

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2013

OR

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. Yes 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). Yes 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):

- Large accelerated filer Accelerated filer
 Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

Common units outstanding on April 30, 2013: 68,401,684.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
TABLE OF CONTENTS

Page

PART I – FINANCIAL INFORMATION

<u>Item 1.</u>	<u>Unaudited Financial Statements</u>	
	<u>Consolidated Statements of Operations</u>	<u>3</u>
	<u>Consolidated Balance Sheets</u>	<u>4</u>
	<u>Consolidated Statements of Members' Equity</u>	<u>5</u>
	<u>Consolidated Statements of Cash Flows</u>	<u>6</u>
	<u>Notes to Consolidated Financial Statements</u>	<u>7</u>
<u>Item 2.</u>	<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>26</u>
<u>Item 3.</u>	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	<u>37</u>
<u>Item 4.</u>	<u>Controls and Procedures</u>	<u>41</u>

PART II – OTHER INFORMATION

<u>Item 1.</u>	<u>Legal Proceedings</u>	<u>42</u>
<u>Item 1A.</u>	<u>Risk Factors</u>	<u>42</u>
<u>Item 2.</u>	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	<u>42</u>
<u>Item 3.</u>	<u>Defaults Upon Senior Securities</u>	<u>42</u>
<u>Item 4.</u>	<u>Mine Safety Disclosures</u>	<u>42</u>
<u>Item 5.</u>	<u>Other Information</u>	<u>42</u>
<u>Item 6.</u>	<u>Exhibits</u>	<u>42</u>

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”) 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 March 31,	
	2013	2012
Revenues:		
Oil, natural gas and NGLs sales	\$ 96,682	\$ 82,717
Realized gain (loss) on commodity derivative contracts	5,771	(3,239)
Unrealized loss on commodity derivative contracts	(35,047)	(22,734)
Total revenues	67,406	56,744
Costs and expenses:		
Production:		
Lease operating expenses	24,172	18,559
Production and other taxes	9,343	6,860
Depreciation, depletion, amortization, and accretion	38,693	21,797
Selling, general and administrative expenses	6,549	4,972
Total costs and expenses	78,757	52,188
Income (loss) from operations	(11,351)	4,556
Other income (expense):		
Interest expense	(15,438)	(5,329)
Realized loss on interest rate derivative contracts	(947)	(576)
Unrealized gain (loss) on interest rate derivative contracts	661	(421)
Loss on acquisition of oil and natural gas properties	—	(330)
Other	52	76
Total other expense	(15,672)	(6,580)
Net loss	\$ (27,023)	\$ (2,024)
Net loss per Common and Class B units – basic & diluted	\$ (0.42)	\$ (0.04)
Weighted average units outstanding:		
Common units – basic & diluted	64,369	52,067
Class B units – basic & diluted	420	420

See accompanying notes to consolidated financial statements

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

	March 31, 2013	December 31, 2012
	(Unaudited)	
Assets		
Current assets		
Cash and cash equivalents	\$ 5,272	\$ 11,563
Trade accounts receivable, net	73,646	51,880
Derivative assets	20,914	46,690
Other current assets	3,554	3,858
Total current assets	103,386	113,991
Oil and natural gas properties, at cost	2,145,130	2,126,268
Accumulated depletion, amortization and impairment	(587,760)	(550,032)
Oil and natural gas properties evaluated, net – full cost method	1,557,370	1,576,236
Other assets		
Goodwill	420,955	420,955
Derivative assets	44,397	53,240
Other assets	61,607	35,712
Total assets	\$ 2,187,715	\$ 2,200,134
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	\$ 5,486	\$ 8,417
Affiliates	204	32
Accrued liabilities:		
Lease operating	12,280	7,884
Developmental capital	13,664	4,754
Interest	22,546	11,573
Production and other taxes	15,892	12,852
Derivative liabilities	15,307	5,366
Oil and natural gas revenue payable	8,603	8,226
Distribution payable	13,872	11,919
Other	10,506	8,479
Total current liabilities	118,360	79,502
Long-term debt	1,008,691	1,247,631
Derivative liabilities	9,799	11,996
Asset retirement obligations, net of current portion	60,314	60,096
Other long-term liabilities	3,445	3,445
Total liabilities	1,200,609	1,402,670
Commitments and contingencies (Note 8)		
Members' equity		
Members' capital, 68,261,030 common units issued and outstanding at March 31, 2013 and 58,706,282 at December 31, 2012	984,323	794,426
Class B units, 420,000 issued and outstanding at March 31, 2013 and December 31, 2012	2,783	3,038
Total members' equity	987,106	797,464
Total liabilities and members' equity	\$ 2,187,715	\$ 2,200,134

See accompanying notes to consolidated financial statements

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

	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 members (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
Distributions to members (see Note 9)	—	(39,678)	—	(255)	(39,933)
Issuance of common units, net of offering costs of \$251	9,557	255,869	—	—	255,869
Unit-based compensation	(2)	729	—	—	729
Net loss	—	(27,023)	—	—	(27,023)
Balance at March 31, 2013	68,261	\$ 984,323	420	\$ 2,783	\$ 987,106

See accompanying notes to consolidated financial statements

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

	Three Months Ended March 31,	
	2013	2012
Operating activities		
Net loss	\$ (27,023)	\$ (2,024)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	38,693	21,797
Amortization of deferred financing costs	946	356
Amortization of debt discount	60	—
Deferred taxes	(441)	(56)
Compensation related items	1,728	912
Amortization of premiums paid on derivative contracts	54	3,234
Amortization of value on derivative contracts acquired	7,924	—
Unrealized losses on commodity and interest rate derivative contracts	34,386	23,155
Loss on acquisition of oil and natural gas properties	—	330
Changes in operating assets and liabilities:		
Trade accounts receivable	(21,766)	(2,254)
Payables to affiliates	172	(42)
Other current assets	(51)	5
Price risk management activities, net	(37)	(59)
Accounts payable and oil and natural gas revenue payable	(2,554)	115
Accrued expenses and other current liabilities	25,828	170
Other assets	324	436
Net cash provided by operating activities	58,243	46,075
Investing activities		
Additions to property and equipment	(351)	(120)
Additions to oil and natural gas properties	(14,648)	(8,213)
Acquisitions of oil and natural gas properties	—	(13,518)
Deposits and prepayments of oil and natural gas properties	(28,303)	(709)
Proceeds from the sale of oil and natural gas properties	—	5,377
Net cash used in investing activities	(43,302)	(17,183)
Financing activities		
Proceeds from long-term debt	64,500	48,500
Repayment of long-term debt	(303,500)	(179,500)
Proceeds from equity offerings, net	255,869	136,904
Distributions to members	(37,980)	(31,723)
Financing fees	(121)	(680)
Net cash used in financing activities	(21,232)	(26,499)
Net increase (decrease) in cash and cash equivalents	(6,291)	2,393
Cash and cash equivalents, beginning of period	11,563	2,851
Cash and cash equivalents, end of period	\$ 5,272	\$ 5,244
Supplemental cash flow information:		
Cash paid for interest	\$ 3,535	\$ 4,891
Non-cash investing and financing activities:		
Asset retirement obligations, net	\$ 61	\$ 99
Common units received in exchange for Appalachian Basin properties	\$ —	\$ 52,478
Deferred swap premium	\$ —	\$ 4,863

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 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.

1. Summary of Significant Accounting Policies

The accompanying 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 March 31, 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 March 31, 2013 and December 31, 2012 and for the three months ended March 31, 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) Accounting Standards Update

In December 2011, the Financial Accounting Standards Board ("FASB"), issued Accounting Standards Update ("ASU") No. 2011-11, "*Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*" (ASU 2011-11). This ASU requires disclosures to provide information to help reconcile differences in the offsetting requirements under GAAP and International Financial Reporting Standards. The disclosure requirements of this ASU mandate that entities disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an enforceable master netting arrangement or similar agreement. In addition, this ASU also requires disclosure of collateral received and posted in connection with master netting arrangements or similar arrangements. In January 2013, the FASB issued ASU No. 2013-01, "*Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*" ("ASU 2013-01"), which clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance Accounting Standards Codification ("ASC") Topic 815, "*Derivatives and Hedging*," ("ASC Topic 815") including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in the FASB Accounting Standards Codification ("Codification") or subject to a master netting arrangement or similar agreement. All disclosures provided by the amendments of ASU 2011-11, as updated by ASC 2013-01, are required to be provided retrospectively for all comparative periods presented. We adopted this ASU effective January 1, 2013 and the tabular presentation is included in this Quarterly Report in Note 4. *Price and Interest Rate Risk Management Activities*.

(c) 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 three months ended March 31, 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.

(d) 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.

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."

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."

During 2012, we completed other smaller acquisitions of oil and natural gas properties located in various operating regions. The Company, in the aggregate, paid approximately \$24.8 million in total consideration for these properties. During the three months ended March 31, 2012, one of these acquisitions resulted in goodwill of \$0.3 million, which was immediately impaired and recorded as a loss in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations. 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 months ended March 31, 2012 to show the effect on our consolidated results of operations as if all of our 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 gas properties acquired during 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. 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 loss on acquisition of oil and natural gas properties was excluded from the pro forma results for the three months ended March 31, 2012. The pro forma information is based upon these assumptions and is not necessarily indicative of future results of operations:

	Three Months Ended March 31, 2012	
	Pro forma	
	(in thousands, except per unit data)	
Total revenues	\$	127,489
Net income	\$	13,233
Net income per unit:		
Common & Class B units – basic and diluted	\$	0.26

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:

	Three Months Ended March 31, 2012	
	(in thousands)	
Revenues	\$	3,267
Excess of revenues over direct operating expenses	\$	382

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 March 31,	
	2013	2012
	(in thousands)	
Arkoma Basin Acquisition		
Revenues	\$ 11,913	\$ —
Excess of revenues over direct operating expenses	\$ 9,441	\$ —
Rockies Acquisition		
Revenues	\$ 16,649	\$ —
Excess of revenues over direct operating expenses	\$ 11,713	\$ —
All other acquisitions		
Revenues	\$ 3,143	\$ 8
Excess of revenues over direct operating expenses	\$ 1,807	\$ 8

3. Long-Term Debt

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

Description	Interest Rate	Maturity Date	Amount Outstanding	
			March 31, 2013	December 31, 2012
(in thousands)				
Senior Secured Reserve-Based Credit Facility	Variable(1)	October 31, 2016	\$ 461,000	\$ 700,000
Senior Notes	7.875% (2)	April 1, 2020	550,000	550,000
			\$ 1,011,000	\$ 1,250,000
Unamortized discount on Senior Notes			(2,309)	(2,369)
Total long-term debt			\$ 1,008,691	\$ 1,247,631

(1) Variable interest rate was 1.96% and 2.22% at March 31, 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 \$1.2 billion (the "Reserve-Based Credit Facility"). As of March 31, 2013, there were \$461.0 million of outstanding borrowings and \$737.3 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 with an effective date of April 16, 2013. See Note 12. *Subsequent Events* for further discussion.

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 March 31, 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 March 31, 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 March 31, 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 March 31, 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, \$224.0 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 and natural gas 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 first quarter 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 of NYMEX West Texas Intermediate ("WTI") crude oil drops below the price of the short put. This allows us to settle for WTI 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.
- *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 of crude oil 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 oil 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 fair value of contracts acquired are recognized as a realized loss on commodity or interest rate derivative 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 March 31, 2013, we had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

Contract Period	Gas		Oil		NGLs	
	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average WTI Price	Bbls	Weighted Average Fixed Price
April 1, 2013 – December 31, 2013	34,430,000	\$ 4.57	1,617,900	\$ 90.53	137,501	\$ 40.30
January 1, 2014 – December 31, 2014	37,742,725	\$ 4.58	1,669,875	\$ 90.07	182,501	\$ 40.30
January 1, 2015 – December 31, 2015	36,865,000	\$ 4.60	73,000	\$ 87.10	—	\$ —
January 1, 2016 – December 31, 2016	33,855,000	\$ 4.69	73,200	\$ 87.10	—	\$ —
January 1, 2017 – December 31, 2017	7,602,000	\$ 4.75	—	\$ —	—	\$ —

Swaptions

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

Contract Period	Gas		Oil	
	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average Fixed Price
April 1, 2013 – December 31, 2013	—	—	128,350	\$ 99.82
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

Gas

<u>Contract Period</u>	<u>MMBtu</u>	<u>Weighted Avg. Basis Differential</u>	<u>Pricing Index</u>
April 1, 2013 – December 31, 2013	687,500	\$ (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

Oil

<u>Contract Period</u>	<u>Bbls</u>	<u>Weighted Avg. Basis Differential (\$/Bbl)</u>	<u>Pricing Index</u>
April 1, 2013 – December 31, 2013	440,000	\$ (1.22)	WTI Midland and WTI Cushing Basis Differential
	247,500	\$ (1.05)	WTI Cushing and West Texas Sour Basis Differential
	63,000	\$ 9.60	Light Louisiana Sweet Crude and WTI Basis Differential
January 1, 2014 – December 31, 2014	401,500	\$ (1.05)	WTI Midland and WTI Cushing Basis Differential
	328,500	\$ (1.05)	WTI Cushing and West Texas Sour Basis Differential
	182,500	\$ (3.95)	Light Louisiana Sweet Crude and WTI Brent Basis Differential

Collars

<u>Contract Period</u>	<u>Oil</u>		
	<u>Bbls</u>	<u>Floor</u>	<u>Ceiling</u>
April 1, 2013 – December 31, 2013	61,875	\$ 88.89	\$ 102.36
January 1, 2014 - December 31, 2014	12,000	\$ 100.00	\$ 116.20

Three-Way Collars

<u>Contract Period</u>	<u>Oil</u>			
	<u>Bbls</u>	<u>Floor</u>	<u>Ceiling</u>	<u>Put Sold</u>
April 1, 2013 – December 31, 2013	866,250	\$ 93.97	\$ 101.77	\$ 72.10
January 1, 2014 - December 31, 2014	1,113,250	\$ 94.10	\$ 102.04	\$ 72.13
January 1, 2015 - December 31, 2015	741,555	\$ 92.62	\$ 102.73	\$ 71.31
January 1, 2016 - December 31, 2016	549,000	\$ 90.00	\$ 95.00	\$ 70.00

Puts

We sold oil puts for 2013 on 614,150 barrels at a weighted average price of \$65.26.

Put Spread Options

<u>Contract Period</u>	<u>Oil</u>		
	<u>Bbls</u>	<u>Floor</u>	<u>Put Sold</u>
January 1, 2015 – December 31, 2015	255,500	\$ 100.00	\$ 75.00

Range Bonus Accumulators

<u>Contract Period</u>	<u>Oil</u>			
	<u>Bbls</u>	<u>Bonus</u>	<u>Digital call sold</u>	<u>Put Sold</u>
April 1, 2013 – December 31, 2013	550,000	\$ 3.88	\$ 104.15	\$ 72.63
January 1, 2014 - December 31, 2014	547,500	\$ 3.50	\$ 106.33	\$ 70.83

Interest Rate Swaps

As of March 31, 2013, we had open interest rate derivative contracts as follows (in thousands):

<u>Period</u>	<u>Notional Amount</u>	<u>Fixed Libor Rates</u>
April 1, 2013 to December 10, 2016	\$ 20,000	2.17%
April 1, 2013 to October 31, 2016	\$ 40,000	1.65%
April 1, 2013 to August 5, 2015 ⁽¹⁾	\$ 30,000	2.25%
April 1, 2013 to August 6, 2016	\$ 25,000	1.80%
April 1, 2013 to October 31, 2016	\$ 20,000	1.78%
April 1, 2013 to September 23, 2016	\$ 75,000	1.15%
April 1, 2013 to March 7, 2016	\$ 75,000	1.08%
April 1, 2013 to September 7, 2016	\$ 25,000	1.25%
April 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):

	March 31, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Commodity price derivative contracts	\$ 109,542	\$ (44,235)	\$ 65,307
Interest rate derivative contracts	4	—	4
Total derivative instruments	<u>\$ 109,546</u>	<u>\$ (44,235)</u>	<u>\$ 65,311</u>
Offsetting Derivative Liabilities:			
Commodity price derivative contracts	\$ (59,437)	\$ 44,235	\$ (15,202)
Interest rate derivative contracts	(9,904)	—	(9,904)
Total derivative instruments	<u>\$ (69,341)</u>	<u>\$ 44,235</u>	<u>\$ (25,106)</u>
	December 31, 2012		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Commodity price derivative contracts	\$ 134,905	\$ (35,001)	\$ 99,904
Interest rate derivative contracts	132	(106)	26
Total derivative instruments	<u>\$ 135,037</u>	<u>\$ (35,107)</u>	<u>\$ 99,930</u>
Offsetting Derivative Liabilities:			
Commodity price derivative contracts	\$ (41,775)	\$ 35,001	\$ (6,774)
Interest rate derivative contracts	(10,694)	106	(10,588)
Total derivative instruments	<u>\$ (52,469)</u>	<u>\$ 35,107</u>	<u>\$ (17,362)</u>

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 \$109.5 million at March 31, 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 March 31, 2013.

Gain (Loss) on Derivatives

Gains and losses on derivatives 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. 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 March 31,	
	2013	2012
Realized gains (losses):		
Commodity derivatives	\$ 5,771	\$ (3,239)
Interest rate swaps	(947)	(576)
	<u>\$ 4,824</u>	<u>\$ (3,815)</u>
Unrealized gains (losses):		
Commodity derivatives	\$ (35,047)	\$ (22,734)
Interest rate swaps	661	(421)
	<u>\$ (34,386)</u>	<u>\$ (23,155)</u>
Net losses:		
Commodity derivatives	\$ (29,276)	\$ (25,973)
Interest rate swaps	(286)	(997)
	<u>\$ (29,562)</u>	<u>\$ (26,970)</u>

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, 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 March 31, 2013. We consider this fair value estimate as a Level 1 input.

Our commodity derivative instruments consist of fixed-price swaps, basis swaps, swaptions, put spread options, 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 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):

	March 31, 2013			Assets/Liabilities at Fair value
	Fair Value Measurements Using			
	Level 1	Level 2	Level 3	
Assets:				
Commodity price derivative contracts	\$ —	\$ 65,128	\$ 179	\$ 65,307
Interest rate derivative contracts	—	4	—	4
Total derivative instruments	<u>\$ —</u>	<u>\$ 65,132</u>	<u>\$ 179</u>	<u>\$ 65,311</u>
Liabilities:				
Commodity price derivative contracts	\$ —	\$ (15,202)	\$ —	\$ (15,202)
Interest rate derivative contracts	—	(9,904)	—	(9,904)
Total derivative instruments	<u>\$ —</u>	<u>\$ (25,106)</u>	<u>\$ —</u>	<u>\$ (25,106)</u>

	December 31, 2012			
	Fair Value Measurements Using			Assets/Liabilities at Fair value
	Level 1	Level 2	Level 3	
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 (Level 3) at January 1, 2013	\$ (498)
Total gains	618
Settlements	59
Unobservable inputs (Level 3) at March 31, 2013	\$ 179
Change in unrealized gains included in earnings related to derivatives still held as of March 31, 2013	\$ 677

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 three months ended March 31, 2013 and 2012, in connection with new wells drilled during the period, we incurred and recorded asset retirement obligations totaling \$0.1 million and \$0.2 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 (4.8%); 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 March 31 reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for three months ended March 31, were as follows (in thousands):

	2013	2012
Asset retirement obligations at January 1,	\$ 63,114	\$ 35,920
Liabilities added during the current period	72	195
Accretion expense	591	270
Retirements	(133)	(294)
Total asset retirement obligation at March 31,	63,644	36,091
Less: current obligations	(3,330)	(1,411)
Long-term asset retirement obligation at March 31,	\$ 60,314	\$ 34,680

7. Related Party Transactions

As previously discussed, we owned oil and natural gas properties in the Appalachian Basin that were divested in the Unit Exchange. 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 months ended March 31, 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 months ended March 31, 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 March 31, 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)
April 1, 2013 - December 31, 2013	\$ 5,978
2014	5,756
2015	5,256
2016	4,797
2017	4,146
Thereafter	8,636
Total	\$ 34,569

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 also currently a party to pending litigation related to the ENP Merger ("ENP Litigation") discussed below. 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.

There have been no material developments regarding the ENP Litigation as discussed in Note 8 of the Notes to the Consolidated Financial Statements included in Part II—Item 8—Financial Statements Supplementary Data in our 2012 Annual Report.

9. Common Units and Net Income (loss) per Unit

Basic net income (loss) per unit is computed in accordance with ASC Topic 260 "*Earnings Per Share*" ("ASC Topic 260") by dividing net income (loss) by the weighted average number of units outstanding during the period. Diluted net income (loss) per 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 March 31, 2013, we had two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on the NYSE under the symbol VNR and (ii) Class B units, issued to management and an employee as discussed in Note 10. *Unit-Based Compensation*. The Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic net income (loss) per unit.

For the three months ended March 31, 2012, the 175,000 options previously granted to officers under the Vanguard Natural Resources, LLC Long-Term Incentive Plan ("VNR LTIP") have been excluded in the computation of net income (loss) per unit as they had no dilutive effect. All options were exercised by the officers during the third and fourth quarter of 2012. The 548,184 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 (loss) per unit for the three months ended March 31, 2013 as they had no dilutive effect. Of the 548,184 phantom units granted to date, 115,000 of them were granted to officers prior to March 31, 2012 and have been excluded in the computation of net income (loss) per unit for the three months ended March 31, 2012 as they had no dilutive effect.

In accordance with ASC Topic 260, dual presentation of basic and diluted net income (loss) per unit has been presented in the Consolidated Statements of Operations for the three months ended March 31, 2013 and 2012 including each class of units issued and outstanding during the respective periods: common units and Class B units. Net income (loss) per unit is allocated to the common units and the Class B units on an equal basis.

Distributions Declared. 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 April 19, 2013, our board of directors declared a cash distribution attributable to the month of March 2013. See Note 12. *Subsequent Events* for further discussion.

Cash Distributions

Distribution	Per Unit	Declared Date	Record Date	Payment Date
2013				
First Quarter				
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				
First 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 February 2010, we and VNRH entered into second amended and restated executive employment agreements (the "February Amended Agreements") with two executives. The February Amended Agreements were effective January 1, 2010 and continued until January 1, 2013. These agreements were subject to subsequent one year renewals in the event that neither we, VNRH, nor the executives have given notice to the other parties that the February Amended Agreements should not be extended. In September 2012, the executives gave notice to the compensation committee of the board of directors that the February Amended Agreements should not be extended. New employment contracts are currently being negotiated and are expected to be executed during May 2013.

In June 2010, we and VNRH entered into a second amended and restated executive employment agreement (the "June Amended Agreement" and together with the February Amended Agreements, the "Amended Agreements") with one executive. The June Amended Agreement was effective May 15, 2010 and will continue until May 15, 2013, with subsequent one year renewals in the event that neither we, VNRH, nor the executive have given notice to the other parties that the June Amended Agreement should not be extended. The June Amended Agreement provides for an annual base salary and included an annual bonus structure for the executive. The annual bonus will be calculated based upon two company performance elements, absolute target distribution growth and relative unit performance to peer group, as well as a third discretionary element that will be determined by our Chief Executive Officer. Each of the three components will be weighted equally in calculating the executive officer's annual bonus. The annual bonus does not require a minimum payout, although the maximum payout could not exceed two times the executive's annual base salary.

Restricted and Phantom Units

The February Amended Agreements also provided for each executive to receive an annual grant of 15,000 phantom units granted pursuant to the VNR LTIP and the June Amended Agreement provides for the executive to receive an annual grant of 12,500 phantom units granted pursuant to the VNR LTIP. The phantom units are subject to a three-year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three-year anniversary of the date of grant so long as the executive remains continuously employed with us during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any distributions made by us on our units generally with respect to the number of phantom shares that the executive received pursuant to this grant. In the event the executive is terminated for "Cause" (as such term is defined in the Amended Agreements), all phantom units, whether vested or unvested, will be forfeited. The phantom units, once vested, shall be settled upon the earlier to occur of (a) the occurrence of a "Change of Control" (as defined in the VNR LTIP), or (b) the executive's separation from service. The amount to be paid in connection with these phantom units can be paid in cash or in units at the election of the officers and will be equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2013). Additionally, 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. As of March 31, 2013, an accrued liability of \$2.9 million has been recorded and non-cash unit-based compensation expense of \$1.0 million and \$0.02 million for the three months ended March 31, 2013 and 2012, respectively, has been recognized in the Selling, general and administrative expense line item in the Consolidated Statements of Operations.

During the three months ended March 31, 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. The phantom units are accompanied by dividend equivalent rights, which entitle the board members 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 received pursuant to this grant.

Historically, we have granted restricted common units 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 March 31, 2013 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2012	289,813	\$ 27.97
Forfeited	(2,065)	\$ 29.29
Vested	(66,050)	\$ 27.45
Non-vested units at March 31, 2013	221,698	\$ 28.12

At March 31, 2013, there was approximately \$4.8 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 \$1.7 million and \$0.9 million in the Selling, general and administrative expenses line item for the three months ended March 31, 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. 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 and 2010 Shelf Registration Statement.

Net proceeds, terms and pricing of each offering of securities issued under the 2010 and 2012 Shelf Registration Statements are determined at the time of such offerings. The 2010 and 2012 Shelf Registration Statements do not provide assurance that we will or could sell any such securities. Our ability to utilize the 2010 and 2012 Shelf Registration Statements for the purpose of issuing, from time to time, any combination of debt securities or common 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 representing limited liability company interests 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 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 three months ended March 31, 2013, were approximately \$9.9 million, after commissions, from the sales of 356,813 common units.

As a result of all our previous offerings, we have approximately \$678.8 million remaining available as of March 31, 2013 under our 2010 Shelf Registration Statement.

Equity Offering

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. 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.

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

Acquisition

On February 26, 2013, we entered into a purchase and sale agreement to acquire natural gas, oil and NGLs properties in the Permian Basin in southeast New Mexico and West Texas for a purchase price of \$275.0 million from Range Resources Corporation. We refer to this acquisition as the "Range Permian Acquisition." We completed this acquisition on April 1, 2013 for an adjusted purchase price of \$268.8 million. The purchase price was funded with borrowings under our Reserve-Based Credit Facility and is subject to customary post-closing adjustments to be determined based on an effective date of January 1, 2013.

Fourth Amendment to the Credit Agreement

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.

Distributions

On April 19, 2013, our board of directors declared a cash distribution attributable to the month of March 2013 of \$0.2025 per common unit (\$2.43 on an annualized basis) expected to be paid on May 15, 2013 to Vanguard unitholders of record as of the close of business on May 1, 2013. In addition, on April 30, 2013, our board of directors approved an increase to our monthly cash distribution from \$0.2025 to \$0.2050 per common unit (\$2.43 to \$2.46 on an annualized basis) effective with our April distribution expected to be paid on June 14, 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 three months ended March 31, 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 March 31, 2013, based on internal reserve estimates, our total estimated proved reserves were 151.1 MMBOE, of which approximately 27% were oil reserves, 60% were natural gas reserves and 13% were NGLs reserves. Of these total estimated proved reserves, approximately 73%, or 110.3 MMBOE, were classified as proved developed. Also, at March 31, 2013, we owned working interests in 7,012 gross (2,357 net) productive wells. Our operated wells accounted for approximately 53% of our total estimated proved reserves at March 31, 2013. Our average net daily production for the year ended December 31, 2012 and for the three months ended March 31, 2013 was 18,298 BOE/day and 33,122 BOE/day, respectively. We own working interests in approximately 785,495 gross undeveloped acres surrounding our existing wells. As of March 31, 2013, based on internal reserve estimates, approximately 27%, or 40.8 MMBOE, of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Recent Developments

Acquisition of Oil and Natural Gas Properties

On February 26, 2013, we entered into a purchase and sale agreement to acquire natural gas, oil and NGLs properties in the Permian Basin in southeast New Mexico and West Texas from Range Resources Corporation. We refer to this acquisition as the "Range Permian Acquisition." We completed this acquisition on April 1, 2013 for an adjusted purchase price of \$268.8 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. Based on internal reserve estimates, the interests acquired have estimated total net proved reserves of 22.8 MMBOE, of which, 43% is natural gas and 78% is proved developed.

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."

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 and natural gas 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 first quarter of 2013, we drilled 3 gross (1.2 net) operated wells. We also participated in the drilling of 31 gross (1.7 net) non-operated wells and 19 gross (1.5 net) non-operated wells were completed during the first quarter 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. As a result, 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, continue.

Results of Operations

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

	Three Months Ended March 31,	
	2013	2012^{(a)(b)}
Revenues:		
Oil sales	\$ 58,516	\$ 64,403
Natural gas sales	27,524	10,168
NGLs sales	10,642	8,146
Oil, natural gas and NGLs sales	96,682	82,717
Realized gain (loss) on commodity derivative contracts	5,771	(3,239)
Unrealized loss on commodity derivative contracts	(35,047)	(22,734)
Total revenues	\$ 67,406	\$ 56,744
Costs and expenses:		
Production:		
Lease operating expenses	\$ 24,172	\$ 18,559
Production taxes and marketing	9,343	6,860
Depreciation, depletion, amortization and accretion	38,693	21,797
Selling, general and administrative expenses	6,549	4,972
Total costs and expenses	\$ 78,757	\$ 52,188
Other income (expense):		
Interest expense	\$ (15,438)	\$ (5,329)
Realized loss on interest rate derivative contracts	\$ (947)	\$ (576)
Unrealized gain (loss) on interest rate derivative contracts	\$ 661	\$ (421)
Loss on acquisition of oil and natural gas properties	\$ —	\$ (330)
Other	\$ 52	\$ 76

(a) During 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 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 March 31, 2013 Compared to Three Months Ended March 31, 2012

Revenues

Oil, natural gas and NGLs sales increased \$14.0 million to \$96.7 million during the three months ended March 31, 2013 as compared to the same period in 2012. The key oil, natural gas and NGLs revenue measurements were as follows:

	Three Months Ended March 31,		Percentage Increase / (Decrease)
	2013	2012^{(a)(b)}	
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	\$ 80.67	\$ 93.04	(13)%
Natural Gas (Price/Mcf)	\$ 2.30	\$ 4.19	(45)%
NGLs (Price/Bbl)	\$ 41.38	\$ 59.08	(30)%
Average realized prices, including hedges ^(c) :			
Oil (Price/Bbl)	\$ 79.29	\$ 86.66	(9)%
Natural Gas (Price/Mcf)	\$ 3.52	\$ 6.01	(41)%
NGLs (Price/Bbl)	\$ 41.44	\$ 59.08	(30)%
Total production volumes:			
Oil (MBbls)	725	692	5 %
Natural Gas (MMcf)	11,990	2,428	394 %
NGLs (MBbls)	257	138	86 %
Combined (MBOE)	2,981	1,235	141 %
Average daily production volumes:			
Oil (Bbls/day)	8,060	7,606	6 %
Natural Gas (Mcf/day)	133,227	26,684	399 %
NGLs (Bbls/day)	2,858	1,515	89 %
Combined (BOE/day)	33,122	13,569	144 %

- (a) During 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 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 three months ended March 31, 2013 compared to the same period in 2012 was due primarily to the increase in production from our acquisitions that were completed during 2012. Natural gas revenues increased 171% from \$10.2 million in the first quarter of 2012 to \$27.5 million in the first quarter of 2013 as a result of a 9,562 MMcf increase in our natural gas production volumes. The impact of the increase in production volumes was offset by a \$1.89 per Mcf decrease in our average realized natural gas price received, excluding hedges. NGLs revenues also increased 31% during the first quarter of 2013 compared to the same period in 2012 primarily due to a 119 MBbls increase in NGLs production volumes, offset by a \$17.70 decrease in our average realized NGLs price. Oil revenues decreased 9% from \$64.4 million in the first quarter of 2012 to \$58.5 million in the first quarter of 2013 as a result of a \$12.37 decrease in our average realized oil price, excluding hedges. This decrease was primarily due to a lower average NYMEX price, which decreased from \$101.03 per Bbl in the first quarter of 2012 to \$94.32 per Bbl in the first quarter of 2013. However, the impact of the decrease in our average realized oil price was offset by a 33 MBbls increase in our oil production volumes. Overall, our total production three months ended March 31, 2013 increased by 141% 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 three months ended March 31, 2013 compared to crude oil, natural gas and NGLs of 56%, 33% and 11%, respectively, during the same period in 2012.

Hedging and Price Risk Management Activities

During the three months ended March 31, 2013, we recognized a \$5.8 million realized gain on commodity derivative contracts, of which, \$13.8 million related to cash received in settlements offset by \$0.1 million in amortization of premiums paid during the period and \$7.9 million in amortization of the value on derivative contracts acquired. We also recognized a \$35.0 million unrealized loss related to the change in fair value of derivative contracts. These realized and unrealized gains resulted from the changes in commodity prices and the effect of these price changes is discussed in the paragraph below.

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 again 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 \$5.6 million to \$24.2 million for the three months ended March 31, 2013 as compared to the three months ended March 31, 2012, of which \$5.8 million related to increased lease operating expenses for oil and natural gas properties acquired during the second and fourth quarters of 2012 and \$1.9 million related to increased maintenance and repair expenses on existing wells. Additionally, this increase was offset by approximately \$2.1 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 \$2.5 million for the three months ended March 31, 2013 as compared to the same period in 2012. As a percentage of wellhead revenues, production, severance and ad valorem taxes increased from 8.3% for the three months ended March 31, 2012 to 9.7% for the three months ended March 31, 2013, primarily due to higher tax rates in Wyoming on oil and natural gas properties acquired in the Rockies Acquisition.

Depreciation, depletion, amortization and accretion increased by approximately \$16.9 million to \$38.7 million for the three months ended March 31, 2013 from approximately \$21.8 million for the three months ended March 31, 2012, primarily due to a higher depletion base associated with properties acquired in the Arkoma Basin Acquisition and the Rockies Acquisition, offset by a lower depletion base associated with the Appalachian properties divested in connection with the Unit Exchange.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended March 31, 2013 increased \$1.6 million to \$6.5 million as compared to the three months ended March 31, 2012. The three months ended March 31, 2013 included approximately \$0.8 million increase in non-cash compensation expense related to additional restricted and phantom unit grants in the second half of 2012 and the first quarter of 2013. Furthermore, the three months ended March 31, 2013 included approximately \$0.5 million of increased compensation related expenses due to additional employees and a \$0.4 million increase in transition related fees due to the Rockies Acquisition completed in the fourth quarter of 2012.

Other Income and Expense

Interest expense increased to \$15.4 million for the three months ended March 31, 2013 from \$5.3 million for the three months ended March 31, 2012 primarily due to 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 March 31, 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 April 30, 2013, we had \$584.8 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 \$58.2 million during the three months ended March 31, 2013, as compared to \$46.1 million during the three months ended March 31, 2012. Changes in working capital increased total cash flows by \$1.9 million in the first quarter of 2013 and by \$1.6 million in the same period in 2012. Contributing to the decrease in working capital during 2013 was a \$21.8 million increase in accounts receivable and a \$2.6 million decrease in accounts payable and oil and natural gas revenue payable. The decrease in working capital was offset by a \$25.8 million increase in 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 three months ended March 31, 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 derivatives in place through 2017.

Cash Flow from Investing Activities

Cash used in investing activities was approximately \$43.3 million for the three months ended March 31, 2013, as compared to \$17.2 million during the same period in 2012. Cash used in investing activities during the first three months of 2013 was primarily attributable to \$28.3 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties and \$14.6 million for the drilling and development of oil and natural gas properties. Cash used in investing activities during the first three months of 2012 was primarily attributable to \$8.2 million for the drilling and development of oil and natural gas properties, \$13.5 million for the acquisition of oil and natural gas properties, and \$0.7 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 divestiture of certain oil and natural gas properties in the Permian Basin.

Cash Flow from Financing Activities

Cash used in financing activities was approximately \$21.2 million for the three months ended March 31, 2013, as compared to \$26.5 million for the three months ended March 31, 2012. Cash used in financing activities during the three months ended March 31, 2013 included \$303.5 million cash used in the repayments of our long-term debt, \$38.0 million cash paid to unitholders in the form of distributions and \$0.1 million was paid for financing costs. Additionally, cash provided by financing activities included net proceeds from our public equity offerings of \$255.9 million and proceeds from borrowings under our long-term debt of \$64.5 million. Cash used in financing activities during the three months ended March 31, 2012 included cash of \$131.0 million used in the repayments of our long-term debt, net of proceeds from long-term debt of \$48.5 million, \$31.7 million was used in distributions to unitholders and financing costs paid of \$0.7 million, offset by net proceeds from our public equity offerings of \$136.9 million.

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 \$1.2 billion (the "Reserve-Based Credit Facility"). As of March 31, 2013 there were \$461.0 million of outstanding borrowings and \$737.3 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 March 31, 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 March 31, 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 March 31, 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 March 31, 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, \$224.0 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 March 31, 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 March 31, 2013 is provided in the following table (in thousands):

	Payments Due by Year (in thousands)						Total
	2013	2014	2015	2016	2017	After 2017	
Management base salaries	\$ 262	\$ 131	\$ —	\$ —	\$ —	\$ —	\$ 393
Asset retirement obligations ⁽¹⁾	2,969	6,081	1,001	3,241	1,214	49,138	63,644
Derivative liabilities ⁽²⁾	26,591	19,358	13,949	9,433	10	—	69,341
Reserved Based Credit Facility ⁽³⁾	—	—	—	—	—	461,000	461,000
Senior Notes and related interest	32,484	43,313	43,313	43,313	43,313	651,063	856,799
Operating leases	300	686	677	493	503	84	2,743
Development commitments ⁽⁴⁾	15,234	—	—	—	—	—	15,234
Firm transportation agreements ⁽⁵⁾	5,978	5,756	5,256	4,797	4,146	8,636	34,569
Total	\$ 83,818	\$ 75,325	\$ 64,196	\$ 61,277	\$ 49,186	\$ 1,169,921	\$ 1,503,723

(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;
- Net gains and losses on acquisition of oil and natural gas properties;
- Taxes;
- Compensation related items, which include unit-based compensation expense and unrealized fair value of phantom units granted to officers; and
- Material transaction costs incurred on acquisitions.

Adjusted EBITDA is a significant performance metric used by management as a tool to measure (prior to the establishment of any cash reserves by our board of directors, debt service and capital expenditures) the cash distributions we could pay our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our monthly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our 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 (loss), operating income (loss), 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 (loss) and operating income (loss) 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 March 31, 2013 as compared to the three months ended March 31, 2012, Adjusted EBITDA attributable to Vanguard unitholders increased 36%, from \$53.2 million to \$72.4 million. The following table presents a reconciliation of consolidated net loss to Adjusted EBITDA (in thousands):

	Three Months Ended	
	March 31,	
	2013	2012
Net loss	\$ (27,023)	\$ (2,024)
Plus:		
Interest expense, including realized losses on interest rate derivative contracts	16,385	5,905
Depreciation, depletion, amortization and accretion	38,693	21,797
Amortization of premiums paid on derivative contracts	54	3,234
Amortization of value on derivative contracts acquired	7,924	—
Unrealized losses on commodity and interest rate derivative contracts	34,386	23,155
Loss on acquisition of oil and natural gas properties	—	330
Taxes	(317)	(70)
Compensation related items	1,728	912
Material transaction costs incurred on acquisitions	603	—
Adjusted EBITDA	\$ 72,433	\$ 53,239

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, 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 of NYMEX WTI crude oil drops below the price of the short put. This allows us to settle for WTI 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.
- *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 of crude oil 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 oil 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. 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 March 31, 2013, the fair value of commodity derivative contracts was an asset of approximately \$50.1 million, of which \$8.8 million settles during the next twelve months.

The following table summarizes natural gas commodity derivative contracts in place at March 31, 2013:

	April 1, - December 31, 2013	Year 2014	Year 2015	Year 2016	Year 2017
Gas Positions:					
Fixed Price Swaps:					
Notional Volume (MMBtu)	34,430,000	37,742,725	36,865,000	33,855,000	7,602,000
Fixed Price (\$/MMBtu)	\$ 4.57	\$ 4.58	\$ 4.60	\$ 4.69	\$ 4.75
	April 1, - December 31, 2013	Year 2014	Year 2015	Year 2016	Year 2016
Oil Positions:					
Fixed Price Swaps:					
Notional Volume (Bbls)	1,617,900	1,669,875	73,000	73,200	73,200
Fixed Price (\$/Bbl)	\$ 90.53	\$ 90.07	\$ 87.10	\$ 87.10	\$ 87.10
Collars:					
Notional Volume (Bbls)	61,875	12,000	—	—	—
Floor Price (\$/Bbl)	\$ 88.89	\$ 100.00	\$ —	\$ —	\$ —
Ceiling Price (\$/Bbl)	\$ 102.36	\$ 116.20	\$ —	\$ —	\$ —
Three-Way Collars:					
Notional Volume (Bbls)	866,250	1,113,250	741,555	549,000	549,000
Floor Price (\$/Bbl)	\$ 93.97	\$ 94.10	\$ 92.62	\$ 90.00	\$ 90.00
Ceiling Price (\$/Bbl)	\$ 101.77	\$ 102.04	\$ 102.73	\$ 95.00	\$ 95.00
Put Sold (\$/Bbl)	\$ 72.10	\$ 72.13	\$ 71.31	\$ 70.00	\$ 70.00
Put Spreads:					
Notional Volume (Bbls)	—	—	255,500	—	—
Floor Price (\$/Bbl)	\$ —	\$ —	\$ 100.00	\$ —	\$ —
Put Sold (\$/Bbl)	\$ —	\$ —	\$ 75.00	\$ —	\$ —
Total Oil Positions:					
Notional Volume (Bbls)	2,546,025	2,795,125	1,070,055	622,200	622,200
Floor Price (\$/Bbl)	\$ 91.66	\$ 91.72	\$ 94.01	\$ 89.66	\$ 89.66

	April 1, - December 31, 2013	Year 2014
NGLs Positions:		
Fixed Price Swaps:		
Mont Belvieu Ethane		
Notional Volume (Bbls)	53,323	70,774
Fixed Price (\$/Bbl)	\$ 11.03	\$ 11.03
Mont Belvieu Propane		
Notional Volume (Bbls)	39,861	52,907
Fixed Price (\$/Bbl)	\$ 37.91	\$ 37.91
Mont Belvieu N. Butane		
Notional Volume (Bbls)	11,358	15,075
Fixed Price (\$/Bbl)	\$ 65.62	\$ 65.62
Mont Belvieu Isobutane		
Notional Volume (Bbls)	12,114	16,078
Fixed Price (\$/Bbl)	\$ 70.24	\$ 70.24
Mont Belvieu N. Gasoline		
Notional Volume (Bbls)	20,845	27,667
Fixed Price (\$/Bbl)	\$ 88.57	\$ 88.57
Total NGLs Positions:		
Notional Volume (Bbls)	137,501	182,501
Fixed Price (\$/Bbl)	\$ 40.30	\$ 40.30

We sold oil puts for 2013 on 614,150 barrels at a weighted average price of \$65.26.

As of March 31, 2013, the Company had the following open range bonus accumulators contracts:

	April 1, - December 31, 2013	Year 2014
Oil Positions:		
Notional Volume (Bbls)	550,000	547,500
Bonus (\$/Bbl)	\$ 3.88	\$ 3.50
Digital call sold (\$/Bbl)	\$ 104.15	\$ 106.33
Put Sold (\$/Bbl)	\$ 72.63	\$ 70.83

The weighted average floor price of the oil positions as of March 31, 2013, including the impact of the range bonus accumulators, is \$92.50 for contracts that settle in 2013 and \$92.40 for contracts that settle in 2014.

As of March 31, 2013, the Company had the following open basis swap contracts:

	April 1, - December 31, 2013	Year 2014
Gas Positions:		
Rocky Mountains and NYMEX Henry Hub Basis Differential		
Notional Volume (MMBtu)	687,500	452,500
Weighted-basis differential (\$/MMBtu)	\$ (0.32)	\$ (0.32)

	April 1, - December 31, 2013	Year 2014
Oil Positions:		
WTI Midland and WTI Cushing Basis Differential		
Notional Volume (Bbls)	440,000	401,500
Weighted-basis differential (\$/Bbl)	\$ (1.22)	\$ (1.05)
WTI Cushing and West Texas Sour Basis Differential		
Notional Volume (Bbls)	247,500	328,500
Weighted-basis differential (\$/Bbl)	\$ (1.05)	\$ (1.05)
Light Louisiana Sweet Crude and WTI Brent Basis Differential		
Notional Volume (Bbls)	—	182,500
Weighted-basis differential (\$/Bbl)	\$ —	\$ (3.95)
Light Louisiana Sweet Crude and WTI Basis Differential		
Notional Volume (Bbls)	63,000	—
Weighted-basis differential (\$/Bbl)	\$ 9.60	\$ —

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

	April 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)	128,350	492,750	508,445	622,200
Weighted Average Fixed Price (\$/Bbl)	\$ 99.82	\$ 117.22	\$ 105.98	\$ 125.00

Interest Rate Risks

At March 31, 2013, we had debt outstanding of \$1.0 billion. The amount outstanding under our Reserve-Based Credit Facility at March 31, 2013 was \$461.0 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 March 31, 2013 (in thousands):

	April 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 March 31, 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 March 31, 2013
Barclays (A+)	\$ —	\$ 1,912	\$ (897)	\$ —	\$ 1,015
BBVA Compass (BBB-)	76	97	—	—	173
BMO (A+)	6,922	1,336	—	—	8,258
CIBC (A+)	—	1,353	(291)	—	1,062
Citibank (A)	—	4,079	(831)	—	3,248
Credit Agricole (A)	—	—	(435)	(1,042)	(1,477)
Natixis (A)	984	529	(329)	—	1,184
RBC (AA-)	1	440	(2,750)	(639)	(2,948)
Scotia Capital (A+)	—	2,440	(1,317)	(1,968)	(845)
Wells Fargo (AA-)	12,931	—	(4,313)	(4,584)	4,034
Deutsche Bank (A+)	—	487	(478)	—	9
Comerica (A)	—	—	(323)	(200)	(523)
JP Morgan (A)	—	31,175	(1,608)	—	29,567
Bank of America (A)	—	549	(1,735)	(1,366)	(2,552)
Total	\$ 20,914	\$ 44,397	\$ (15,307)	\$ (9,799)	\$ 40,205

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 March 31, 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 first 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.

There have been no material developments regarding the ENP Litigation as discussed in Part I—Item 3—Legal Proceedings in our 2012 Annual Report.

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 common units, please refer to Part I—Item 1A—Risk Factors in our 2012 Annual Report, as supplemented by the risk factor set forth below. There have been no material changes to the risk factors set forth in our 2012 Annual Report, other than as set forth below.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these nonoperated properties, including timing of drilling and other scheduled operations activities, compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

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	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.1	Purchase and Sale Agreement, dated February 26, 2013 among Vanguard Permian, LLC and Range Resources Corporation	Form 8-K, filed March 4, 2013 (File No. 001-33756)
31.1	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	Filed herewith
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: May 2, 2013

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

**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**

I, Scott W. Smith, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 2, 2013

/s/ Scott W. Smith

Scott W. Smith

President and Chief Executive Officer

(Principal Executive Officer)

Vanguard Natural Resources, LLC

**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**

I, Richard A. Robert, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 2, 2013

/s/ Richard A. Robert

Richard A. Robert

Executive Vice President and

Chief Financial Officer

(Principal Financial Officer and Principal Accounting Officer)

Vanguard Natural Resources, LLC

**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**

In connection with the Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott W. Smith, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Scott W. Smith

Scott W. Smith

President and Chief Executive Officer
(Principal Executive Officer)

May 2, 2013

**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**

In connection with the Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard A. Robert, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Richard A. Robert

Richard A. Robert

Executive Vice President and Chief Financial Officer

(Principal Financial Officer and Principal Accounting Officer)

May 2, 2013

