, 2014 also reflected some increased charges associated with non-operated natural gas processing fees in South Texas.

Lease operating expenses. Our lease operating expenses increased by $1.6 million to $11.7 million, or an increase of 15%, for the three months ended June 30, 2014, as compared to $10.1 million for the three months ended June 30, 2013. Between these respective periods, our total oil and natural gas production increased 46% to 1,403 MBOE from approximately 963 MBOE, including an increase in oil production of 79% to 802 MBbl from 447 MBbl. Our lease operating expenses per unit of production decreased 21% to $8.34 per BOE for the three months ended June 30, 2014, as compared to $10.53 per BOE for the three months ended June 30, 2013. Oil production was 57% of total production by volume in the second quarter of 2014, as compared to 46% of total production by volume in the second quarter of 2013, which would typically result in higher LOE on a per unit basis. The decrease achieved in LOE on a per unit basis results from the progress we have made in reducing our LOE during the last twelve months, which was primarily attributable to (1) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended use of flowback equipment to produce newly completed Eagle Ford wells, (2) the early use of gas lift on most of our newly completed Eagle Ford wells and (3) a decrease in salt water disposal costs on a per barrel basis, as well as continued improvement in overall operational processes, in our South Texas operations.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $11.6 million to $31.8 million, or an increase of 57%, for the three months ended June 30, 2014, as compared to the three months ended June 30, 2013. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $22.66 per BOE for the three months ended June 30, 2014, or an increase of 8%, from $21.01 per BOE for the three months ended June 30, 2013. The increase in the total depletion, depreciation and amortization expenses is attributable to the increase in our oil and natural gas production of 46% to 1,403 MBOE from 963 MBOE between the respective periods. The increase in the unit-of-production depletion, depreciation and amortization expenses is attributable to the increase in our oil production as a percentage of our total production to 57% from 46% between the respective periods and to the higher finding and development costs associated with our oil reserves as compared to our natural gas reserves on a per BOE basis.

General and administrative. Our general and administrative expenses increased by $4.0 million to $8.1 million, or an increase of 95%, for the three months ended June 30, 2014, as compared to $4.1 million for the three months ended June 30, 2013. The increase in our general and administrative expenses for the three months ended June 30, 2014 was largely attributable to additional payroll expenses associated with personnel added between the respective periods to support our increased drilling and completion operations. The remaining increase is due to an increase in stock-based compensation expense of $0.8 million to $1.8 million for the three months ended June 30, 2014, as compared to $1.0 million for the three months ended June 30, 2013. The increase in our stock-based compensation expense is attributable to the continued vesting of awards granted in 2012 and 2013, and new awards granted in 2014, as well as the increased fair value of our liability-based stock options during the three months ended June 30, 2014, resulting from an increase in the price per share of our common stock from $24.49 to $29.28 during the second quarter of 2014. Our general and administrative expenses in the second quarter of 2013 were also impacted favorably as a result of our allocating and capitalizing approximately $1.0 million of our general and administrative expenses to the permanent production facilities being constructed on certain of our Eagle Ford properties in South Texas. While our general and administrative expenses increased 95% on an absolute basis, our general and administrative expenses on a unit-of-production basis increased only 34% to $5.77 per BOE for the three months ended June 30, 2014, as compared to $4.31 per BOE for the three months ended June 30, 2013, as a result of our increased oil equivalent production between the respective periods.

Interest expense. For the three months ended June 30, 2014, we incurred total interest expense of $2.3 million. We capitalized $0.7 million of our interest expense on certain qualifying projects for the three months ended June 30, 2014 and expensed the remaining $1.6 million to operations. For the three months ended June 30, 2013, we incurred total interest expense of $2.1 million. We capitalized $0.5 million of our interest expense on certain qualifying projects for the three months ended June 30, 2013 and expensed the remaining $1.6 million to operations. The increase in total interest expense is primarily attributable to an increase in outstanding borrowings under our Credit Agreement between the comparable periods. In late May 2014, we used a portion of the net proceeds of our public equity offering to repay $180.0 million of outstanding borrowings under our Credit Agreement. At June 30, 2014, we had $150.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by approximately $362,000 to approximately $409,000 for the three months ended June 30, 2014, as compared to approximately $47,000 for the three months ended June 30, 2013. The increase in our interest and other income was due primarily to an increase in the natural gas transportation income we received from third parties during the three months ended June 30, 2014, as compared to the three months ended June 30, 2013, although on the whole, this item is an insignificant component of our overall income.

Total income tax provision. Based on our projections for the remainder of 2014, we anticipate incurring an alternative minimum tax (“AMT”) liability for the year ending December 31, 2014, the proportionate share of which is recorded as the current income tax provision of $1.5 million for the three months ended June 30, 2014. The total income tax provision of $10.6 million for the three months ended June 30, 2014 also includes $9.1 million of deferred income taxes. Our effective tax rate for the three months ended June 30, 2014 was 36.9%. Total income tax expense for the three months ended June 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. At June 30, 2013, based on our projections for the remainder of 2013, we anticipated incurring a small AMT liability for the year ending December 31, 2013, the proportionate share of which was recorded as the current income tax provision of $32,000 for the three months ended June 30, 2013. The total income tax provision for the three months ended June 30, 2013 represented only our estimate of the AMT liability attributable to the three months ended June 30, 2013. We established a valuation allowance against our net deferred tax assets at September 30, 2012 and retained a full valuation allowance of approximately $6.7 million at June 30, 2013 due to uncertainties regarding the future realization of our net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the three months ended June 30, 2013, other than the AMT liability noted above.

Six Months Ended June 30, 2014 as Compared to Six Months Ended June 30, 2013

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $6.6 million to approximately $15.1 million, or an increase of approximately 77%, for the six months ended June 30, 2014, as compared to $8.5 million for the six months ended June 30, 2013. On a unit-of-production basis, however, our production taxes and marketing expenses increased by 39% to $6.11 per BOE for the six months ended June 30, 2014, as compared to $4.40 per BOE for the six months ended June 30, 2013, due to our increased oil and natural gas production between the respective periods. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by 51% during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. A large portion of this increase was attributable to production taxes associated with the increase in oil production and associated oil revenues during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, resulting primarily from our drilling operations in the Eagle Ford shale, as well as initial production contributions from newly drilled wells in the Permian Basin. Oil comprised approximately 59% of our total production volume in the first six months of 2014, as compared to 47% in the first six months of 2013. The increase in production taxes and marketing expenses during the first six months of 2014, as compared to the first six months of 2013, also reflected the higher percentage of our natural gas production from the Eagle Ford shale in Texas, where natural gas production taxes are higher than production taxes associated with Haynesville shale gas in Louisiana. We produced 49% of our total natural gas volume from the Eagle Ford in the first six months of 2014, as compared to only 28% in the first six months of 2013. Production taxes and marketing expenses for the six months ended June 30, 2014 also reflected some increased charges associated with non-operated natural gas processing fees in South Texas.

Lease operating expenses. Our lease operating expenses remained relatively consistent at $21.1 million for the six months ended June 30, 2014, as compared to $21.0 million for the six months ended June 30, 2013. Our lease operating expenses per unit of production decreased 21% to $8.51 per BOE for the six months ended June 30, 2014, as compared to $10.82 per BOE for the six months ended June 30, 2013. During these respective periods, our total oil and natural gas production increased about 27% to 2,475 MBOE from 1,944 MBOE, including an increase of 61% in oil production to 1,463 MBbl of oil from 908 MBbl of oil, which would typically result in higher LOE. Oil production was 59% of total production by volume for the six months ended June 30, 2014, as compared to only 47% of total production by volume for the six months ended June 30, 2013. The decrease achieved in LOE on a per unit basis results from the progress we have made in reducing our LOE during the last twelve months, which was primarily attributable to (1) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended use of flowback equipment to produce newly completed Eagle Ford wells, (2) the early use of gas lift on most of our newly completed Eagle Ford wells and (3) a decrease in salt water disposal costs on a per barrel basis, as well as continued improvement in overall operational processes, in our South Texas operations.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $7.4 million to $55.8 million, or an increase of 15%, for the six months ended June 30, 2014, as compared to $48.5 million for the six months ended June 30, 2013. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $22.56 per BOE for the six months ended June 30, 2014, or a decrease of about 10%, from $24.93 per BOE for the six months ended June 30, 2013. The increase in the total depletion, depreciation and amortization expenses was attributable to the increase in our oil and natural gas production by 27% to 2,475 MBOE from 1,944 MBOE between the respective periods. The decrease in the per-unit-of-production depletion, depreciation and amortization expenses primarily resulted from significantly higher estimated total proved reserves at March 31, 2014, as compared to estimated total proved reserves at March 31, 2013. Because we use the unit-of-production method for calculating depletion, depreciation and amortization, the impact of the increased production experienced in the six months ended June 30, 2014 on our depletion, depreciation and amortization expenses, as compared to the six months ended June 30, 2013, was offset by the increase in our proved oil and natural gas reserves to 57.2 million BOE at June 30, 2014 from 38.9 million BOE at June 30, 2013.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the six months ended June 30, 2014. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $13.7 million. As a result, we recorded an impairment charge of $21.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.5 million. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the six months ended June 30, 2013. At March 31, 2013 and June 30, 2013, we retained a full valuation allowance against our net deferred tax assets, and as a result, no deferred income tax provision is reflected in our unaudited condensed consolidated statement of operations for the six months ended June 30, 2013.

General and administrative. Our general and administrative expenses increased by $6.6 million to $15.3 million, or an increase of approximately 75%, for the six months ended June 30, 2014, as compared to $8.8 million for the six months ended June 30, 2013. The increase in our general and administrative expenses was primarily attributable to additional payroll expenses associated with personnel added between the respective periods to support our increased operations. The remaining increase is largely due to an increase in stock-based compensation costs of $2.1 million to $3.6 million for the six months ended June 30, 2014, as compared to $1.5 million for the six months ended June 30, 2013. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of awards granted in 2012 and 2013, and new awards granted in 2014, as well as the increased fair value of our liability-based stock options during the six months ended June 30, 2014, resulting from an increase in the price per share of our common stock from $18.64 to $29.28 during the first six months of 2014. Our general and administrative expenses in the second quarter of 2013 were also impacted favorably as a result of our allocating and capitalizing approximately $1.0 million of our general and administrative expenses to the permanent production facilities being constructed on certain of our Eagle Ford properties in South Texas. While our general and administrative expenses increased 75% on an absolute basis, our general and administrative expenses increased by only 38% on a unit-of-production basis to $6.19 per BOE for the six months ended June 30, 2014, as compared to $4.50 per BOE for the six months ended June 30, 2013, as a result of our increased production between the respective periods.

Interest expense. For the six months ended June 30, 2014, we incurred total interest expense of approximately $4.4 million. We capitalized approximately $1.4 million of our interest expense on certain qualifying projects for the six months ended June 30, 2014 and expensed the remaining $3.0 million to operations. For the six months ended June 30, 2013, we incurred total interest expense of approximately $3.7 million. We capitalized approximately $0.8 million of our interest expense on certain qualifying projects for the six months ended June 30, 2013 and expensed the remaining $2.9 million to operations. In late May 2014, we used a portion of the net proceeds of our public equity offering to repay $180.0 million of outstanding borrowings under our Credit Agreement. At June 30, 2014, we had $150.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by approximately $332,000 to approximately $447,000 for the six months ended June 30, 2014, as compared to approximately $115,000 for the six months ended June 30, 2013. The increase in our interest and other income was due primarily to an increase in the natural gas transportation income we received from third parties during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, although on the whole, this item is an insignificant component of our overall income.

Total income tax provision. Based on our projections for the remainder of 2014, we anticipate incurring an AMT liability for the year ending December 31, 2014, the proportionate share of which is recorded as the current income tax provision of approximately $2.8 million for the six months ended June 30, 2014. The total income tax provision of approximately $20.2 million for the six months ended June 30, 2014 also includes approximately $17.4 million of deferred income taxes. Our effective tax rate for the six months ended June 30, 2014 was 36.8%. Total income tax expense for the six months ended June 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. We had a net loss for the six months ended June 30, 2013 and recorded a total income tax benefit of approximately $78,000. At June 30, 2013, based on our projections for the remainder of 2013, we anticipated incurring an AMT liability for the year ending December 31, 2013, the proportionate share of which was recorded as the current income tax provision of approximately $78,000 for the six months ended June 30, 2013. We established a valuation allowance against our net deferred tax assets at September 30, 2012 and retained a full valuation allowance through June 30, 2013 due to uncertainties regarding the future realization of our net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the six months ended June 30, 2013, other than the AMT liability noted above.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during 2014 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including additional borrowings, equity and debt financings and joint ventures, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to continue to grow our operating cash flows.

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At June 30, 2014, we had cash totaling $14.6 million, the borrowing base under our Credit Agreement was $385.0 million and we had $150.0 million of outstanding long-term borrowings and $0.6 million in outstanding letters of credit. During the three months ended June 30, 2014, the borrowings bore interest at an effective interest rate of 3.6% per annum. From July 1, 2014 through August 6, 2014, we borrowed an additional $45.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. We used the proceeds from our May 2014 equity offering to, among other items, repay $180.0 million under our Credit Agreement.
Our 2014 drilling activity will continue to be focused on increasing our oil production and reserves in South Texas, primarily in the Eagle Ford shale play, while we expand our exploration and delineation efforts in the Permian Basin in Southeast New Mexico and West Texas. At March 31, 2014, we had two contracted drilling rigs operating on our Eagle Ford acreage in South Texas and one contracted drilling rig operating in the Permian Basin. In April 2014, we replaced the drilling rig operating in the central portion of our Eagle Ford acreage in Karnes County with a new “walking” rig. Due to a temporary contract overlap resulting from initiating drilling operations with this second “walking” rig, we moved the rig being replaced in Karnes County to Loving County, Texas in order to provide us with a second rig in the Permian Basin. We are using a portion of the proceeds from our May 2014 equity offering to, among other items, keep this fourth rig operating full-time in the Permian Basin throughout 2014. As a result, as of August 6, 2014, we were operating four contracted drilling rigs — two in the Eagle Ford and two in the Permian Basin. Because of the timing of the addition of this fourth drilling rig in the Permian Basin and our projected drilling and completions schedule, we do not expect this rig to materially impact our anticipated 2014 oil and natural gas production or our anticipated 2014 oil and natural gas revenues. Rather, we anticipate that the addition of this second rig in the Permian Basin will start to have a material impact on our operations and financial results beginning in 2015. Based on the success of the first two wells on our Wolf prospect, we intend to operate one of our two Permian Basin drilling rigs full-time in the Loving County area throughout the remainder of 2014. In addition, we have decided to further accelerate our Permian drilling program by adding at least one additional rig at the beginning of 2015.
In addition, during the first quarter of 2014, we were notified by Chesapeake of its intent to drill up to a total of 30 gross (6.3 net) Haynesville wells on our Elm Grove acreage in southern Caddo Parish, Louisiana during 2014. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. At August 6, 2014, we had agreed to participate in 21 gross (4.4 net) wells in progress or proposed by Chesapeake on this acreage with an estimated total capital commitment of $37.4 million. Should Chesapeake elect to drill all 30 wells on this acreage in 2014, our working interest would be equivalent to approximately 6.3 net wells at an estimated capital expenditure of approximately $50.0 million.
Between January 1, 2014 and August 6, 2014, we acquired 23,200 gross (17,200 net) acres in the Permian Basin and acquired (or expect to acquire by the middle of August) 3,100 gross (2,900 net) acres in the Eagle Ford shale in South Texas. We plan to continue our leasing and acquisition efforts in the Permian Basin, Eagle Ford shale and Haynesville shale as opportunities are identified.
As a result of our determination to operate two drilling rigs in the Permian Basin for the remainder of 2014, the ongoing and anticipated Chesapeake drilling activity in the Haynesville shale and additional leasehold and seismic data acquisitions anticipated throughout the remainder of 2014, we increased our 2014 capital expenditure budget from $440.0 million to $570.0 million during the second quarter of 2014. At June 30, 2014, we had incurred $273.3 million, or approximately 48%, of this anticipated 2014 capital expenditure budget. We anticipate investing $570.0 million for exploration, development and acquisition efforts as follows:

	Amount (in millions)
Exploration, development drilling and completion costs	$ 470.0
Pipeline and infrastructure expenditures	20.0
Leasehold acquisition and 2-D and 3-D seismic data	80.0
Total	$ 570.0

While we have budgeted $570.0 million in capital expenditures for 2014, the amount, timing and allocation of our capital expenditures is largely discretionary and within our control. The aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities we may encounter during the remainder of 2014. If oil or natural gas prices decline or costs increase significantly, we could defer a significant portion of our anticipated capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the

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timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

As a result of our May 2014 equity offering, current availability and anticipated increases in the borrowing base under our Credit Agreement and anticipated increases in our oil and natural gas production and related revenues, excluding any possible significant acquisitions, we expect to have sufficient future borrowing capacity under our Credit Agreement and cash flows from operations to fund our capital expenditure requirements for the remainder of 2014.

We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate and could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our Credit Agreement. Although a portion of our anticipated cash flows from operations for the remainder of 2014 is expected to come from development activities on currently proved properties in the Eagle Ford shale in South Texas, these development activities may be less successful than we anticipate. Further, a portion of our anticipated cash flows from operations during the year ending December 31, 2014 is expected to come from exploration activities in the Eagle Ford shale and in the Wolfcamp and Bone Spring plays in the Permian Basin, and these exploration activities may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for the remainder of 2014 and the hedges we currently have in place.

If our exploration and development activities are less successful than we anticipate or result in less cash flows than anticipated, or should oil and natural gas prices decline substantially or our capital expenditure needs increase, we may require additional sources of capital, including through additional borrowings under our Credit Agreement (assuming availability under our borrowing base) or additional credit arrangements, the sale of assets or acreage or entering into one or more joint ventures, none of which may be available. In addition to future borrowings under our Credit Agreement, we may also seek to raise additional funds by issuing debt securities or selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public markets or otherwise. Any such sales of equity or convertible securities would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us. It is also possible that, to the extent we are not able to obtain additional sources of capital on terms acceptable to us, we may modify our capital expenditure budget for the remainder of 2014 accordingly to reduce our capital spending and rate of growth or enter into one or more joint ventures or other alternative financings.

Our cash flows for the six months ended June 30, 2014 and 2013 are presented below:

	Six Months Ended June 30,	
	2014	2013
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$113,475	$83,912
Net cash used in investing activities	(236,219)	(175,901)
Net cash provided by financing activities	131,092	94,999
Net change in cash	$8,348	$3,010
Adjusted EBITDA[1]	$125,810	$81,444

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Non-GAAP Financial Measures" below.

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $29.6 million to $113.5 million for the six months ended June 30, 2014, as compared to net cash provided by operating activities of $83.9 million for the six months ended June 30, 2013. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased by $41.5 million to $120.0 million for the six months ended June 30, 2014 from $78.5 million for the six months ended June 30, 2013. This increase is primarily attributable to the 51% increase in our oil and natural gas revenues between the respective periods. Changes in our operating assets and liabilities between June 30, 2013 and June 30, 2014 resulted in a net decrease of $11.9 million in net cash provided by operating activities for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013.

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Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by $60.3 million to $236.2 million for the six months ended June 30, 2014 from $175.9 million for the six months ended June 30, 2013. This increase in net cash used in investing activities is almost entirely attributable to the increase in cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2014 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play and our initial operated drilling activities in the Permian Basin, as well as the acquisition of additional leasehold interests in both operating areas.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $131.1 million for the six months ended June 30, 2014, as compared to net cash provided by financing activities of $95.0 million for the six months ended June 30, 2013. The net cash provided by financing activities for the six months ended June 30, 2014 was primarily attributable to the total proceeds of our May 2014 equity offering of $181.9 million and incremental borrowings under our Credit Agreement of $130.0 million, offset by the costs of the offering of $0.6 million and by the repayment of $180.0 million in borrowings during the period. The net cash provided by financing activities for the six months ended June 30, 2013 was due to incremental borrowings of $95.0 million under our Credit Agreement.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

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	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2014	2013	2014	2013
Unaudited Adjusted EBITDA Reconciliation to Net Income:				
Net income	$18,226	$25,119	$34,589	$9,615
Interest expense	1,616	1,609	3,012	2,880
Total income tax provision	10,634	32	20,170	78
Depletion, depreciation and amortization	31,797	20,234	55,827	48,466
Accretion of asset retirement obligations	123	80	241	161
Full-cost ceiling impairment	—	—	—	21,229
Unrealized loss (gain) on derivatives	5,234	(7,526)	8,342	(2,701)
Stock-based compensation expense	1,834	1,032	3,629	1,524
Net loss on asset sales and inventory impairment	—	192	—	192
Adjusted EBITDA	$69,464	$40,772	$125,810	$81,444

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2014	2013	2014	2013
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$81,530	$51,684	$113,475	$83,912
Net change in operating assets and liabilities	(15,221)	(12,553)	6,509	(5,426)
Interest expense	1,616	1,609	3,012	2,880
Current income tax provision	1,539	32	2,814	78
Adjusted EBITDA	$69,464	$40,772	$125,810	$81,444

Our Adjusted EBITDA increased by $28.7 million to $69.5 million, or an increase of 70%, for the three months ended June 30, 2014, as compared to $40.8 million for the three months ended June 30, 2013. Our Adjusted EBITDA increased by $44.4 million to $125.8 million, or an increase of 54%, for the six months ended June 30, 2014, as compared to $81.4 million for the six months ended June 30, 2013. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the three and six months ended June 30, 2014, respectively, as compared to the three and six months ended June 30, 2013, respectively.

Credit Agreement

On September 28, 2012, we entered into the Credit Agreement, which increased the maximum facility amount from $400.0 million to $500.0 million. The Credit Agreement matures December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement. Borrowings are secured by mortgages on substantially all of our proved oil and natural gas properties and by the equity interests of all of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2014, our lenders completed their review of our estimated total proved oil and natural gas reserves at December 31, 2013, and as a result, on March 12, 2014, the borrowing base under our Credit Agreement was increased to $385.0 million, and the conforming borrowing base was increased to $310.0 million. At that time, we amended the Credit Agreement to, among other things, provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2015 or (ii) concurrent with the issuance by us of senior unsecured notes in an amount greater than or equal to $10.0 million. The Credit Agreement was also amended to eliminate the current ratio covenant and to increase the debt to EBITDA ratio covenant, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, to 4.25 or less. Furthermore, the interest rate charged to us based on our outstanding level of borrowings was reduced by 0.25% across the borrowing grid as a result of this amendment. This March 2014 redetermination constituted the regularly scheduled May 1 redetermination. We may request one additional unscheduled redetermination of our borrowing base prior to the next scheduled redetermination. We expect additional increases to the borrowing base will be primarily as a result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves. We anticipate receiving such an increase with our next borrowing base redetermination during the third quarter of 2014 following the lenders' review of our proved oil and natural gas reserves at June 30, 2014.

In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

At June 30, 2014, we had $150.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. For the three months ended June 30, 2014, our outstanding borrowings bore interest at an effective interest rate of approximately 3.6% per annum. We expect to access future borrowings under our Credit Agreement to fund portions of our remaining 2014 capital expenditure requirements in excess of amounts available from our operating cash flows. From July 1, 2014 through August 6, 2014, we borrowed an additional $45.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At August 6, 2014, we had $195.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.50% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("RBC") is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 3.75% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. We include this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in our interest rate calculations and related disclosures. The Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

Subject to certain exceptions, our Credit Agreement contains various covenants that limit our ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;

- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries; and
- a change of control, as defined in the Credit Agreement.

During the second quarter of 2014, Bank of America, N.A. replaced Citibank, N.A. as a lender under the Credit Agreement. At June 30, 2014, we believe that we were in compliance with the terms of the Credit Agreement.

Off-Balance Sheet Arrangements

At June 30, 2014, we did not have any off-balance sheet arrangements.

Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2014:

	Payments Due by Period				
(In thousands)	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings, including letters of credit(1)	$150,621	$621	$150,000	$—	$—
Office lease	7,183	812	1,704	1,784	2,883
Non-operated drilling commitments(2)	30,260	30,260	—	—	—
Drilling rig contracts(3)	54,733	17,936	36,797	—	—
Asset retirement obligations	10,200	477	1,213	1,644	6,866
Gas processing and transportation agreement(4)	8,000	3,497	4,198	305	—
Geophysical and geological data(5)	4,057	4,057	—	—	—
Total contractual cash obligations	$265,054	$57,660	$193,912	$3,733	$9,749

(1) At June 30, 2014, we had $150.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. The revolving borrowings are scheduled to mature in December 2016. These amounts do not include estimated interest on the obligations because our revolving borrowings have short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods.

(2) At June 30, 2014, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and several of these wells were in progress at June 30, 2014. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $30.3 million at June 30, 2014, which we expect to incur within the next few months.

(3) We do not own or operate our own drilling rigs, but instead enter into contracts with third parties for such rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which have typically been for one year or less, although we have recently begun to enter into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that are experiencing heavy demand for drilling rigs. Should we elect to terminate a contract and if the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under our drilling rig contracts were $54.7 million at June 30, 2014.

(4) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. The undiscounted minimum commitments under this agreement totaled approximately $8.0 million at June 30, 2014.

(5) From time to time, we enter into contracts with third parties for geological and geophysical data, particularly 3-D seismic data and related studies, on certain prospects to assist in the exploration of these prospects. The undiscounted minimum commitments under these agreements totaled approximately $4.1 million at June 30, 2014, which we expect to incur within the next few months.

General Outlook and Trends

For the six months ended June 30, 2014, oil prices ranged from a low of approximately $91.66 per Bbl in early January to a high of approximately $107.26 per Bbl in mid-June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $97.20 per Bbl ($94.67 per Bbl including realized losses from oil derivatives) for our oil production for the six months ended June 30, 2014, as compared to $102.78 per Bbl ($102.27 per Bbl including realized losses from oil derivatives) for the six months ended June 30, 2013. Subsequent to June 30, 2014, oil prices have decreased, and at August 6, 2014, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $96.92 per Bbl as compared to $105.30 per Bbl at August 6, 2013.

For the six months ended June 30, 2014, natural gas prices ranged from a low of $4.01 per MMBtu in early January to a high of $6.15 per MMBtu in mid-February, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $5.90 per Mcf ($5.72 per Mcf including aggregate realized losses from natural gas and NGL derivatives) for our natural gas production for the six months ended June 30, 2014, as compared to $3.89 per Mcf ($4.07 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for the six months ended June 30, 2013. The weighted average price we received for our natural gas during the six months ended June 30, 2014 was higher than the NYMEX Henry Hub natural gas price due to the NGL volumes in the liquids-rich natural gas we produce primarily from our Eagle Ford wells. Because we report our production volumes in two streams, oil and natural gas, including dry and liquids-rich natural gas, revenues associated with extracted natural gas liquids are included with our natural gas revenues, which has the effect of increasing the weighted average natural gas price realized on a per Mcf basis. Since the 2014 high in mid-February, natural gas prices have declined, and at August 6, 2014, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $3.93 per MMBtu, as compared to $3.32 per MMBtu at August 6, 2013.

Most of our Eagle Ford shale oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. Although we realized significant uplifts to West Texas Intermediate oil prices at times during 2013, the differential between these two benchmark prices has decreased substantially since early 2013. We may not realize similar, or any, uplifts to West Texas Intermediate oil prices in future periods, which could result in a decrease in our weighted average oil price realized and associated oil revenues. Additionally, we expect oil production from our properties in the Permian Basin will be sold on a West Texas Intermediate at Midland oil price index less transportation costs.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. Should oil, natural gas or natural gas liquids prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have a material adverse effect on our business, financial condition, results of operations and reserves. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets.

As we continue to explore and develop our acreage in the Permian Basin, we may face challenges associated with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to transport, process and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure and facilities on our leases throughout the area. We believe we have successfully secured the necessary drilling services for our current Permian Basin operations. We did experience difficulties in securing timely completion, and particularly certain hydraulic fracturing services, for one well drilled recently, and may have such difficulties again in the future. We believe that maintaining reliable drilling and completion services and reducing drilling and completion costs will be essential to the successful development of our Permian Basin leasehold.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and availability under our Credit Agreement.

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves

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at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, there have been no material changes to the sources and effects of our market risk since December 31, 2013.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our anticipated future production.

We use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. At June 30, 2014, RBC, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing, Inc. (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated the credit standing of the counterparties in determining the fair value of our derivative financial instruments. See “Note 8 - Derivative Financial Instruments” to the unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2014. Such information is incorporated herein by reference.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report, we evaluated the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2014 to ensure that (i) information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2014, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II—OTHER INFORMATION

Item 1. Legal Proceedings

We are party to a number of lawsuits arising in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. For a discussion of such risks and uncertainties, please see "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2013.

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

During the quarter ended June 30, 2014, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased [1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
April 1, 2014 to April 30, 2014	8,440	$26.03	—	—
May 1, 2014 to May 31, 2014	—	—	—	—
June 1, 2014 to June 30, 2014	—	—	—	—
Total	8,440	$26.03	—	—

(1) The shares were not re-acquired pursuant to any repurchase plan or program.

Item 6. Exhibits

A list of exhibits filed herewith is contained in the Exhibit Index that immediately precedes such exhibits and is incorporated by reference herein.

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SIGNATURES

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

		MATADOR RESOURCES COMPANY
Date: August 7, 2014	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman and Chief Executive Officer
Date: August 7, 2014	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

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EXHIBIT INDEX

Exhibit Number	Description
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 formatted in XBRL (eXtensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets - Unaudited, (ii) the Condensed Consolidated Statements of Operations - Unaudited, (iii) the Condensed Consolidated Statement of Changes in Shareholders’ Equity - Unaudited, (iv) the Condensed Consolidated Statements of Cash Flows - Unaudited and (v) the Notes to Condensed Consolidated Financial Statements - Unaudited (submitted electronically herewith).

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