Vanguard Natural Resources, LLC
Form 10-Q
August 01, 2013

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, 2013	
OR	
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission File Number: 001-33756
Vanguard Natural Resources, LLC
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	61-1521161 (I.R.S. Employer Identification No.)
5847 San Felipe, Suite 3000 Houston, Texas (Address of Principal Executive Offices)	77057 (Zip Code)

(832) 327-2255
(Registrant's Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes o 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Common units outstanding on July 31, 2013: 77,497,503.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
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GLOSSARY OF TERMS

Below is a list of terms that are common to our industry and used throughout this document:

/day	= per day	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
Bcf	= billion cubic feet	MMBbls	= million barrels
BOE	= barrel of oil equivalent	MMBOE	= million barrels of oil equivalent
Btu	= British thermal unit	MMBtu	= million British thermal units
MBbls	= thousand barrels	MMcf	= million cubic feet
MBOE	= thousand barrels of oil equivalent	NGLs	= natural gas liquids

When we refer to oil, natural gas and NGLs in “equivalents,” we are doing so to compare quantities of natural gas with quantities of NGLs and oil or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which 42 gallons is equal to one Bbl of oil or one Bbl of NGLs and one Bbl of oil or one Bbl of NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

References in this report to “us,” “we,” “our,” the “Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG” or "our operating subsidiary"), VNR Holdings, LLC (“VNRH”), Vanguard Permian, LLC (“Vanguard Permian”), VNR Finance Corp. (“VNRF”), Encore Energy Partners Operating LLC ("OLLC") and Encore Clear Fork Pipeline LLC.

Forward-Looking Statements

Certain statements and information in this Quarterly Report on Form 10-Q may constitute “forward-looking statements.” Statements included in this Quarterly Report on Form 10-Q that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in Management’s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “may,” “believe,” “expect,” “intend,” “anticipate,” “estimate,” “continue,” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in the Risk Factors section of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (the “2012 Annual Report”), our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 (the "Q1 Quarterly Report") and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the Securities and Exchange Commission (the “SEC”), which are available on our website at www.vnrllc.com and through the SEC’s Electronic Data Gathering and Retrieval System at www.sec.gov.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I – FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)
(Unaudited)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenues:				
Oil, natural gas and NGLs sales	$116,737	$66,441	$213,419	$149,158
Realized gain (loss) on commodity derivative contracts	(2,588)	2,165	3,184	(1,074)
Unrealized gain on commodity derivative contracts	61,183	83,309	26,136	60,575
Total revenues	175,332	151,915	242,739	208,659
Costs and expenses:				
Production:				
Lease operating expenses	26,509	16,681	50,682	35,240
Production and other taxes	9,964	7,251	19,307	14,111
Depreciation, depletion, amortization, and accretion	42,911	20,855	81,604	42,652
Selling, general and administrative expenses	6,900	4,827	13,449	9,799
Total costs and expenses	86,284	49,614	165,042	101,802
Income from operations	89,048	102,301	77,697	106,857
Other income (expense):				
Interest expense	(15,963)	(9,830)	(31,401)	(15,159)
Realized loss on interest rate derivative contracts	(962)	(566)	(1,909)	(1,142)
Unrealized gain (loss) on interest rate derivative contracts	3,374	(2,623)	4,036	(3,044)
Gain on acquisition of oil and natural gas properties, net	5,827	14,126	5,827	13,796
Other	(23)	39	28	115
Total other income (expense)	(7,747)	1,146	(23,419)	(5,434)
Net income	$81,301	$103,447	$54,278	$101,423
Distributions to Preferred unitholders	(152)	—	(152)	—
Net income available to Common and Class B unitholders	$81,149	$103,447	$54,126	$101,423
Net income per Common and Class B units – basic	$1.14	$1.99	$0.80	$1.94
Net income per Common and Class B units – diluted	$1.14	$1.98	$0.80	$1.94
Weighted average common units outstanding:				
Common units – basic	70,798	51,611	67,601	51,839
Common units – diluted	70,798	51,781	67,601	51,892
Class B units – basic & diluted	420	420	420	420

See accompanying notes to consolidated financial statements

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VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	June 30, 2013	December 31, 2012
	(Unaudited)	
Assets		
Current assets		
Cash and cash equivalents	$24,611	$11,563
Trade accounts receivable, net	72,270	51,880
Derivative assets	41,674	46,690
Other current assets	3,957	3,858
Total current assets	142,512	113,991
Oil and natural gas properties, at cost	2,476,504	2,126,268
Accumulated depletion, amortization and impairment	(629,643)	(550,032)
Oil and natural gas properties evaluated, net – full cost method	1,846,861	1,576,236
Other assets		
Goodwill	420,955	420,955
Derivative assets	65,303	53,240
Other assets	34,117	35,712
Total assets	$2,509,748	$2,200,134
Liabilities and members’ equity		
Current liabilities		
Accounts payable:		
Trade	$5,682	$8,417
Affiliates	266	32
Accrued liabilities:		
Lease operating	14,069	7,884
Development capital	12,496	4,754
Interest	11,627	11,573
Production and other taxes	18,100	12,852
Derivative liabilities	5,378	5,366
Oil and natural gas revenue payable	12,031	8,226
Distribution payable	16,072	11,919
Other	12,022	8,479
Total current liabilities	107,743	79,502
Long-term debt	997,752	1,247,631
Derivative liabilities	4,394	11,996
Asset retirement obligations, net of current portion	70,452	60,096
Other long-term liabilities	1,345	3,445
Total liabilities	1,181,686	1,402,670
Commitments and contingencies (Note 8)		
Members’ equity		
Preferred units, 2,520,000 units issued and outstanding at June 30, 2013	60,880	—

Common units, 77,090,911 units issued and outstanding at June 30, 2013 and 58,706,282 at December 31, 2012	1,264,656	794,426
Class B units, 420,000 issued and outstanding at June 30, 2013 and December 31, 2012	2,526	3,038
Total members’ equity	1,328,062	797,464
Total liabilities and members’ equity	$2,509,748	$2,200,134

See accompanying notes to consolidated financial statements

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VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2013 AND THE YEAR ENDED DECEMBER 31, 2012
(in thousands)
(Unaudited)

	Preferred Units	Preferred Units Amount	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Total Members' Equity
Balance at December 31, 2011	—	$—	48,320	$839,714	420	$4,207	$843,921
Distributions to Common and Class B unitholders (see Note 9)	—	—	—	(151,021)	—	(1,169)	(152,190)
Issuance of Common units, net of offering costs of $1,109	—	—	12,149	321,900	—	—	321,900
Common units received in exchange for Appalachian Basin properties	—	—	(1,900)	(52,480)	—	—	(52,480)
Unit-based compensation	—	—	87	4,178	—	—	4,178
Options exercised	—	—	50	950	—	—	950
Net loss	—	—	—	(168,815)	—	—	(168,815)
Balance at December 31, 2012	—	$—	58,706	$794,426	420	$3,038	$797,464
Issuance of Common units for the acquisition of oil and natural gas properties	—	—	1,075	29,992	—	—	29,992
Issuance of Preferred units, net of offering costs of $135	2,520	60,880	—	—	—	—	60,880
Issuance of Common units, net of offering costs of $636	—	—	17,304	468,100	—	—	468,100
Distributions to Preferred unitholders (see Note 9)	—	—	—	(152)	—	—	(152)
Distributions to Common and Class B unitholders (see Note 9)	—	—	—	(83,778)	—	(512)	(84,290)
Unit-based compensation	—	—	6	1,790	—	—	1,790
Net income	—	—	—	54,278	—	—	54,278
Balance at June 30, 2013	2,520	$60,880	77,091	$1,264,656	420	$2,526	$1,328,062

See accompanying notes to consolidated financial statements

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VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
Operating activities	2013	2012
Net income	$54,278	$101,423
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	81,604	42,652
Amortization of deferred financing costs	1,909	1,405
Amortization of debt discount	121	55
Deferred taxes	(504)	(124)
Compensation related items	3,503	1,818
Amortization of premiums paid on derivative contracts	109	6,959
Amortization of value on derivative contracts acquired	15,428	—
Unrealized gains on commodity and interest rate derivative contracts, net	(30,172)	(57,531)
Gain on acquisition of oil and natural gas properties, net	(5,827)	(13,796)
Changes in operating assets and liabilities:		
Trade accounts receivable	(24,177)	4,994
Payables to affiliates	234	(1,436)
Other current assets	(783)	399
Price risk management activities, net	(93)	(5,289)
Accounts payable and oil and natural gas revenue payable	1,070	4,345
Accrued expenses and other current liabilities	22,117	11,260
Other assets	138	424
Net cash provided by operating activities	118,955	97,558
Investing activities		
Additions to property and equipment	(1,545)	(286)
Additions to oil and natural gas properties	(29,418)	(23,360)
Acquisitions of oil and natural gas properties and derivative contracts	(270,535)	(453,040)
Deposits and prepayments of oil and natural gas properties	(1,047)	(4,411)
Proceeds from the sale of leasehold interests	—	5,377
Net cash used in investing activities	(302,545)	(475,720)
Financing activities		
Proceeds from long-term debt	388,500	855,959
Repayment of long-term debt	(638,500)	(545,500)
Proceeds from preferred unit offerings, net	60,880	—
Proceeds from common unit offerings, net	468,100	137,862
Distributions to Common and Class B unitholders	(80,289)	(62,631)
Financing fees	(2,053)	(10,379)
Net cash provided by financing activities	196,638	375,311
Net increase (decrease) in cash and cash equivalents	13,048	(2,851)
Cash and cash equivalents, beginning of period	11,563	2,851
Cash and cash equivalents, end of period	$24,611	$—

Supplemental cash flow information:		
Cash paid for interest	$29,470	$7,123
Non-cash investing and financing activities:		
Asset retirement obligations, net	$9,548	$9,398
Common units issued for the acquisition of oil and gas properties	$29,992	$—
Common units received in exchange for Appalachian Basin properties	$—	$52,478

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Description of the Business:

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Arkoma Basin in Arkansas and Oklahoma;
- the Permian Basin in West Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Piceance Basin in Colorado;
- South Texas;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming;
- the Powder River Basin in Wyoming; and
- Mississippi.

We were formed in October 2006 and completed our initial public offering in 2007. Our common units are listed on the NASDAQ Global Select Market ("NASDAQ") under the symbol "VNR."

1. Summary of Significant Accounting Policies

The accompanying consolidated financial statements are unaudited and were prepared from our records. We derived the Consolidated Balance Sheet as of December 31, 2012, from the audited financial statements contained in our 2012 Annual Report. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles in the United States ("GAAP"). You should read this Quarterly Report on Form 10-Q along with our 2012 Annual Report, which contains a summary of our significant accounting policies and other disclosures. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Information for interim periods may not be indicative of our operating results for the entire year.

As of June 30, 2013, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2012 Annual Report.

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of June 30, 2013 and December 31, 2012 and for the three and six months ended June 30, 2013 and 2012 include our accounts and those of our subsidiaries. We present our financial statements in accordance with GAAP. All intercompany transactions and balances have been eliminated upon consolidation.

(b) Oil and Natural Gas Properties:

The full cost method of accounting is used to account for oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil, natural gas and NGLs reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and subject to ceiling test limitations as discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs on a quarterly basis. Specifically, costs are transferred to the amortizable base when properties are determined to have proved reserves. In addition, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory wells are determined to be unsuccessful. Additionally, the amortizable base includes estimated future development costs, dismantlement, restoration and abandonment costs net of estimated salvage values.

Capitalized costs are limited to a ceiling based on the present value of future net revenues, computed using the 12-month unweighted average of first-day-of-the-month historical price (the “12-month average price”), discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write-down capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write-downs are included in the Consolidated Statements of Operations as an impairment charge. No ceiling test impairment was required during the six months ended June 30, 2013 or 2012.

When we sell or convey interests in oil and natural gas properties, we reduce oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of oil and natural gas properties unless those sales would significantly alter the relationship between capitalized costs and proved reserves. Sales proceeds on insignificant sales are treated as an adjustment to the cost of the properties.

(c) Use of Estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in impairment tests of oil and natural gas properties and goodwill, the acquisition of oil and natural gas properties, the fair value of derivative contracts and asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

2. Acquisitions

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC Topic 805, “Business Combinations” (“ASC Topic 805”). An acquisition may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. Any such gain or any loss resulting from the impairment of goodwill is recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of the properties acquired in our acquisitions have been included in the consolidated financial statements since the closing dates of the acquisitions.

During the three months ended June 30, 2013, we completed certain acquisitions of oil and natural gas properties located in our various operating regions. The total consideration transferred for the purchase of these properties amounted to $296.3 million, in the aggregate, including cash consideration of $266.3 million and $30.0 million paid in common equity by issuing 1,075,000 VNR common units, at an agreed price of $27.65 per common unit, valued at the closing price of $27.90 at the closing date of the acquisition. During the three and six months ended June 30, 2013, our acquisitions resulted in a gain of $7.3 million and in goodwill of $1.5 million, which was immediately impaired and recorded as a loss, resulting in a net gain of $5.8 million for each period.

On December 31, 2012, we completed the acquisition of natural gas and liquids properties in the Piceance Basin in Colorado and Powder River and Wind River Basins in Wyoming, with an effective date of October 1, 2012. We completed this acquisition for an adjusted purchase price of $324.7 million, subject to post-closing adjustments to be determined. We refer to this acquisition as the "Rockies Acquisition."

On June 29, 2012, we completed the acquisition of natural gas and liquids properties in the Woodford Shale in Oklahoma and Fayetteville Shale in Arkansas of the Arkoma Basin, with an effective date of April 1, 2012. We completed this acquisition for an adjusted purchase price of $428.5 million. We refer to this acquisition as the "Arkoma Basin Acquisition."

During 2012, we completed other smaller acquisitions of oil and natural gas properties located in various operating regions. We paid, in the aggregate, approximately $24.8 million in total consideration for these properties.

During the three months ended June 30, 2012, we recognized a gain on acquisition of oil and natural gas properties of $14.1 million. During the six months ended June 30, 2012, our acquisitions resulted in a gain of $14.1 million and in goodwill of $0.3 million , which was immediately impaired and recorded as a loss, resulting in a net gain of $13.8 million for the period. For a complete description of our 2012 acquisitions, please refer to footnote 2 of our consolidated financial statements contained in our 2012 Annual Report.

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the three and six months ended June 30, 2013 and 2012 to show the effect on our consolidated results of operations as if our acquisitions completed in 2013 had occurred on January 1, 2012, and as if the Arkoma Basin Acquisition, the Rockies Acquisition and our other smaller acquisitions completed during 2012 had occurred on January 1, 2011.

The pro forma results reflect the results of combining our statement of operations with the results of operations from the oil and natural gas properties acquired during 2013 and 2012, adjusted for (1) the assumption of asset retirement obligations and accretion expense for the properties acquired, (2) depletion expense applied to the adjusted basis of the properties acquired, (3) interest expense on additional borrowings necessary to finance the acquisitions, and (4) interest expense on the Senior Notes (defined in Note 3. Long-Term Debt), including the amortization of discount on bonds payable. The impact of the issuance of 1,075,000 VNR common units as consideration for one of our 2013 acquisitions is also reflected in the pro forma results. As discussed in Note 3 of our consolidated financial statements, we used a portion of the net proceeds from the Senior Notes offering to repay all indebtedness outstanding under a second lien term loan and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility. The repayment therefore resulted in an increase in the amount available for borrowing under our Reserve-Based Credit Facility. The pro forma results assume that the increase in borrowing capacity provided us available funding for the Arkoma Basin Acquisition. The unaudited pro forma results also reflect the impact of the Unit Exchange, including the elimination of the results of operations from the properties we previously owned in the Appalachian Basin and the receipt of the 1.9 million common units received as consideration for the exchange, as if it had occurred on January 1, 2011. The net gain on acquisitions of oil and natural gas properties was excluded from the pro forma results for the three and six months ended June 30, 2013 and 2012. The pro forma information is based upon these assumptions and is not necessarily indicative of future results of operations:

	Pro forma (in thousands, except per unit data)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Total revenues	$ 178,510	$ 199,250	$ 258,714	$ 342,210
Net income	$ 76,627	$ 73,286	$ 50,855	$ 95,933
Net income per unit:				
Common & Class B units – basic and diluted	$ 1.06	$ 1.38	$ 0.74	$ 1.83

The amount of revenues and excess of revenues over direct operating expenses that were eliminated to reflect the impact of the Unit Exchange in the pro forma results presented above are as follows:

	Pro forma (in thousands)	
	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Revenues	$—	$3,267
Excess of revenues over direct operating expenses	$(18)	$(400)

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The amount of revenues and excess of revenues over direct operating expenses included in the accompanying Consolidated Statements of Operations for all of our acquisitions are shown in the table that follows. Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Arkoma Basin Acquisition				
Revenues	$16,368	$—	$28,281	$—
Excess of revenues over direct operating expenses	$13,851	$—	$23,292	$—
Rockies Acquisition				
Revenues	$15,762	$—	$32,411	$—
Excess of revenues over direct operating expenses	$10,675	$—	$22,388	$—
All other acquisitions				
Revenues	$13,242	$488	$16,385	$496
Excess of revenues over direct operating expenses	$8,891	$374	$10,698	$382

3. Long-Term Debt

Our financing arrangements consisted of the following as of the date indicated:

			Amount Outstanding	
Description	Interest Rate	Maturity Date	June 30, 2013	December 31, 2012
			(in thousands)	
Senior Secured Reserve-Based Credit Facility	Variable (1)	April 16, 2018	$450,000	$700,000
Senior Notes	7.875% (2)	April 1, 2020	550,000	550,000
			$1,000,000	$1,250,000
Unamortized discount on Senior Notes			(2,248)	(2,369)
Total long-term debt			$997,752	$1,247,631

(1) Variable interest rate was 1.95% and 2.22% at June 30, 2013 and December 31, 2012, respectively.
(2) Effective interest rate was 8.0%.

Senior Secured Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the “Credit Agreement”) provides a maximum credit facility of $1.5 billion and a borrowing base of $1.3 billion (the “Reserve-Based Credit Facility”). As of June 30, 2013, there were $450.0 million of outstanding borrowings and $848.3 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $1.7 million reduction in availability for letters of credit (discussed below).

On April 17, 2013, we entered into the Fourth Amendment to the Credit Agreement, which provided for, among others, (a) the extension of the maturity date to April 16, 2018, (b) the increase of our borrowing base from $1.2 billion to $1.3 billion and (c) increased hedging flexibility. However, under the amended Credit Agreement, we are only committed to and paying for a borrowing utilization of $1.2 billion, but we have the flexibility to request the additional $100.0 million of availability if needed in the future.

Interest rates under the Reserve-Based Credit Facility are based on Euro-Dollars (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. At June 30, 2013, the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	>25% <50%	>50% <75%	>75% <90%	>90%
Eurodollar Loans Margin	1.50 %	1.75 %	2.00 %	2.25 %	2.50 %
ABR Loans Margin	0.50 %	0.75 %	1.00 %	1.25 %	1.50 %
Commitment Fee Rate	0.50 %	0.50 %	0.375 %	0.375 %	0.375 %
Letter of Credit Fee	0.50 %	0.75 %	1.00 %	1.25 %	1.50 %

Our Reserve-Based Credit Facility contains a number of customary covenants that require us to maintain certain financial ratios, limit our ability to incur indebtedness, enter into commodity and interest rate derivatives, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of our assets. At June 30, 2013, we were in compliance with all of our debt covenants.

Our Reserve-Based Credit Facility allows us to enter into commodity price hedge positions establishing certain minimum fixed prices for anticipated future production. See Note 4. Price and Interest Rate Risk Management Activities for further discussion.

Letters of Credit

At June 30, 2013, we have unused irrevocable standby letters of credit of approximately $1.7 million, which expire on December 31, 2013. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit is provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

On April 4, 2012, we completed a public offering of $350.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the “Senior Notes”), at a public offering price of 99.274%, resulting in aggregate net proceeds of $338.7 million, after deducting original issue and underwriting discounts of $10.4 million and offering costs of $0.9 million. The discount and financing fees will be amortized over the life of the Senior Notes. Such amortization is recorded in interest expense on the Consolidated Statements of Operations. We used a portion of the net proceeds from this offering to repay all remaining indebtedness outstanding under a second lien term loan and applied the balance of the net proceeds to repay outstanding borrowings under our Reserve-Based Credit Facility.

On October 9, 2012, we completed a public offering of an additional $200.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the “Additional Senior Notes”). We received net proceeds of approximately $196.4 million from this offering, after deducting underwriting discounts of $3.5 million and offering costs of $0.1 million. The Additional Senior Notes have identical terms, other than the issue date, and constitute part of the same series as and are fungible with the Senior Notes. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

The issuers of the Senior Notes and Additional Senior Notes are VNR and our 100% owned finance subsidiary, VNRF. VNR has no independent assets or operations. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to certain customary release provisions, including: (i) upon the sale or other disposition of all or substantially all of the subsidiary's properties or assets, (ii) upon the sale or other disposition of our equity interests in the subsidiary, (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture, (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture, (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities, or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor's Rating Services and Moody's Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At June 30, 2013, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $276.6 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year, beginning on October 1, 2012. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.93750% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter. We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our Reserve-Based Credit Facility to hedge price risk associated with a portion of our oil, natural gas and NGLs production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Pricing for these derivative contracts are based on certain market indexes and prices at our primary sales points. During the first half of 2013, our derivative transactions included the following:

- Fixed-price swaps - where we will receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.
- Three-way collar contracts - which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.
- Swaption agreements - where we provide options to counterparties to extend swap contracts into subsequent years.
- Call options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a call option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put spread options - created when we purchase a long put and sell a short put simultaneously.
- Put options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a put option is used to enhance an existing

position or a position that we intend to enter into simultaneously.

- Range bonus accumulators - a structure that allows us to receive a cash payment when the daily average settlement price remains within a predefined range on each expiry date. Depending on the terms of the contract, if the settlement price is below the floor or above the ceiling on any expiry date, we may have to sell at that level. Range bonus accumulators are used to enhance an existing position or a position that we intend to enter into simultaneously.

We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our Reserve-Based Credit Facility, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Any premiums paid on derivative contracts and the fair value of derivative contracts acquired in connection with our acquisitions are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid or the contracts are assumed. Premium payments are reflected in cash flows from operating activities in our Consolidated Statements of Cash Flows. When the consideration for an acquisition is cash, the fair value of any derivative contracts acquired in the acquisition is reflected in cash flows from investing activities. Over time, as the derivative contracts settle, the differences between the cash received and the premiums paid or amortization of fair value of contracts acquired are recognized as a realized gain or loss on commodity or interest rate derivate contracts, and the cash received or paid is reflected in cash flows from operating activities in our Consolidated Statements of Cash Flows.

Under ASC Topic 815, all derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We have elected not to designate our current portfolio of derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included as unrealized gains (losses) on commodity derivative contracts or gains (losses) on interest rate derivative contracts in the accompanying Consolidated Statements of Operations. We net derivative assets and liabilities for counterparties where we have a legal right of offset.

As of June 30, 2013, we had open commodity derivative contracts covering our anticipated future production as follows:

Fixed-Price Swaps

	Gas		Oil		NGLs	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average WTI Price	Bbls	Weighted Average Fixed Price
July 1, 2013 – December 31, 2013	24,048,800	$ 4.58	1,076,400	$ 90.47	92,000	$40.30
January 1, 2014 – December 31, 2014	39,750,225	$ 4.55	1,669,875	$ 90.07	182,500	$40.30
January 1, 2015 – December 31, 2015	38,507,500	$ 4.58	438,000	$ 90.38	—	$—
January 1, 2016 – December 31, 2016	34,953,000	$ 4.67	73,200	$ 92.25	—	$—
January 1, 2017 – December 31, 2017	7,602,000	$ 4.75	—	$ —	—	$—

Swaptions and Call Options Sold

Calls were sold or options were provided to counterparties under swaption agreements to extend the swap into subsequent years as follows:

	Gas		Oil	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average Fixed Price
July 1, 2013 – December 31, 2013	—	$ —	92,000	$ 99.50
January 1, 2014 – December 31, 2014	1,642,500	$ 5.69	492,750	$ 117.22
January 1, 2015 – December 31, 2015	—	$ —	508,445	$ 105.98
January 1, 2016 – December 31, 2016	—	$ —	622,200	$ 125.00

Basis Swaps

Contract Period	Gas MMBtu	Weighted Avg. Basis Differential	Pricing Index
July 1, 2013 – December 31, 2013	460,000	$(0.32)	Rocky Mountains and NYMEX Henry Hub Basis Differential
January 1, 2014 – December 31, 2014	452,500	$(0.32)	Rocky Mountains and NYMEX Henry Hub Basis Differential

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Contract Period	Oil Bbls	Weighted Avg. Basis Differential ($/Bbl)	Pricing Index
July 1, 2013 – December 31, 2013	294,400	$(0.84)	WTI Midland and WTI Cushing Basis Differential
	165,600	$(1.05)	West Texas Sour and WTI Cushing Basis Differential
	42,000	$9.60	Light Louisiana Sweet Crude and WTI Basis Differential
January 1, 2014 – December 31, 2014	584,000	$(0.84)	WTI Midland and WTI Cushing Basis Differential
	328,500	$(1.05)	West Texas Sour and WTI Cushing Basis Differential
	182,500	$(3.95)	Light Louisiana Sweet Crude and Brent Basis Differential
January 1, 2015 – December 31, 2015	365,000	$(0.90)	WTI Midland and WTI Cushing Basis Differential

Collars

Contract Period	Oil Bbls	Floor	Ceiling
July 1, 2013 – December 31, 2013	41,400	$88.89	$102.36
January 1, 2014 – December 31, 2014	12,000	$100.00	$116.20

Three-Way Collars

Contract Period	Oil Bbls	Floor	Ceiling	Put Sold
July 1, 2013 – December 31, 2013	598,000	$93.85	$101.67	$72.19
January 1, 2014 – December 31, 2014	1,313,850	$93.47	$101.26	$72.57
January 1, 2015 – December 31, 2015	924,055	$92.10	$101.55	$72.04
January 1, 2016 – December 31, 2016	549,000	$90.00	$95.00	$70.00

Put Options Sold

Contract Period	Oil Bbls	Put Sold ($/Bbl)
July 1, 2013 – December 31, 2013	404,800	$65.34
January 1, 2015 – December 31, 2015	438,000	$70.83
January 1, 2016 – December 31, 2016	73,200	$75.00

Put Spread Options

Contract Period	Oil Bbls	Floor	Put Sold
January 1, 2015 – December 31, 2015	255,500	$100.00	$75.00

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Range Bonus Accumulators

Contract Period	Oil Bbls	Bonus	Range Ceiling	Range Floor
July 1, 2013 – December 31, 2013	368,000	$3.88	$104.15	$72.63
January 1, 2014 – December 31, 2014	912,500	$4.94	$103.20	$70.50

Interest Rate Swaps

As of June 30, 2013, we had open interest rate derivative contracts as follows (in thousands):

Period	Notional Amount	Fixed Libor Rates	
July 1, 2013 to December 10, 2016	$ 20,000	2.17	%
July 1, 2013 to October 31, 2016	$ 40,000	1.65	%
July 1, 2013 to August 5, 2015 (1)	$ 30,000	2.25	%
July 1, 2013 to August 6, 2016	$ 25,000	1.80	%
July 1, 2013 to October 31, 2016	$ 20,000	1.78	%
July 1, 2013 to September 23, 2016	$ 75,000	1.15	%
July 1, 2013 to March 7, 2016	$ 75,000	1.08	%
July 1, 2013 to September 7, 2016	$ 25,000	1.25	%
July 1, 2013 to December 10, 2015 (2)	$ 50,000	0.21	%
Total	$ 360,000		

(1) The counterparty has the option to extend the termination date of this contract at 2.25% to August 5, 2018.
(2) The counterparty has the option to require Vanguard to pay a fixed rate of 0.91% from December 10, 2015 to December 10, 2017.

Balance Sheet Presentation

Our commodity derivatives and interest rate swap derivatives are presented on a net basis in “derivative assets” and “derivative liabilities” on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets for the periods indicated (in thousands):

	June 30, 2013		
Offsetting Derivative Assets:	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$141,982	$(35,289)	$106,693
Interest rate derivative contracts	284	—	284
Total derivative instruments	$142,266	$(35,289)	$106,977
Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets

Commodity price derivative contracts	$(38,252)	$35,289	$(2,963)
Interest rate derivative contracts	(6,809)	—	(6,809)
Total derivative instruments	$(45,061)	$35,289	$(9,772)

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Offsetting Derivative Assets:	December 31, 2012 Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$134,905	$(35,001)	$99,904
Interest rate derivative contracts	132	(106)	26
Total derivative instruments	$135,037	$(35,107)	$99,930

Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$(41,775)	$35,001	$(6,774)
Interest rate derivative contracts	(10,694)	106	(10,588)
Total derivative instruments	$(52,469)	$35,107	$(17,362)

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Our counterparties are participants in our Reserve-Based Credit Facility (See Note 3. Long-Term Debt for further discussion), which is secured by our oil and natural gas properties; therefore, we are not required to post any collateral. The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $142.3 million at June 30, 2013.

We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments only with counterparties that are also lenders in our Reserve-Based Credit Facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives, and therefore the risk of such loss is partially mitigated as of June 30, 2013.

Gain (Loss) on Derivative Contracts

Gains and losses on derivative contracts are reported on the accompanying Consolidated Statements of Operations in “realized or unrealized gain (loss) on commodity derivative contracts” and “realized or unrealized gain (loss) on interest rate derivative contracts.” Realized gains (losses) represent amounts related to the settlement of derivative instruments, offset by the amortization of premiums paid and the amortization of the value on derivative contracts acquired. Unrealized gains (losses) represent the change in fair value of the derivative instruments to be settled in the future and are non-cash items which fluctuate in value as commodity prices and interest rates change. The following presents our reported gains and losses on derivative instruments (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Realized gains (losses):				
Commodity derivatives	$(2,588)	$2,165	$3,184	$(1,074)
Interest rate swaps	(962)	(566)	(1,909)	(1,142)
	$(3,550)	$1,599	$1,275	$(2,216)
Unrealized gains (losses):				
Commodity derivatives	$61,183	$83,309	$26,136	$60,575

Interest rate swaps	3,374	(2,623)	4,036	(3,044)
	$64,557	$80,686	$30,172	$57,531
Net gains (losses):				
Commodity derivatives	$58,595	$85,474	$29,320	$59,501
Interest rate swaps	2,412	(3,189)	2,127	(4,186)
	$61,007	$82,285	$31,447	$55,315

5. Fair Value Measurements

We estimate the fair values of financial and non-financial assets and liabilities under ASC Topic 820 “Fair Value Measurements and Disclosures” (“ASC Topic 820”). ASC Topic 820 provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, recognition of asset retirement obligations and to long-lived assets written down to fair value when they are impaired. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. ASC Topic 820 applies to assets and liabilities carried at fair value on the Consolidated Balance Sheets, as well as to supplemental information about the fair values of financial instruments not carried at fair value.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis, which includes our commodity and interest rate derivatives contracts, and on a nonrecurring basis, which includes goodwill, acquisitions of oil and natural gas properties and other intangible assets. ASC Topic 820 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction.

ASC Topic 820 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the “levels” described below. The hierarchy is based on the reliability of the inputs used in estimating fair value and requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The framework for fair value measurement assumes that transparent “observable” (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as the lowest) of significant input to the fair value estimation process.

The standard describes three levels of inputs that may be used to measure fair value:

Level 1	Quoted prices for identical instruments in active markets.
Level 2	Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
Level 3	Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used.

As required by ASC Topic 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Financing arrangements. The carrying amounts of our bank borrowings outstanding approximate fair value because our current borrowing rates do not materially differ from market rates for similar bank borrowings. We consider this fair value estimate as a Level 2 input. The carrying amounts of our Senior Notes approximate fair value because they approximate the amounts for which the Senior Notes traded in the secondary market at June 30, 2013. We consider this fair value estimate as a Level 1 input.

Derivative instruments. Our commodity derivative instruments consist of fixed-price swaps, basis swaps, swaptions, call options sold, put spread options, put options sold, collars, three-way collars and range bonus accumulators. We account for our commodity derivatives and interest rate derivatives at fair value on a recurring basis. We estimate the fair values of the fixed-price swaps, basis-swaps and swaptions based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option value of the contract floors, ceilings, collars and three-way collars using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. We consider the fair value estimate for these derivative instruments as Level 2 input. We estimate the value of the range bonus accumulators using an option pricing model for both Asian Range Digital options and Asian Put options that takes into account market volatility, market prices and contract parameters. Range bonus accumulators are complex in structure requiring sophisticated valuation methods, and greater subjectivity. As such, range bonus accumulators valuation may include inputs and assumptions that are less observable or require greater estimation, thereby resulting in valuations with less certainty. We consider the fair value estimate for range bonus accumulators as Level 3 input.

Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Management validates the data provided by third parties by understanding the pricing models used, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to our commodity derivatives and interest rate derivatives.

Financial assets and financial liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	June 30, 2013			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$—	$105,321	$1,372	$106,693
Interest rate derivative contracts	—	284	—	284
Total derivative instruments	$—	$105,605	$1,372	$106,977
Liabilities:				
Commodity price derivative contracts	$—	$(2,963)	$—	$(2,963)
Interest rate derivative contracts	—	(6,809)	—	(6,809)
Total derivative instruments	$—	$(9,772)	$—	$(9,772)

	December 31, 2012			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$—	$99,904	$—	$99,904
Interest rate derivative contracts	—	26	—	26
Total derivative instruments	$—	$99,930	$—	$99,930
Liabilities:				

Commodity price derivative contracts	$—	$(6,276)	$(498)	$(6,774)
Interest rate derivative contracts	—	(10,588)	—	(10,588)
Total derivative instruments	$—	$(16,864)	$(498)	$(17,362)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Unobservable Inputs (Level 3) (in thousands)
Unobservable inputs at January 1, 2013	$(498)
Total gains	1,525
Settlements	345
Unobservable inputs at June 30, 2013	$1,372
Change in unrealized gains included in earnings related to derivatives still held as of June 30, 2013	$1,870

During periods of market disruption, including periods of volatile oil and natural gas prices, there may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments, other than the range bonus accumulators, may fall to Level 3 and thus require more subjectivity and management judgment. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

We apply the provisions of ASC Topic 350 “Intangibles-Goodwill and Other.” Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is assessed for impairment annually on October 1 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level, which represents our oil and natural gas operations in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. We utilize a market approach to determine the fair value of our reporting unit. Any sharp prolonged decreases in the prices of oil and natural gas or any significant negative reserve adjustments from the October 1, 2012 assessment could change our estimates of the fair value of our reporting unit and could result in an impairment charge.

Our nonfinancial assets and liabilities that are initially measured at fair value are comprised primarily of assets acquired in business combinations and asset retirement costs and obligations. These assets and liabilities are recorded at fair value when acquired/incurred but not re-measured at fair value in subsequent periods. We classify such initial measurements as Level 3 since certain significant unobservable inputs are utilized in their determination. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 6, in accordance with ASC Topic 410-20 "Asset Retirement Obligations." During the six months ended June 30, 2013 and 2012, in connection with new wells drilled and wells acquired during the period, we incurred and recorded asset retirement obligations totaling $10.2 million and $9.7 million, respectively, at fair value. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate ranging between 4.8% and 5.3%; and (4) the average inflation factor (2.5%). These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

6. Asset Retirement Obligations

The asset retirement obligations as of June 30, reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for six months ended June 30, were as follows (in thousands):

	2013	2012
Asset retirement obligations at January 1,	$63,114	$35,921
Liabilities added during the current period	10,236	9,733
Accretion expense	1,299	541
Retirements	(307)	(335)
Change in estimate	(381)	—
Total asset retirement obligation at June 30,	73,961	45,860
Less: current obligations	(3,509)	(2,067)
Long-term asset retirement obligation at June 30,	$70,452	$43,793

7. Related Party Transactions

We previously owned properties and oil and natural gas reserves in the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee (the “Appalachian Basin”). On February 21, 2012, we and our 100% owned subsidiary, VNG, entered into a Unit Exchange Agreement with Majeed S. Nami Personal Endowment Trust and Majeed S. Nami Irrevocable Trust (collectively, the “Nami Parties”) to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC, which entities controlled all of our ownership interests in oil and natural gas properties in the Appalachian Basin, in exchange for 1.9 million of our common units valued at the closing price of our common units of $27.62 per unit at March 30, 2012, or $52.5 million, with an effective date of January 1, 2012 (the “Unit Exchange”). The Nami Parties are controlled by or affiliated with Majeed S. Nami who was a founding unitholder when the Company went public in October of 2007. We completed this transaction on March 30, 2012 for non-cash consideration of $52.5 million, which was offset by post-closing adjustments of $1.4 million. This transaction was accounted for as a reduction to the full cost pool and no gain or loss was recognized because the assets transferred were not a significant portion of the full cost pool.

Prior to the completion of the Unit Exchange, we relied on Vinland Energy Eastern, LLC (“Vinland”) to execute our drilling program, operate our wells and gather our natural gas in the Appalachian Basin. We reimbursed Vinland $60.00 per well per month (in addition to normal third party operating costs) for operating our oil and natural gas properties in the Appalachian Basin under a Management Services Agreement (“MSA”) which costs were reflected in our lease operating expenses. Under a Gathering and Compression Agreement (“GCA”), Vinland received a $0.25 per Mcf transportation fee on existing wells drilled prior to December 31, 2006 and $0.55 per Mcf transportation fee on any new wells drilled after December 31, 2006 within the area of mutual interest or “AMI.” In June 2010, we began discussions with Vinland regarding an amendment to the GCA to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $0.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and jointly operated on this basis, however, no formal agreement between us and Vinland was signed. Under the GCA, the transportation fee that we paid to Vinland only encompassed transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets applied. These transportation fees were outlined in the GCA and are reflected in our lease operating expenses. Costs incurred under the MSA and GCA were $0.6 million and $0.4 million, respectively, for the three and six months ended June 30, 2012. As a result of the Unit Exchange, the MSA and GCA were terminated, and thus no costs were incurred under the MSA or GCA during the three and six months ended June 30, 2013.

8. Commitments and Contingencies

Transportation Demand Charges

On December 31, 2012 and effective with the acquisition of properties from the Rockies Acquisition, we assumed contracts that provide firm transportation capacity on pipeline systems. The remaining terms on these contracts range from one to seven years and require us to pay transportation demand charges regardless of the amount of pipeline capacity we utilize.

The values in the table below represent gross future minimum transportation demand charges we are obligated to pay as of June 30, 2013. However, our financial statements will reflect our proportionate share of the charges based on our working interest and net revenue interest, which will vary from property to property.

	(in thousands)
July 1, 2013 - December 31, 2013	$3,968
2014	5,756
2015	5,256
2016	4,797
2017	4,146
Thereafter	8,636
Total	$32,559

Legal Proceedings

We are defendants in legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flow. We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

We were a party to litigation related to the ENP Merger ("ENP Litigation") as discussed in Part II—Item 8—Financial Statements Supplementary Data in our 2012 Annual Report. On July 22, 2013, the ENP Litigation was dismissed. Please see Part II—Item 1—Legal Proceedings in this Quarterly Report for a detailed discussion on the developments of the ENP Litigation.

9. Preferred Units, Common Units and Net Income per Common Unit

Basic net income per common unit is computed in accordance with ASC Topic 260 “Earnings Per Share” (“ASC Topic 260”) by dividing net income available to common and Class B unitholders by the weighted average number of units outstanding during the period. Diluted net income per common unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. As of June 30, 2013, we had three classes of units outstanding: (i) units representing limited liability company interests (“common units”) listed on the NASDAQ under the symbol VNR, (ii) Class B units, granted to executive officers and an employee and (iii) Series A Cumulative Redeemable Perpetual Preferred Units representing preferred equity company interests ("Series A Preferred Units") listed on the NASDAQ under the symbol VNRAP as discussed in Note 11. Shelf Registration Statements. The Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic net income per unit. Series A Preferred Units have no participation rights and accordingly are excluded from the computation of basic net income per unit.

For the three and six months ended June 30, 2013, the 561,934 phantom units granted to officers, board members and employees from 2010 to date under the VNR LTIP have been excluded in the computation of net income per common unit as they had no dilutive effect. Of the 561,934 phantom units granted to date, 127,500 of them were granted to officers prior to June 30, 2012 and have been included in the computation of net income per common unit for the three months ended June 30, 2012 as they had a dilutive effect and have been excluded for the six months ended June 30, 2012 as they had no dilutive effect. For the three and six months ended June 30, 2012, the 175,000 options previously granted to officers under the Vanguard Natural Resources, LLC Long-Term Incentive Plan (“VNR LTIP”) have been included in the computation of diluted earnings per common unit as 48,852 and 52,359 additional common units, respectively, that would have been issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period. All options were exercised by the officers during the third and fourth quarter of 2012.

In accordance with ASC Topic 260, dual presentation of basic and diluted net income per common unit has been presented in the Consolidated Statements of Operations for the three and six months ended June 30, 2013 and 2012 including each class of units issued and outstanding during the respective periods: common units and Class B units. Net income available to common unitholders per unit is allocated to the common units and the Class B units on an equal basis.

The Series A Preferred Units rank senior to our common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up. The Series A Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units, at our option, in connection with a change of control. At any time on or after June 15, 2023, we may redeem the Series A Preferred Units, in whole or in part, out of amounts legally available therefor, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. We may also redeem the Series A Preferred Units in the event of a change of control. Holders of Series A Preferred Units will have no voting rights except for limited voting rights if we fail to pay dividends for eighteen or more monthly periods (whether or not consecutive) and in certain other limited circumstances or as required by law.

Distributions Declared

Distributions on the Series A Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our board of directors. We will pay cumulative distributions in cash on the Series A Preferred Units on a monthly basis at a monthly rate of $0.1641 per preferred unit, or 7.875% of the liquidation preference, per year. The initial prorated monthly distribution of $0.1422 on the Series A Preferred Units was paid on July 15, 2013. For the six months ended June 30, 2013, we accrued $0.2 million of preferred dividends attributable to the partial month from the date of offering, June 19, 2013 through the period ended June 30, 2013. On July 18, 2013, our board of directors declared a cash distribution for the Series A Preferred Units. See Note 12. Subsequent Events for further discussion.

The following table shows the amount per unit, declared date, record date and payment date of the cash distributions we paid on each of our common units for each period presented. Future distributions are at the discretion of our board of directors and will depend on business conditions, earnings, our cash requirements and other relevant factors.

On August 2, 2012, we announced a change in the payment of our distributions from quarterly to monthly commencing with the July 2012 distribution. On July 18, 2013, our board of directors declared a cash distribution on the common units attributable to the month of June 2013. See Note 12. Subsequent Events for further discussion.

Distribution	Cash Distributions Per Unit	Declared Date	Record Date	Payment Date
2013				
Second Quarter				
May	$0.2050	June 20, 2013	July 1, 2013	July 15, 2013
April	$0.2050	April 30, 2013	June 3, 2013	June 14, 2013
First Quarter				
March	$0.2025	April 19, 2013	May 1, 2013	May 15, 2013
February	$0.2025	March 21, 2013	April 1, 2013	April 12, 2013
January	$0.2025	February 18, 2013	March 1, 2013	March 15, 2013
2012				
Fourth Quarter				
December	$0.2025	January 25, 2013	February 4, 2013	February 14, 2013
November	$0.2025	December 19, 2012	January 2, 2013	January 14, 2013
October	$0.2025	November 16, 2012	December 3, 2012	December 14, 2012
Third Quarter				
September	$0.20	October 18, 2012	November 1, 2012	November 14, 2012
August	$0.20	September 17, 2012	October 1, 2012	October 15, 2012

July	$0.20	August 20, 2012	September 4, 2012	September 14, 2012
Second Quarter	$0.60	July 23, 2012	August 7, 2012	August 14, 2012
First Quarter	$0.5925	April 24, 2012	May 8, 2012	May 15, 2012
2011				
Fourth Quarter	$0.5875	January 18, 2012	February 7, 2012	February 14, 2012

10. Unit-Based Compensation

Executive Employment Agreements

In June and July 2013, we and VNRH entered into new amended and restated executive employment agreements (the "Amended Agreements") with each of our three executive officers, Messrs. Smith, Robert and Pence. The Amended Agreements were effective January 1, 2013 and the initial term of the Amended Agreements ends on January 1, 2016, with a subsequent twelve month term extension automatically commencing on January 1, 2016 and each successive January 1 thereafter, provided that neither VNRH nor the executives deliver a timely non-renewal notice prior to a term expiration date.

The Amended Agreements provide for an annual base salary and eligibility to receive an annual performance-based cash bonus award. The annual bonus will be calculated based upon three Company performance components: absolute target distribution growth, adjusted EBITDA growth, and relative unit performance to peer group, as well as a fourth component determined solely in the discretion of our board of directors. Each of the four components will be weighted equally in calculating the respective executive officer's annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two (2) times the executive's respective annual base salary. As of June 30, 2013, an accrued liability was recognized and compensation expense of $0.9 million was recorded related to these arrangements, which was classified in the selling, general and administrative expenses line item in the Consolidated Statement of Operations.

In the event of the Company's Change in Control, as defined in the VNR LTIP, the executives are entitled to certain change in control payments and benefits, consisting of: (i) an amount equal to two (2) times their then-current base salary and annual bonus and (ii) accelerated vesting of any outstanding restricted units, phantom units, or any other awards granted under the VNR LTIP held by the executives at the time of the change of control, with any settlement of these awards being made according to the terms of the VNR LTIP and the applicable individual award agreement.

The executives are entitled to severance payments and benefits upon certain qualifying terminations. Upon a termination by VNRH without "Cause" (as such term is defined in the Amended Agreements) or termination by either executive for "Good Reason" (as such term is defined in the Amended Agreements), the executive is entitled to (i) an amount equal to three (3) times the executive's then-current base salary and (ii) accelerated vesting of any outstanding restricted units, phantom units, or any other awards granted under the VNR LTIP held by the executives at the time of such termination, with any settlement of these awards being made according to the terms of the VNR LTIP. Upon an executive's termination by "Disability" (as such term is defined in the Amended Agreements) or death, the executive is entitled to (a) an amount equal to one times the executive's then-current base salary and (b) accelerated vesting of any outstanding restricted units, phantom units, or any other awards granted under the VNR LTIP held by the executives at the time of such termination, with any settlement of these awards being made according to the terms of the VNR LTIP. As a condition to receiving any of the severance payments and benefits heretofore described, the terminated executive (or his legal representative, as applicable) must execute and not revoke a customary severance and release agreement, including a waiver of all claims.

The Amended Agreements also provide that the executives are eligible to participate in the benefit programs generally available to senior executives of VNRH. The Amended Agreements also contain standard non-competition, non-solicitation and confidentiality provisions.

Restricted and Phantom Units

Under the Amended Agreements, the executives are also eligible to receive annual equity-based compensation awards, consisting of restricted units and/or phantom units granted under the VNR LTIP. Each of the executives are eligible to receive annual equity-based compensation awards having an aggregate fair market value equal to the executive's then-current annual base salary times a set multiplier, which such multiplier is five (5) times in the case of Mr. Smith, three and a half (3.5) times in the case of Mr. Robert, and two and three-quarters (2.75) in the case of Mr. Pence.

The restricted units are subject to a three-year vesting period. One-third of the aggregate number of the units vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. The restricted units include a tandem grant of distribution equivalent rights ("DERs"), which entitle the executives to receive the value of any dividends made by us on our units generally with respect to the number of restricted units that the executives received pursuant to the grant. In the event the executive is terminated without "Cause", or the executive resigns for "Good Reason", or the executive is terminated due to his death or Disability, all unvested outstanding restricted units shall receive accelerated vesting. If the executive is terminated for Cause, all unvested restricted units are forfeited. Upon the occurrence of a Change of Control, all unvested outstanding restricted units shall receive accelerated vesting.

The phantom units are also subject to a three-year vesting period. One-third of the aggregate number of the units vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. The phantom units include a tandem grant of DERs, which entitle the executives to receive the value of any dividends made by the Company on its units generally with respect to the number of phantom units that the executives received pursuant to the grant. In the event the executive is terminated without Cause, or the executive resigns for Good Reason, or the executive is terminated due to his death or Disability, all unvested outstanding phantom units shall receive accelerated vesting. If the executive is terminated for Cause, all unvested restricted units are forfeited. Upon the occurrence of a Change of Control, all unvested outstanding restricted units shall receive accelerated vesting.

The restricted units and the phantom units are subject to all the terms and conditions of the VNR LTIP as well as the individual award agreements which govern the awards. Neither the restricted units nor the phantom units are transferable, other than by will or the laws of descent and distribution. The Company shall withhold from the settlement or payment of the awards, as applicable, any amounts or units necessary to satisfy the Company's withholding obligations.

On August 1, 2012, three of our executives were granted a total of 390,000 phantom units. These phantom unit grants were made under the VNR LTIP and are subject to vesting in five equal annual installments, with the first vesting date being May 18, 2013, and each subsequent vesting date occurring on each annual anniversary of the first vesting date. During the six months ended June 30, 2013, our four independent board members were granted a total of 18,684 phantom units which will vest one year from the date of grant and VNR employees were granted a total of 68,504 phantom units. The phantom units are accompanied by dividend equivalent rights, which entitle the board members and VNR employees to receive the value of any distributions made by us on our units generally with respect to the number of phantom shares that the board members and the VNR employees received pursuant to these grants.

As of June 30, 2013, an accrued liability of $3.6 million has been recorded related to phantom units granted to executive officers, board members and employees and non-cash unit-based compensation expense of $0.7 million and $0.09 million has been recognized in the selling, general and administrative expense line item in the Consolidated Statements of Operations for three months ended June 30, 2013 and 2012, respectively, and $1.7 million and $0.2 million for the six months ended June 30, 2013 and 2012, respectively.

Non-Vested Restricted Unit Grants

Historically, we have granted restricted common units to employees as partial consideration for services to be performed and have accounted for these grants under ASC Topic 718, "Compensation-Stock Compensation." The fair value of restricted units issued is determined based on the fair market value of common units on the date of the grant. This value is amortized over the vesting period as referenced above. A summary of the status of the non-vested units as of June 30, 2013 is presented below:

	Number of Non-vested Restricted Units		Weighted Average Grant Date Fair Value
Non-vested restricted units at December 31, 2012	289,813		$27.97
Forfeited	(5,428	)	$29.09
Vested	(105,490	)	$27.31
Non-vested restricted units at June 30, 2013	178,895		$28.33

At June 30, 2013, there was approximately $4.1 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.1 years. Our

Consolidated Statements of Operations reflect non-cash compensation of $1.8 million and $0.9 million in the Selling, general and administrative expenses line item for the three months ended June 30, 2013 and 2012, respectively, and $3.5 million and $1.8 million for the six months ended June 30, 2013 and 2012, respectively.

11. Shelf Registration Statements

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million (the “2009 Shelf Registration Statement”) of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. The 2009 Shelf Registration Statement expired in August 2012. In July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million (the “2010 Shelf Registration Statement”) of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. The 2010 Shelf Registration Statement expired in July 2013.

In January 2012, we filed a registration statement (the “2012 Shelf Registration Statement”) with the SEC, which registered offerings of approximately 3.1 million common units held by certain selling unitholders. By means of the same registration statement, we also registered an indeterminate amount of common units, debt securities and guarantees of debt securities, which may be offered by us. In the future, we may issue additional debt and equity securities pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. On June 12, 2013, we filed a post-effective amendment to the 2012 Shelf Registration Statement with the SEC, which registered an indeterminate amount of Series A Cumulative Redeemable Perpetual Preferred Units representing preferred equity interests in the Company.

Net proceeds, terms and pricing of each offering of securities issued under the 2012 Shelf Registration Statement are determined at the time of such offerings. The 2012 Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the 2012 Shelf Registration Statement for the purpose of issuing, from time to time, any combination of debt securities, common units or preferred units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.
In August 2010, we entered into an Equity Distribution Program Distribution Agreement (the “2010 Distribution Agreement”) relating to our common units having an aggregate offering price of up to $60.0 million. Sales made pursuant to the 2010 Distribution Agreement were made through a prospectus supplement to our 2009 Shelf Registration Statement. Total net proceeds received under the 2010 Distribution Agreement through the expiration of the 2009 Shelf Registration Statement in August 2012 were approximately $6.3 million, after commissions, from the sales of 240,111 common units.

On September 9, 2011, we entered into an amended and restated Equity Distribution Program Distribution Agreement (the “2011 Distribution Agreement”) which extended, for an additional three years, the existing agreement with our sales agent to act as our exclusive distribution agent with respect to the issuance and sale of our common units up to an aggregate gross sales price of $200.0 million. Of the $200.0 million common units provided for under the 2011 Distribution Agreement, approximately $4.0 million of our common units were issued and sold under a prospectus supplement to our 2009 Shelf Registration Statement, which expired in August 2012. The remaining $196.0 million of the common units may be offered pursuant to a new prospectus supplement to the 2012 Shelf Registration Statement. Total net proceeds received under the 2011 Distribution Agreement during the six months ended June 30, 2013, were approximately $31.5 million, after commissions, from the sales of 1,103,499 common units.

Equity Offerings

Common Units

On February 5, 2013, we completed a public offering of 9,200,000 of our common units at a price of $27.85 per unit, which includes 1,200,000 common units purchased pursuant to the underwriters' over-allotment option. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $246.1 million from this offering, after deducting underwriting discounts of $10.0 million and offering costs of $0.1 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

On June 4, 2013, we completed a public offering of 7,000,000 of our common units at a price of $28.35 per unit. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $190.9 million from this offering, after deducting underwriting discounts of $7.4 million and offering costs of $0.1 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility. In July 2013, we received additional proceeds of $8.9 million from the sale of an additional 325,000 of our common units that were purchased by the underwriters to cover over-allotments. See Note 12. Subsequent Events for further discussion.

Preferred Units

On June 19, 2013, we completed a public offering of 2,520,000 7.875% Series A Preferred Units at a price of $25.00 per unit. The total of 2,520,000 Series A Preferred Units includes 320,000 Series A Preferred Units purchased pursuant to the underwriters' over-allotment option. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $60.9 million from this offering, after deducting discounts of $2.0 million and offering costs of $0.1 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Subsidiary Guarantors

We and VNR Finance Corp., our wholly-owned finance subsidiary, may co-issue securities pursuant to the registration statements discussed above. VNR has no independent assets or operations. Debt securities that we may offer may be guaranteed by our subsidiaries. We contemplate that if we offer debt securities, the guarantees will be full and unconditional and joint and several (subject to certain customary release provisions), and any subsidiaries of Vanguard that do not guarantee the securities will be minor.

12. Subsequent Events

Equity Offering

On July 1, 2013, we received proceeds of approximately $8.9 million, after deducting underwriting discounts of $0.3 million, from the sale of an additional 325,000 of our common units at a price of $28.35 per unit. The units sold represent a partial exercise of the option that was offered to the underwriters to purchase additional units to cover over-allotments pursuant to the equity offering completed on June 4, 2013 as discussed in Note 11, Shelf Registration Statements. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Distributions

On July 31, 2013, our board of directors approved an increase to our monthly cash distribution from $0.2050 to $0.2075 per common unit ($2.46 to $2.49 on an annualized basis) effective with our July distribution expected to be paid on September 13, 2013.

On July 18, 2013, our board of directors declared a cash distribution for our common unitholders attributable to the month of June 2013 of $0.2050 per common unit ($2.46 on an annualized basis) expected to be paid on August 14, 2013 to Vanguard unitholders of record on August 1, 2013.

Also on July 18, 2013, our board of directors declared a cash distribution for our preferred unitholders of $0.1641 per preferred unit expected to be paid on August 15, 2013 to Vanguard preferred unitholders of record on August 8, 2013.

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

The historical consolidated financial statements included in this Quarterly Report on Form 10-Q (this "Quarterly Report") reflect all of the assets, liabilities and results of operations of Vanguard Natural Resources, LLC and its Consolidated Subsidiaries. The following discussion analyzes the financial condition and results of operations of Vanguard for the six months ended June 30, 2013 and 2012. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Vanguard in conjunction with our 2012 Annual Report and the historical unaudited consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Overview

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increasing our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Arkoma Basin in Arkansas and Oklahoma;
- the Permian Basin in West Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Piceance Basin in Colorado;
- South Texas;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming;
- the Powder River Basin in Wyoming; and
- Mississippi.

As of June 30, 2013, based on internal reserve estimates, our total estimated proved reserves were 175.7 MMBOE, of which approximately 27% were oil reserves, 56% were natural gas reserves and 17% were NGLs reserves. Of these total estimated proved reserves, approximately 77%, or 134.7 MMBOE, were classified as proved developed. Also, at June 30, 2013, we owned working interests in 7,020 gross (2,557 net) productive wells. Our operated wells accounted for approximately 59% of our total estimated proved reserves at June 30, 2013. Our average net daily production for the six months ended June 30, 2013 and the year ended December 31, 2012 was 34,809 BOE/day and 18,298 BOE/day, respectively. We own working interests in approximately 785,495 gross undeveloped acres surrounding our existing wells. As of June 30, 2013, based on internal reserve estimates, approximately 23%, or 41.0 MMBOE, of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Recent Developments

The NASDAQ Stock Market

On April 11, 2013, we announced the transfer of our stock exchange listing from the New York Stock Exchange to The NASDAQ Global Select Market ("NASDAQ"), an exchange of The NASDAQ OMX Group Inc. (Nasdaq: NDAQ). Our common units commenced trading on the NASDAQ on April 23, 2013 and remain listed under the ticker symbol "VNR."

Acquisition of Oil and Natural Gas Properties

On April 1, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties in the Permian Basin in southeast New Mexico and West Texas from Range Resources Corporation for an adjusted purchase price of $266.3 million. The purchase price was funded with borrowings under our Reserve-Based Credit Facility (defined in Note 3 of the Notes to the Consolidated Financial Statements included in Part I—Item 1—Unaudited Financial Statements) and is subject to customary post-closing adjustments to be determined based on an effective date of January 1, 2013. We refer to this acquisition as the "Range Acquisition."

On June 28, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties located in the San Juan Basin in New Mexico, the D-J Basin in Colorado and the Permian Basin in West Texas from a private seller for an adjusted purchase price of $30.0 million, subject to customary post-closing adjustments. As consideration for the purchase, we issued 1,075,000 VNR common units, at an agreed upon price of $27.65 per common unit, valued at the closing price of $27.90. The effective date of this acquisition is July 1, 2013.

Equity offerings

Common Units

On June 4, 2013, we completed a public offering of 7,000,000 of our common units at a price of $28.35 per unit. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $190.9 million from this offering, after deducting underwriting discounts of $7.4 million and offering costs of $0.1 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility. In July 2013, we received additional proceeds of $8.9 million from the sale of an additional 325,000 of our common units that were purchased by the underwriters to cover over-allotments.

Preferred Units

On June 19, 2013, we completed a public offering of 2,520,000 7.875% Series A Preferred Units at a price of $25.00 per unit. The total of 2,520,000 Series A Preferred Units includes 320,000 Series A Preferred Units purchased pursuant to the underwriters' over-allotment option. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $60.9 million from this offering, after deducting discounts of $2.0 million and offering costs of $0.1 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Business Environment

Price Volatility

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as commodity prices, access to capital, economic, political and regulatory developments, and competition from other sources of energy. Oil, natural gas and NGLs prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, natural gas or NGLs could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, our access to capital and our ability to pay cash distributions to our unitholders. We have mitigated the volatility on our cash flows by entering into oil price derivative contracts through 2016, natural gas price derivative contracts through 2017, and NGLs price derivative contracts through 2014. These hedges are placed on a portion of our proved producing and a portion of our total anticipated production during this time frame. As oil, natural gas and NGLs prices fluctuate, we will recognize non-cash, unrealized gains and losses in our Consolidated Statements of Operations related to the change in fair value of our commodity derivative contracts.

Production Decline

We also face the challenge of oil, natural gas and NGLs production declines. As a given well's initial reservoir pressures are depleted, oil, natural gas and NGLs production decreases, thus reducing our total reserves. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will maintain our focus on controlling costs to add reserves through drilling and acquisitions, as well as controlling the corresponding costs necessary to produce such reserves. During the six months ended June 30, 2013, we drilled 3 gross (1.2 net) operated wells and completed 5 gross (2.0 net) operated wells. We also participated in the drilling of 46 gross (2.2 net) non-operated wells and 41 gross (3.0 net) non-operated wells were completed during the first six months of 2013. Our ability to add production through drilling is dependent on our capital resources and can be limited by many factors, including the ability to timely obtain drilling permits and regulatory approvals as well as voluntary reductions in capital spending in a low commodity price environment. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of our production, which may have an adverse effect on our revenues and as a result, cash available for distribution. In accordance with our business plan, we intend to invest the capital necessary to maintain our cash flow at existing levels over the long-term provided that it is economical to do so based on the commodity price environment. However, we cannot be certain that we will be able to issue our debt or equity securities on favorable terms, or at all, and we may be unable to refinance our borrowings when our credit facilities expire. Additionally, in the event of significant declines in commodity prices, the borrowing base under our Reserve-Based Credit Facility may be redetermined such that it could affect our ability to make distributions.

Impairment of Oil and Natural Gas Properties

We have elected to use the full cost method of accounting to report our oil and natural gas properties. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a “ceiling limit,” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling test write down.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write down would not impact cash flow from operating activities, but it could have a material adverse effect on our GAAP results of operations in the period incurred and would reduce our members’ equity.

In the current natural gas price environment, where the historical 12-month unweighted average of first-day-of-the-month historical price (the “12-month average price”) is significantly less than the expected natural gas prices in future years, it is highly likely that an impairment would be recorded in the quarter in which we complete a natural gas asset acquisition. In accordance with the guidance contained within ASC Topic 805, "Business Combinations," ("ASC Topic 805"), upon the acquisition of oil and natural gas properties, the company records an asset based on the measurement of the fair value of the properties acquired determined using forward oil and natural gas price curves at the acquisitions dates, which can have several price increases over the entire reserve life. As discussed above, capitalized oil and natural gas property costs are limited to a ceiling based on the present value of future net revenues, computed using a flat price for the entire reserve life equal to the historical 12-month average price, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write-down capitalized costs to the ceiling. Furthermore, there is a risk that we will be required to record an impairment of our oil and natural gas properties if certain attributes, such as declining oil and natural gas prices, occur.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013[(a)]	2012[(a)]	2013[(a)]	2012[(a)(b)]
Revenues:				
Oil sales	$69,701	$56,117	$128,217	$120,520
Natural gas sales	36,010	4,570	63,534	14,738
NGLs sales	11,026	5,754	21,668	13,900
Oil, natural gas and NGLs sales	116,737	66,441	213,419	149,158
Realized gain (loss) on commodity derivative contracts	(2,588)	2,165	3,184	(1,074)
Unrealized gain on commodity derivative contracts	61,183	83,309	26,136	60,575
Total revenues	$175,332	$151,915	$242,739	$208,659
Costs and expenses:				
Production:				
Lease operating expenses	$26,509	$16,681	$50,682	$35,240
Production and other taxes	9,964	7,251	19,307	14,111
Depreciation, depletion, amortization, and accretion	42,911	20,855	81,604	42,652
Selling, general and administrative expenses	5,125	3,921	9,946	7,981
Non-cash compensation	1,775	906	3,503	1,818
Total costs and expenses	$86,284	$49,614	$165,042	$101,802
Other income (expense):				
Interest expense	$(15,963)	$(9,830)	$(31,401)	$(15,159)
Realized loss on interest rate derivative contracts	$(962)	$(566)	$(1,909)	$(1,142)
Unrealized gain (loss) on interest rate derivative contracts	$3,374	$(2,623)	$4,036	$(3,044)
Gain on acquisition of oil and natural gas properties, net	$5,827	$14,126	$5,827	$13,796
Other	$(23)	$39	$28	$115

(a) During 2013 and 2012, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included with ours from the closing date of the acquisition forward.

(b) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin in connection with the Unit Exchange. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

Revenues

Oil, natural gas and NGLs sales increased $50.3 million to $116.7 million during the three months ended June 30, 2013 as compared to the same period in 2012. The key oil, natural gas and NGLs revenue measurements were as follows:

	Three Months Ended June 30, 2013[(a)]	2012[(a)]	Percentage Increase / (Decrease)
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$87.38	$81.69	7 %
Natural Gas (Price/Mcf)	$2.73	$2.49	10 %
NGLs (Price/Bbl)	$33.85	$44.47	(24)%
Average realized prices, including hedges[(b)]:			
Oil (Price/Bbl)	$86.31	$82.67	4 %
Natural Gas (Price/Mcf)	$3.17	$5.32	(40)%
NGLs (Price/Bbl)	$34.23	$44.47	(23)%
Total production volumes:			
Oil (MBbls)	798	687	16 %
Natural Gas (MMcf)	13,176	1,839	616 %
NGLs (MBbls)	326	129	153 %
Combined (MBOE)	3,319	1,123	196 %
Average daily production volumes:			
Oil (Bbls/day)	8,765	7,549	16 %
Natural Gas (Mcf/day)	144,795	20,203	617 %
NGLs (Bbls/day)	3,579	1,422	152 %
Combined (BOE/day)	36,477	12,338	196 %

(a) During 2013 and 2012, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included with ours from the closing date of the acquisition forward.
(b) Excludes amortization of premiums paid and amortization on derivative contracts acquired.

The increase in oil, natural gas and NGLs sales during the three months ended June 30, 2013 compared to the same period in 2012 was due primarily to the increase in production from our acquisitions that were completed during 2013 and 2012. Natural gas revenues increased from $4.6 million in the second quarter of 2012 to $36.0 million in the second quarter of 2013 as a result of a 11,337 MMcf increase in our natural gas production volumes. Our average realized natural gas price, including hedges, decreased 40% from $5.32 per Mcf during the three months ended June 30, 2012 compared to $3.17 per Mcf in the same period of 2013, primarily due to a 19% decrease in our weighted average natural gas hedge price. NGLs revenues also increased 92% during the second quarter of 2013 compared to the same period in 2012 primarily due to a 197 MBbls increase in NGLs production volumes, offset by a $10.62 per Bbl decrease in our average realized NGLs price, excluding hedges. Oil revenues increased 24% from $56.1 million in the second quarter of 2012 to $69.7 million in the second quarter of 2013 as a result of an 111 MBbls increase in our oil production volumes and a $5.69 per Bbl, or 7%, increase in our average realized oil price, excluding hedges. This price increase was primarily due to improvements in the Big Horn Basin and Permian Basin oil differentials during the three months ended June 30, 2013, as well as a higher average NYMEX price, which increased from $93.45 per Bbl in the second quarter of 2012 to $94.20 per Bbl in the second quarter of 2013. Overall, our total production for the three months ended June 30, 2013 increased by 196% on a BOE basis compared to the same period in 2012. On a BOE basis, crude oil, natural gas, and NGLs accounted for 24%, 66% and 10%, respectively, of our production during the three months ended June 30, 2013 compared to crude oil, natural gas and NGLs of 61%, 27% and 12%, respectively, of our production during the same period in 2012.

Hedging and Price Risk Management Activities

During the three months ended June 30, 2013, we recognized a $2.6 million realized loss on commodity derivative contracts, of which $5.0 million related to cash received in settlements offset by $0.1 million in amortization of premiums paid during the period and $7.5 million in amortization of the value on derivative contracts acquired. We also recognized a $61.2 million unrealized gain related to the change in fair value of derivative contracts. These realized and unrealized gains resulted from changes in commodity prices.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and by us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our current hedges are not accounted for as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our Consolidated Statements of Operations. However, these fair value changes that are reflected in the Consolidated Statements of Operations only reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses increased by $9.8 million to $26.5 million for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012, of which $8.0 million related to increased lease operating expenses for oil and natural gas properties acquired during the second half of 2012 and first half of 2013. The remaining $1.8 million increase is related to increased maintenance and repair expenses on existing wells and increased plugging and abandonment costs.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $2.7 million for the three months ended June 30, 2013 as compared to the same period in 2012. As a percentage of wellhead revenues, production, severance and ad valorem taxes decreased from 10.9% for the three months ended June 30, 2012 to 8.5% for the three months ended June 30, 2013, primarily due to lower tax rates in New Mexico and Texas on the oil and natural gas properties acquired in the Range Acquisition and an accrued refund from the state of Texas for overpaid severance taxes on oil and natural gas properties in Texas pertaining to marketing cost reductions and tax reimbursements.

Depreciation, depletion, amortization, and accretion increased by approximately $22.1 million to $42.9 million for the three months ended June 30, 2013 from approximately $20.9 million for the three months ended June 30, 2012, primarily due to a higher depletion base associated with properties acquired in the Arkoma Basin Acquisition, the Rockies Acquisition and the Range Acquisition.

Selling, general and administrative expenses include the costs of our employees, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended June 30, 2013 increased $2.1 million to $6.9 million as compared to the three months ended June 30, 2012. The three months ended June 30, 2013 included an approximate $1.0 million increase in non-cash compensation expense related to additional restricted and phantom unit grants in the second half of 2012 and the first half of 2013. Furthermore, the three months ended June 30, 2013 included approximately $1.1 million of increased compensation related expenses due to additional employees.

Other Income and Expense

Interest expense increased to $16.0 million for the three months ended June 30, 2013 from $9.8 million for the three months ended June 30, 2012 primarily due to higher average outstanding debt under the Reserve-Based Credit Facility and a higher interest rate as a result of the Senior Notes offerings completed in April and October 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

Revenues

Oil, natural gas and NGLs sales increased $64.3 million to $213.4 million during the six months ended June 30, 2013 as compared to the same period in 2012. The key oil, natural gas and NGLs revenue measurements were as follows:

	Six Months Ended June 30, 2013[a]	2012[a][b]	Percentage Increase / (Decrease)
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$84.19	$87.39	(4)%
Natural Gas (Price/Mcf)	$2.52	$3.45	(27)%
NGLs (Price/Bbl)	$37.17	$52.00	(29)%
Average realized prices, including hedges[c]:			
Oil (Price/Bbl)	$82.96	$84.67	(2)%
Natural Gas (Price/Mcf)	$3.34	$5.71	(42)%
NGLs (Price/Bbl)	$37.41	$52.00	(28)%
Total production volumes:			
Oil (MBbls)	1,523	1,379	10%
Natural Gas (MMcf)	25,167	4,267	490%
NGLs (MBbls)	583	267	118%
Combined (MBOE)	6,300	2,358	167%
Average daily production volumes:			
Oil (Bbls/day)	8,414	7,578	11%
Natural Gas (Mcf/day)	139,043	23,443	493%
NGLs (Bbls/day)	3,220	1,469	119%
Combined (BOE/day)	34,809	12,953	169%

(a) During 2013 and 2012, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included with ours from the closing date of the acquisition forward.

(b) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin in connection with the Unit Exchange. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(c) Excludes amortization of premiums paid and amortization on derivative contracts acquired.

The increase in oil, natural gas and NGLs sales during the six months ended June 30, 2013 compared to the same period in 2012 was due primarily to the increase in production from our acquisitions that were completed during 2013 and 2012. Natural gas revenues increased 331% from $14.7 million in the first half of 2012 to $63.5 million in the first half of 2013 as a result of a 20,900 MMcf increase in our natural gas production volumes. The impact of the increase in production volumes was offset by a $0.93 per Mcf decrease in our average realized natural gas price received, excluding hedges. Our average realized natural gas price, including hedges, decreased 42% from $5.71 per Mcf during the six months ended June 30, 2012 compared to $3.34 per Mcf in the same period of 2013, primarily due to a 17% decrease in our weighted average gas natural hedge price. NGLs revenues also increased 56% during the first half of 2013 compared to the same period in 2012 primarily due to a 316 MBbls increase in NGLs production volumes, offset by a $14.83 per Bbl, or 29%, decrease in our average realized NGLs price, excluding hedges. Oil revenues increased 6% from $120.5 million in the first half of 2012 to $128.2 million in the first half of 2013 as a result of a 144 MBls increase in our oil production volumes offset by a $3.20 per Bbl, or 4%, decrease in our average realized oil price, excluding hedges. This decrease was primarily due to a lower average NYMEX price, which decreased from $98.21 per Bbl in the first half of 2012 to $94.26 per Bbl in the first half of 2013. Overall, our total production for the six months ended June 30, 2013 increased by 167% on a BOE basis compared to the same period in 2012. On a BOE basis, crude oil, natural gas, and NGLs accounted for 24%, 67% and 9%, respectively, of our production during the six months ended June 30, 2013 compared to crude oil, natural gas and NGLs of 59%, 30% and 11%, respectively, of our production during the same period in 2012.

Hedging and Price Risk Management Activities

During the six months ended June 30, 2013, we recognized a $3.2 million realized gain on commodity derivative contracts, of which $18.7 million related to cash received in settlements offset by $0.1 million in amortization of premiums paid during the period and $15.4 million in amortization of the value on derivative contracts acquired. We also recognized a

$26.1 million unrealized gain related to the change in fair value of derivative contracts. These realized and unrealized gains resulted from changes in commodity prices.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and by us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our current hedges are not accounted for as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our Consolidated Statements of Operations. However, these fair value changes that are reflected in the Consolidated Statements of Operations only reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses increased by $15.4 million to $50.7 million for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012, of which $13.8 million related to increased lease operating expenses for oil and natural gas properties acquired during the second half of 2012 and first half of 2013 and $3.8 million related to increased maintenance and repair expenses on existing wells. Additionally, this increase was offset by approximately $2.2 million of lease operating expenses incurred in the first quarter of 2012 associated with the Appalachian Basin properties divested in March 2012 in connection with the Unit Exchange.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $5.2 million for the six months ended June 30, 2013 as compared to the same period in 2012. As a percentage of wellhead revenues, production, severance and ad valorem taxes were 9.0% and 9.5% for the six months ended June 30, 2013 and June 30, 2012, respectively.

Depreciation, depletion, amortization, and accretion increased by approximately $38.9 million to $81.6 million for the six months ended June 30, 2013 from approximately $42.7 million for the six months ended June 30, 2012, primarily due to a higher depletion base associated with properties acquired in the Arkoma Basin Acquisition, the Rockies Acquisition and the Range Acquisition, offset by a decrease in the depletion base associated with the Appalachian properties divested in connection with the Unit Exchange.

Selling, general and administrative expenses include the costs of our employees, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the six months ended June 30, 2013 increased by $3.7 million to $13.4 million as compared to the six months ended June 30, 2012. The six months ended June 30, 2013 included an approximate $1.7 million increase in non-cash compensation expense related to additional restricted and phantom unit grants in the second half of 2012 and the first half of 2013. Furthermore, the six months ended June 30, 2013 included approximately $1.6 million of increased compensation-related expenses due to additional employees, and approximately $0.4 million in transition fees related to the Rockies Acquisition completed in the fourth quarter of 2012.

Other Income and Expense

Interest expense increased to $31.4 million for the six months ended June 30, 2013 from $15.2 million for the six months ended June 30, 2012 primarily due to higher average outstanding debt under the Reserve-Based Credit Facility and a higher interest rate as a result of the Senior Notes offerings completed in April and October 2012.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of June 30, 2013, our critical accounting policies were consistent with those discussed in our 2012 Annual Report.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in recording the acquisition of oil and natural gas properties and in impairment tests of oil and natural gas properties and goodwill, the fair value of derivative contracts and asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

Liquidity and Capital Resources

Overview

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and the public debt and equity markets for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of oil and natural gas properties; however, we have in the past and expect in the future to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we continually monitor the capital resources available to us to meet future financial obligations, planned capital expenditures, acquisition capital and distributions to our unitholders. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us and our success in drilling for and acquiring additional reserves. We expect to fund our drilling capital expenditures and distributions to unitholders with cash flow from operations, while funding any acquisition capital expenditures that we might incur with borrowings under our Reserve-Based Credit Facility and publicly offered equity or debt, depending on market conditions. As of July 31, 2013, we had $878.3 million available to be borrowed under our Reserve-Based Credit Facility.

Our borrowing base under our Reserve-Based Credit Facility is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank’s petroleum engineers utilizing the bank’s internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. Our current borrowing base is $1.3 billion and the next scheduled redetermination is in October 2013. Absent new acquisitions of oil and natural gas properties, if commodity prices decline in the future and banks lower their internal projections of oil, natural gas and NGLs prices, we will be subject to decreases in our borrowing base availability in the future.

Absent accretive acquisitions, to the extent available after unitholder distributions, debt service and capital expenditures, it is our intention to utilize our excess cash flow to reduce our borrowings under our Reserve-Based Credit Facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient to conduct our business and operations for the foreseeable future.

Cash Flow from Operations

Net cash provided by operating activities was $119.0 million during the six months ended June 30, 2013, compared to $97.6 million during the six months ended June 30, 2012. Changes in working capital decreased total cash flows by $1.5 million for the six months ended June 30, 2013 and increased total cash flows by $14.7 million in the same period in 2012. Contributing to the decrease in working capital during 2013 was a $24.2 million increase in accounts receivable related to the timing of receipts from production from the acquisitions. The decrease in working capital was offset by a $23.2 million increase in accounts payable and oil and natural gas revenue payable and accrued expenses and other current liabilities that resulted primarily from the timing effects of payments. Unrealized derivative gains and losses are non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the six months ended June 30, 2013 or 2012.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and NGLs prices. Oil, natural gas and NGLs prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather, and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, respectively, as well as the prices received for production. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we use a combination of fixed-price swaps, basis swaps, swaptions, put spread options, collars, three-way collars and range bonus accumulators to reduce our exposure to the volatility in oil and natural gas prices. However, unlike natural gas, we are unable to hedge certain oil price differentials which could significantly impact our cash flow from operations. See Note 4. Price and Interest Rate Risk Management Activities in Notes to Consolidated Financial Statements and Part I—Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk, for details about derivative contracts in place through 2017.

Cash Flow from Investing Activities

Net cash used in investing activities was approximately $302.5 million for the six months ended June 30, 2013, compared to $475.7 million during the same period in 2012. Cash used in investing activities during the first six months of 2013 included $270.5 million for the acquisition of oil and natural gas properties, $29.4 million for the drilling and development of oil and natural gas properties, $1.5 million for additions to property and equipment and $1.0 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties. Cash used in investing activities during the first six months of 2012 was primarily attributable to $453.0 million for the acquisition of oil and natural gas properties, $23.4 million for the drilling and development of oil and natural gas properties and $4.4 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties, offset by $5.4 million in proceeds from the sale of leasehold interests in the Williston Basin.

Cash Flow from Financing Activities

Net cash provided by financing activities was approximately $196.6 million for the six months ended June 30, 2013, compared to $375.3 million for the six months ended June 30, 2012. Cash provided by financing activities included net proceeds from our public common unit and preferred unit offerings of $529.0 million and proceeds from borrowings under our long-term debt of $388.5 million. Additionally, cash used in financing activities during the six months ended June 30, 2013 included $638.5 million cash used in the repayments of our long-term debt, $80.3 million cash paid to common unitholders in the form of distributions and $2.1 million paid for financing costs. Net cash provided by financing activities during the six months ended June 30, 2012 included proceeds from borrowings under our long-term debt of $856.0 million and net proceeds from our public common equity offerings of $137.9 million, offset by cash used in financing activities including $545.5 million cash used in the repayments of our long-term debt, $62.6 million cash used in distributions to common unitholders and $10.4 million paid for financing costs.

Debt and Credit Facilities

Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the “Credit Agreement”) provides a maximum credit facility of $1.5 billion and a borrowing base of $1.3 billion (the “Reserve-Based Credit Facility”). As of June 30, 2013, there were $450.0 million of outstanding borrowings and $848.3 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $1.7 million reduction in availability for letters of credit (discussed below).

On April 17, 2013, we entered into the Fourth Amendment to the Credit Agreement, which provided for, among others, (a) the extension of the maturity date to April 16, 2018, (b) the increase of our borrowing base from $1.2 billion to $1.3 billion and (c) increased hedging flexibility. However, under the amended agreement, we are only committed to and paying for a borrowing utilization of $1.2 billion, but we have the flexibility to request the additional $100.0 million of availability if needed in the future.

The applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	<25%	>25% <50%	>50% <75%	>75% <90%	>90%
Eurodollar Loans Margin	1.50 %	1.75 %	2.00 %	2.25 %	2.50 %
ABR Loans Margin	0.50 %	0.75 %	1.00 %	1.25 %	1.50 %
Commitment Fee Rate	0.50 %	0.50 %	0.375 %	0.375 %	0.375 %
Letter of Credit Fee	0.50 %	0.75 %	1.00 %	1.25 %	1.50 %

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. Absent new acquisitions of oil and natural gas properties, if commodity prices decline and banks lower their internal projections of oil, natural gas and NGLs prices, we will be subject to decreases in our borrowing base availability in the future.

Borrowings under the Reserve-Based Credit Facility are available for development and acquisition of oil and natural gas properties, working capital and general limited liability company purposes. Our obligations under the Reserve-Based Credit Facility are secured by substantially all of our assets.

At our election, interest is determined by reference to:

- the London interbank offered rate, or LIBOR, plus an applicable margin between 1.50% and 2.50% per annum; or
- a domestic bank rate plus an applicable margin between 0.50% and 1.50% per annum.

As of June 30, 2013, we had elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

The Reserve-Based Credit Facility contains various covenants that limit our ability to:

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- merge or consolidate; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

The Reserve-Based Credit Facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC Topic 815, "Derivatives and Hedging," which includes the current portion of derivative contracts; and
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 4.0 to 1.0.

We have the ability to borrow under the Reserve-Based Credit Facility to pay distributions to unitholders as long as there has not been a default or an event of default.

We believe that we were in compliance with the terms of our Reserve-Based Credit Facility at June 30, 2013. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the reserve-based credit agreement and exercise other rights and remedies. Each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants in the reserve-based credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $5.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of 2% of the existing borrowing base (to the extent not covered by independent third party insurance provided by insurers of the highest claims paying rating or financial strength as to which the insurer does not dispute coverage and is not subject to insolvency proceeding) or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;

- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year; and
- a change of control, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Exchange Act and the rules and regulations of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Letters of Credit

At June 30, 2013, we have unused irrevocable standby letters of credit of approximately $1.7 million, which expire on December 31, 2013. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit are provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

We and VNRF completed a public offering of Senior Notes on April 4, 2012 and Additional Senior Notes on October 9, 2012. The Additional Senior Notes have identical terms, other than the issue date, and constitute part of the same series as and are fungible with the Senior Notes. Further, like the Senior Notes, the Additional Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured basis, by our Subsidiary Guarantors, subject to the same guaranty release conditions. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to certain customary release provisions, including: (i) upon the sale or other disposition of all or substantially all of the subsidiary's properties or assets, (ii) upon the sale or other disposition of our equity interests in the subsidiary, (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture, (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture, (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities, or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor's Rating Services and Moody's Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At June 30, 2013, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $276.6 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year, beginning on October 1, 2012. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.9375% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter. We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

Off-Balance Sheet Arrangements

At June 30, 2013, we did not have any off-balance sheet arrangements that have, or are reasonably likely to have, an effect on our financial position or results of operations.

Contingencies

We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. There have been no material developments regarding the ENP Litigation as discussed in Part I—Item 3—Legal Proceedings in our 2012 Annual Report, other than as set forth in Part II—Item 1—Legal Proceedings in this Quarterly Report.

Commitments and Contractual Obligations

A summary of our contractual obligations as of June 30, 2013 is provided in the following table (in thousands):

	Payments Due by Year						
	2013	2014	2015	2016	2017	After 2017	Total
Management base salaries	$693	$1,385	$1,385	$—	$—	$—	$3,463
Asset retirement obligations (1)	2,098	5,819	1,943	5,863	1,369	56,869	73,961
Derivative liabilities (2)	10,710	12,902	13,697	7,745	7	—	45,061
Reserved Based Credit Facility (3)	—	—	—	—	—	450,000	450,000
Senior Notes and related interest	21,656	43,313	43,313	43,313	43,312	651,062	845,969
Operating leases	421	856	850	670	683	114	3,594
Development commitments (4)	18,613	—	—	—	—	—	18,613
Firm transportation agreements (5)	3,968	5,756	5,256	4,797	4,146	8,636	32,559
Total	$58,159	$70,031	$66,444	$62,388	$49,517	$1,166,681	$1,473,220

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and the decommissioning of ENP's Elk Basin gas plant. Please read Note 6. Asset Retirement Obligations of the Notes to the Consolidated Financial Statements for additional information regarding our asset retirement obligations.

(2) Represents liabilities for commodity and interest rate derivative contracts, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Part I—Item 3—Quantitative and Qualitative Disclosures About Market Risk and Note 4. Price and Interest Rate Risk Management Activities of the Notes to the Consolidated Financial Statements for additional information regarding our commodity and interest rate derivative contracts.

(3) This table does not include interest to be paid on the Reserve-Based Credit Facility principal balances shown as the interest rates are variable. Please read Note 3. Long-Term Debt of the Notes to the Consolidated Financial Statements for additional information regarding our Reserve-Based Credit Facility.

(4) Represents authorized purchases for work in process.

(5) Represents transportation demand charges. Please read Note 8. Commitments and Contingencies of the Notes to the Consolidated Financial Statements for additional information regarding our firm transportation agreements.

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income (loss) in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) plus the following adjustments:

- Net interest expense, including write-off of deferred financing fees and realized gains and losses on interest rate derivative contracts;
- Depreciation, depletion and amortization (including accretion of asset retirement obligations);
- Amortization of premiums paid on derivative contracts;

- Amortization of value on derivative contracts acquired;
- Unrealized gains and losses on commodity and interest rate derivative contracts;
- Gains on acquisition of oil and natural gas properties, net;
- Taxes;
- Compensation related items, which include unit-based compensation expense and unrealized fair value on phantom units granted to officers; and
- Material transaction costs incurred on acquisitions.

Adjusted EBITDA is a significant performance metric used by management and by external users of our financial statements such as investors, research analysts, and others to assess the financial performance of our assets without regard to financing methods, capital structure, or historical cost basis; the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and our operating performance and return on capital as compared to those of other companies in our industry.

Our Adjusted EBITDA should not be considered as an alternative to net income, operating income, cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

For the three months ended June 30, 2013, as compared to the three months ended June 30, 2012, Adjusted EBITDA increased 81%, from \$44.5 million to \$80.3 million. For the six months ended June 30, 2013 as compared to the six months ended June 30, 2012, Adjusted EBITDA increased 56%, from \$97.7 million to \$152.7 million. The following table presents a reconciliation of consolidated net income to Adjusted EBITDA (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$81,301	$103,447	$54,278	$101,423
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	16,925	10,396	33,310	16,301
Depreciation, depletion, amortization and accretion	42,911	20,855	81,604	42,652
Amortization of premiums paid on derivative contracts	55	3,725	109	6,959
Amortization of value on derivative contracts acquired	7,504	—	15,428	—
Unrealized gains on commodity and interest rate derivative contracts	(64,557)	(80,686)	(30,172)	(57,531)
Gain on acquisition of oil and natural gas properties, net	(5,827)	(14,126)	(5,827)	(13,796)
Taxes	76	(67)	(241)	(137)
Compensation related items	1,775	906	3,503	1,818
Material transaction costs incurred on acquisitions	119	—	722	—

Adjusted EBITDA	$80,282	$44,450	$152,714	$97,689

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas and NGLs prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Conditions sometimes arise where actual production is less than estimated, which has, and could result in over-hedged volumes.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, natural gas and NGLs production. Realized pricing is primarily driven by prevailing spot regional market prices at our primary sales points and the applicable index prices.

Pricing for oil, natural gas and NGLs production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level for an extended period of time we may not be able to add new hedges at similar price levels of existing hedges which would negatively impact our cash flow and may impact our ability to maintain existing distributions to our unitholders. Furthermore, the borrowing base for our Reserve-Based Credit Facility can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes. Furthermore, the risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase.

We enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that mitigate the volatility of future prices received as follows:

- Fixed-price swaps - where we will receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.
- Three-way collar contracts - which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.
- Swaption agreements - where we provide options to counterparties to extend swap contracts into subsequent years.
- Call options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a call option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put spread options - created when we purchase a long put and sell a short put simultaneously.

- Put options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a put option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Range bonus accumulators - a structure that allows us to receive a cash payment when the daily average settlement price remains within a predefined range on each expiry date. Depending on the terms of the contract, if the settlement price is below the floor or above the ceiling on any expiry date, we may have to sell at that level. Range bonus accumulators are used to enhance an existing position or a position that we intend to enter into simultaneously.

In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management's view on future commodity pricing. The amount of oil and natural gas production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Substantially all of our natural gas hedges are at regional sales points in our operating regions, which mitigate the risk of basis differential to the Henry Hub index. Typically, management intends to hedge 75% to 85% of projected oil and natural gas production up to a four year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. Currently, we are unable to hedge oil differentials in certain operating areas which exposes our cash flow to increased volatility in these areas. We have also entered into fixed-price swaps derivative contracts to cover a portion of our NGLs production to reduce exposure to fluctuations in NGLs prices. However, a liquid, readily available and commercially viable market for hedging NGLs has not developed in the same way that exists for crude oil and natural gas. The current direct NGL hedging market is constrained in terms of price, volume, tenor and number of counterparties, which limits our ability to hedge our NGL production effectively or at all. It is never management’s intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract, if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At June 30, 2013, the fair value of commodity derivative contracts was an asset of approximately $103.7 million, of which $38.6 million settles during the next twelve months.

The following table summarizes natural gas commodity derivative contracts in place at June 30, 2013:

	July 1, - December 31, 2013	Year 2014	Year 2015	Year 2016	Year 2017
Gas Positions:					
Fixed Price Swaps:					
Notional Volume (MMBtu)	24,048,800	39,750,225	38,507,500	34,953,000	7,602,000
Fixed Price ($/MMBtu)	$4.58	$4.55	$4.58	$4.67	$4.75

	July 1, - December 31, 2013	Year 2014	Year 2015	Year 2016
Oil Positions:				
Fixed-Price Swaps:				
Notional Volume (Bbls)	1,076,400	1,669,875	438,000	73,200
Fixed Price ($/Bbl)	$90.47	$90.07	$90.38	$92.25
Collars:				
Notional Volume (Bbls)	41,400	12,000	—	—
Floor Price ($/Bbl)	$88.89	$100.00	$—	$—
Ceiling Price ($/Bbl)	$102.36	$116.20	$—	$—
Three-Way Collars:				
Notional Volume (Bbls)	598,000	1,313,850	924,055	549,000
Floor Price ($/Bbl)	$93.85	$93.47	$92.10	$90.00
Ceiling Price ($/Bbl)	$101.67	$101.26	$101.55	$95.00
Put Sold ($/Bbl)	$72.19	$72.57	$72.04	$70.00
Put Spread Options:				
Notional Volume (Bbls)	—	—	255,500	—
Floor Price ($/Bbl)	$—	$—	$100.00	$—
Put Sold ($/Bbl)	$—	$—	$75.00	$—

Total Oil Positions:				
Notional Volume (Bbls)	1,715,800	2,995,725	1,617,555	622,200
Floor Price ($/Bbl)	$91.61	$91.60	$92.88	$90.26

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	July 1, - December 31, 2013	Year 2014
NGLs Positions:		
Fixed-Price Swaps:		
Mont Belvieu Ethane		
Notional Volume (Bbls)	35,678	70,773
Fixed Price ($/Bbl)	$11.03	$11.03
Mont Belvieu Propane		
Notional Volume (Bbls)	26,671	52,907
Fixed Price ($/Bbl)	$37.91	$37.91
Mont Belvieu N. Butane		
Notional Volume (Bbls)	7,599	15,075
Fixed Price ($/Bbl)	$65.62	$65.62
Mont Belvieu Isobutane		
Notional Volume (Bbls)	8,105	16,078
Fixed Price ($/Bbl)	$70.24	$70.24
Mont Belvieu N. Gasoline		
Notional Volume (Bbls)	13,947	27,667
Fixed Price ($/Bbl)	$88.57	$88.57
Total NGLs Positions:		
Notional Volume (Bbls)	92,000	182,500
Fixed Price ($/Bbl)	$40.30	$40.30

As of June 30, 2013, the Company sold the following oil put option contracts:

	July 1, - December 31, 2013	Year 2014	Year 2015	Year 2016
Oil Positions:				
Notional Volume (Bbls)	404,800	—	438,000	73,200
Put Sold ($/Bbl)	$65.34	$—	$70.83	$75.00

As of June 30, 2013, the Company had the following open range bonus accumulators contracts:

	July 1, - December 31, 2013	Year 2014
Oil Positions:		
Notional Volume (Bbls)	368,000	912,500
Bonus ($/Bbl)	$3.88	$4.94
Range Ceiling ($/Bbl)	$104.15	$103.20
Range Floor ($/Bbl)	$72.63	$70.50

The weighted average floor price of the oil positions as of June 30, 2013, including the impact of the range bonus accumulators, is $92.44 for contracts that settle in 2013 and $93.11 for contracts that settle in 2014.

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As of June 30, 2013, the Company had the following open basis swap contracts:

	July 1, - December 31, 2013	Year 2014
Gas Positions:		
Rocky Mountains and NYMEX Henry Hub Basis Differential		
Notional Volume (MMBtu)	460,000	452,500
Weighted-basis differential ($/MMBtu)	$(0.32)	$(0.32)

	July 1, - December 31, 2013	Year 2014	Year 2015
Oil Positions:			
WTI Midland and WTI Cushing Basis Differential			
Notional Volume (Bbls)	294,400	584,000	365,000
Weighted-basis differential ($/Bbl)	$(0.84)	$(0.84)	$(0.90)
West Texas Sour and WTI Cushing Basis Differential			
Notional Volume (Bbls)	165,600	328,500	—
Weighted-basis differential ($/Bbl)	$(1.05)	$(1.05)	$—
Light Louisiana Sweet Crude and WTI Basis Differential			
Notional Volume (Bbls)	42,000	—	—
Weighted-basis differential ($/Bbl)	$9.60	$—	$—
Light Louisiana Sweet Crude and Brent Basis Differential			
Notional Volume (Bbls)	—	182,500	—
Weighted-basis differential ($/Bbl)	$—	$(3.95)	$—

Calls were sold or options provided to counterparties under swaption agreements to extend the swaps into subsequent years as follows:

	July 1, - December 31, 2013	Year 2014	Year 2015	Year 2016
Gas Positions:				
Notional Volume (MMBtu)	—	1,642,500	—	—
Weighted Average Fixed Price ($/MMBtu)	$—	$5.69	$—	$—
Oil Positions:				
Notional Volume (Bbls)	92,000	492,750	508,445	622,200
Weighted Average Fixed Price ($/Bbl)	$99.50	$117.22	$105.98	$125.00

Interest Rate Risks

At June 30, 2013, we had debt outstanding of $1.0 billion. The amount outstanding under our Reserve-Based Credit Facility at June 30, 2013 was $450.0 million and is subject to interest at floating rates based on LIBOR. If the debt remains the same, a 10% increase in LIBOR would result in an estimated $0.02 million increase in annual interest expense after consideration of the interest rate swaps discussed below.

We enter into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. The Company records changes in the fair value of its interest rate derivatives in current earnings under unrealized gains (losses) on interest rate derivative contracts.

The following summarizes information concerning our positions in open interest rate derivative contracts at June 30, 2013 (in thousands):

	July 1, - December 31, 2013	Year 2014	Year 2015[(1)(2)]	Year 2016
Weighted Average Notional Amount	$360,000	$360,000	$344,959	$169,399
Weighted Average Fixed LIBOR Rate	1.30 %	1.30 %	1.27 %	1.49 %

(1) The counterparty has the option to extend the termination date of a contract for a notional amount of $30.0 million at 2.25% to August 5, 2018.

(2) The counterparty has the option to require Vanguard to pay a fixed LIBOR rate of 0.91% for a notional amount of $50.0 million from December 10, 2015 to December 10, 2017.

Counterparty Risk

At June 30, 2013, based upon all of our open derivative contracts shown above and their respective mark to market values, we had the following current and long-term derivative assets and liabilities shown by counterparty with their current S&P financial strength rating in parentheses (in thousands):

	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities	Total Amount Due From/(Owed To) Counterparty at June 30, 2013
Barclays (A+)	$1,476	$3,812	$—	$—	$5,288
BBVA Compass (BBB-)	234	195	—	—	429
BMO (A+)	6,933	1,509	—	—	8,442
CIBC (A+)	2,544	2,637	—	—	5,181
Citibank (A)	—	5,131	(336)	—	4,795
Credit Agricole (A)	—	—	(325)	(692)	(1,017)
Natixis (A)	1,359	2,536	(80)	—	3,815
RBC (AA-)	764	1,507	(1,257)	—	1,014
Scotia Capital (A+)	3,236	5,439	(545)	(1,268)	6,862
Wells Fargo (AA-)	11,557	3,126	(2,128)	(1,551)	11,004
Deutsche Bank (A+)	793	1,251	—	—	2,044
Comerica (A)	—	161	(220)	—	(59)
Fifth Third Bank (BBB+)	4	442	—	—	446
JP Morgan (A)	11,390	35,631	—	—	47,021
Bank of America (A)	1,384	1,926	(487)	(883)	1,940
Total	$41,674	$65,303	$(5,378)	$(4,394)	$97,205

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with our counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (1) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (2) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2013 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonable likely to materially affect our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

We are defendants in legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

We were a party to the ENP Litigation as discussed in Part I—Item 3—Legal Proceedings in our 2012 Annual Report. A detailed discussion on the developments of the ENP Litigation is as follows.

On April 5, 2011, Stephen Bushansky, a purported unitholder of ENP, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption In re: Encore Energy Partners LP Unitholder Litigation, C.A. No. 6347-VCP (the "Delaware State Court Action"). On December 28, 2011, those plaintiffs jointly filed their second amended consolidated class action complaint naming as defendants ENP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action complaint alleged, among other things, that defendants breached the partnership agreement by recommending a transaction that was not fair and reasonable. Plaintiffs sought compensatory damages. Vanguard filed a motion to dismiss this lawsuit. On August 31, 2012, the Chancery Court entered an order granting Vanguard's motion to dismiss the complaint for failure to state a claim and dismissing the Delaware State Court Action with prejudice. On September 27, 2012, Mr. Allen filed a notice of appeal of the dismissal of his lawsuit. On July 22, 2013, the Delaware Supreme Court affirmed the dismissal of the lawsuit.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed below or elsewhere in this Quarterly Report or our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our securities units, please refer to Part I—Item 1A—Risk Factors in our 2012 Annual Report, as supplemented by the risk factor set forth below, and to Part II—Item 1A—Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013. There have been no other material changes to the risk factors set forth in our 2012 Annual Report and Part II—Item 1A—Risk Factors in our Quarterly Report on Form 10-Q for the period ended March 31, 2013.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.
In addition to the discussion in our 2012 Annual Report, on May 24, 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. If new or more stringent federal, state or

local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development or production activities or be precluded from drilling wells.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

EXHIBIT INDEX

Each exhibit identified below is filed as a part of this Report.

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Third Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed June 19, 2013 (File No. 001-33756)
4.1	Specimen Unit Certificate for the Series A Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit B to Exhibit 3.3).	Form 8-K, filed June 19, 2013 (File No. 001-33756)
10.1	Amended and Restated Employment Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Scott W. Smith	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.2	Amended and Restated Employment Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Richard A. Robert	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.3	Form of Restricted Unit Award Agreement	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.4	Form of Phantom Unit Award Agreement	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.5	Fourth Amendment, dated April 16, 2013, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Filed herewith
31.1		Filed herewith

	Certification of Chief Executive Officer Pursuant to Rule 13a -14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a -14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
101.INS	XBRL Instance Document	Furnished herewith
101.SCH	XBRL Schema Document	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document	Furnished herewith
101.DEF	XBRL Definition Linkbase Document	Furnished herewith
101.LAB	XBRL Label Linkbase Document	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document	Furnished herewith

SIGNATURES

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

VANGUARD NATURAL RESOURCES, LLC
(Registrant)

Date: August 1, 2013

/s/ Richard A. Robert
Richard A. Robert
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

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