Vanguard Natural Resources, LLC
Form 10-Q
May 04, 2012

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2012

OR

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

For the transition period from to

Commission File Number: 001-33756

Vanguard Natural Resources, LLC
(Exact Name of Registrant as Specified in Its Charter)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
x Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Common units outstanding on May 1, 2012: 51,590,542

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
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GLOSSARY OF TERMS

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

/day	= per day	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
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 NGLs and oil with quantities of natural gas 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”), 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 (“ECFP”).

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.

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, 2011 (the “2011 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, 2012	Three Months Ended March 31, 2011
Revenues:		
Oil, natural gas and NGLs sales	$ 82,717	$ 72,039
Loss on commodity cash flow hedges	—	(1,071)
Realized gain (loss) on commodity derivative contracts	(3,239)	1,379
Unrealized loss on commodity derivative contracts	(22,734)	(72,560)
Total revenues	56,744	(213)
Costs and expenses:		
Production:		
Lease operating expenses	18,559	12,332
Production and other taxes	6,860	6,222
Depreciation, depletion, amortization, and accretion	21,797	19,827
Selling, general and administrative expenses	4,972	4,876
Total costs and expenses	52,188	43,257
Income (loss) from operations	4,556	(43,470)
Other income (expense):		
Interest expense	(5,329)	(6,787)
Realized loss on interest rate derivative contracts	(576)	(893)
Unrealized gain (loss) on interest rate derivative contracts	(421)	1,102
Loss on acquisition of oil and natural gas properties	(330)	—
Other	76	(2)
Total other expense	(6,580)	(6,580)
Net loss	$ (2,024)	$ (50,050)
Less:		
Net loss attributable to non-controlling interest	—	(19,638)
Net loss attributable to Vanguard unitholders	$ (2,024)	$ (30,412)
Net loss per Common and Class B units – basic & diluted	$ (0.04)	$ (1.01)

Weighted average units outstanding:		
Common units – basic & diluted	52,067	29,725
Class B units – basic & diluted	420	420

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(Unaudited)
(in thousands)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Net loss	$ (2,024)	$ (50,050)
Net gains from derivative contracts:		
Reclassification adjustments for cash flow hedge settlements	—	1,032
Other comprehensive income	—	1,032
Comprehensive loss	$ (2,024)	$ (49,018)

See accompanying notes to consolidated financial statements

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

	March 31, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 5,244	$ 2,851
Trade accounts receivable, net	49,075	48,046
Derivative assets	786	2,333
Other current assets	2,894	3,462
Total current assets	57,999	56,692
Oil and natural gas properties, at cost	1,385,303	1,549,821
Accumulated depletion	(221,623)	(331,836)
Oil and natural gas properties evaluated, net – full cost method	1,163,680	1,217,985
Other assets		
Goodwill	420,955	420,955
Derivative assets	2,041	1,105
Other assets	20,376	19,626
Total assets	$ 1,665,051	$ 1,716,363
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 3,599	$ 7,867
Affiliate	1,637	718
Accrued liabilities:		
Lease operating	5,371	5,828
Developmental capital	1,402	563
Interest	201	103
Production and other taxes	12,459	12,768
Derivative liabilities	17,289	12,774
Deferred swap premium liability	4,655	275
Oil and natural gas revenue payable	4,555	505
Other	4,616	4,437
Total current liabilities	55,784	45,838
Long-term debt	640,000	771,000
Derivative liabilities	35,575	20,553
Asset retirement obligations, net of current portion	34,680	34,776
Other long-term liabilities	3,651	275
Total liabilities	769,690	872,442
Commitments and contingencies (Note 8)		
Members' equity		
	891,401	839,714

Members' capital, 51,574,275 common units issued and outstanding at March 31, 2012 and 48,320,104 at December 31, 2011				
Class B units, 420,000 issued and outstanding at March 31, 2012 and December 31, 2011		3,960		4,207
Total members' equity		895,361		843,921
Total liabilities and members' equity	$	1,665,051	$	1,716,363

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, 2012 AND THE YEAR ENDED DECEMBER 31, 2011
(in thousands, except per unit data)
(Unaudited)

	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Members' Equity
Balance at December 31, 2010	29,666	$ 318,597	420	$ 5,166	$ (3,032)	$ 548,662	$ 869,393
Distributions to members ($0.56 per unit to unitholders of record February 7, 2011, $0.57 per unit to unitholders of record May 6, 2011, $0.575 per unit to unitholders of record August 5, 2011, $0.5775 per unit to unitholders of record November 7, 2011)	—	(68,068)	—	(959)	—	—	(69,027)
Issuance of common units in connection with the ENP Merger and equity offering, net of merger costs of $2,503 and offering costs of $126	18,439	524,697	—	—	—	(527,326)	(2,629)
Unit-based compensation	215	2,425	—	—	—	—	2,425
Net income	—	62,063	—	—	—	26,067	88,130
Settlement of cash flow hedges in other comprehensive	—	—	—	—	3,032	—	3,032

income							
ENP cash distribution to non-controlling interest	—	—	—	—	—	(47,403)	(47,403)
Balance at December 31, 2011	48,320	$ 839,714	420	$ 4,207	$ —	—	$ 843,921
Distributions to members ($0.5875 per unit to unitholders of record February 7, 2012)	—	(31,476)	—	(247)	—	—	(31,723)
Issuance of common units, net of offering costs of $581	5,140	136,904	—	—	—	—	136,904
Common units received in exchange for Appalachian Basin properties	(1,900)	(52,478)	—	—	—	—	(52,478)
Unit-based compensation	14	761	—	—	—	—	761
Net loss	—	(2,024)	—	—	—	—	(2,024)
Balance at March 31, 2012	51,574	$ 891,401	420	$ 3,960	$ —	—	$ 895,361

See accompanying notes to consolidated financial statements

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Operating activities		
Net loss	$ (2,024)	$ (50,050)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	21,797	19,827
Amortization of deferred financing costs	356	1,043
Deferred taxes	(56)	101
Unit-based compensation	761	479
Non-cash compensation associated with phantom units granted to officers	151	212
Amortization of premiums paid on derivative contracts	3,234	4,367
Amortization of value on derivative contracts acquired	—	52
Unrealized losses on commodity and interest rate derivative contracts	23,155	71,458
Loss on acquisition of oil and natural gas properties	330	—
Changes in operating assets and liabilities:		
Trade accounts receivable	(2,254)	(1,703)
Payables to affiliates	(42)	615
Other current assets	5	(851)
Price risk management activities, net	(59)	(475)
Accounts payable and oil and natural gas revenue payable	115	2,117
Accrued expenses and other liabilities	170	(2,350)
Other assets	436	4
Net cash provided by operating activities	46,075	44,846
Investing activities		
Additions to property and equipment	(120)	(244)
Additions to oil and natural gas properties	(8,213)	(3,454)
Acquisitions of oil and natural gas properties	(13,518)	(1,505)
Deposits and prepayments of oil and natural gas properties	(709)	(2,638)
Proceeds from the sale of oil and natural gas properties	5,377	—
Net cash used in investing activities	(17,183)	(7,841)
Financing activities		
Proceeds from borrowings	48,500	138,000
Repayment of debt	(179,500)	(145,500)
Proceeds from equity offering, net	136,904	—
Distributions to members	(31,723)	(16,848)
Financing costs	(680)	(121)
Prepaid offering costs	—	(75)
ENP distributions to non-controlling interest	—	(12,278)
Net cash used in financing activities	(26,499)	(36,822)

Net increase in cash and cash equivalents		2,393		183
Cash and cash equivalents, beginning of period		2,851		1,828
Cash and cash equivalents, end of period	$	5,244	$	2,011
Supplemental cash flow information:				
Cash paid for interest	$	4,891	$	5,577
Non-cash investing and financing activities:				
Common units received in exchange for Appalachian Basin properties	$	52,478		—
Asset retirement obligations	$	99	$	91
Deferred swap premium	$	4,863	$	—

See accompanying notes to consolidated financial statements

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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 quarterly cash distributions to our unitholders and, over time, increasing our quarterly 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 six operating areas:

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

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”). In February 2012, we entered into a Unit Exchange Agreement with our founding unitholder to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC which 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, $52.5 million, with an effective date of January 1, 2012 (the “Unit Exchange”). We completed this transaction on March 30, 2012 for total non-cash consideration of $51.1 million, after 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 in the current period 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, 2011 from the audited financial statements filed in our 2011 Annual Report. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles (“GAAP”). You should read this Quarterly Report on Form 10-Q along with our 2011 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. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income, members’ equity or net cash flows.

As of March 31, 2012, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2011 Annual Report.

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of March 31, 2012 and December 31, 2011 and for the three months ended March 31, 2012 and 2011 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) 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, 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.

(c) Non-controlling Interest:

On December 31, 2010, we acquired (the “ENP Purchase”) all of the member interests in Encore Energy Partners GP, LLC (“ENP GP”), the general partner of Encore Energy Partners LP (“ENP”), and 20,924,055 common units representing limited partnership interests in ENP (the “ENP Units”), together representing a 46.7% aggregate equity interest in ENP at the date of the ENP Purchase, from Denbury Resources Inc. (“Denbury”). Since the ENP Purchase, and prior to an internal reorganization whereby ENP GP and ENP were merged into VNG, we consolidated ENP as we had the ability to control the operating and financial decisions and policies of ENP through our ownership of ENP GP. As presented in the accompanying unaudited Consolidated Statements of Operations for the three months ended March 31, 2011, “net loss attributable to non-controlling interest” of $19.6 million, represents ENP's results of operations attributable to third-party owners other than Vanguard.

On December 1, 2011, we acquired the remaining 53.4% of the ENP Units not held by us through a merger (the “ENP Merger”) with one of our wholly owned subsidiaries. We refer to the ENP Purchase and ENP Merger collectively as the “ENP Acquisition.”

2. Acquisitions

On March 9, 2012, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Wyoming. We refer to this acquisition as the “Wyoming II Acquisition.” The purchase price for the assets was $13.5 million, subject to customary post-closing adjustments to be determined. We completed this acquisition on March 30, 2012 with an effective date of March 1, 2012. The purchase price was funded with borrowings under our Reserve-Based Credit Facility. In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Wyoming II Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, 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.

In accordance with ASC Topic 805, presented below are unaudited pro forma results for each of the three months ended March 31, 2012 and 2011 to show the effect on our consolidated results of operations as if the Wyoming II Acquisition had occurred on January 1, 2011and all of our acquisitions during 2011 as listed below had occurred on January 1, 2010. For a complete description of these acquisitions please refer to footnote 2 of our consolidated financial statements contained in our 2011 Annual Report.

Acquisition	Closing Date
Newfield Acquisition	May 12, 2011
Permian Basin Acquisition I	July 29, 2011
Permian Basin Acquisition II	August 8, 2011
Wyoming I Acquisition	September 1, 2011
Gulf Coast Acquisition	August 31, 2011
North Dakota Acquisition	December 1, 2011
Parker Creek II Acquisition	December 22, 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, 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, and (3) interest expense on additional borrowings necessary to finance the acquisitions. The unaudited pro forma results also reflect the impact of the Unit Exchange, including the elimination of the results of operations from the properties we previously owned in the Appalachian Basin and the receipt of the 1.9 million common units received as consideration for the exchange, as if it had occurred on January 1, 2011. The net gain (loss) on acquisition of oil and natural gas properties and material transactions costs related to the ENP Merger were excluded from the pro forma results for the three months ended March 31, 2012 and 2011. Additionally, the pro forma results are adjusted for the elimination of non-controlling interest in ENP for the three months ended March 31, 2011 and the impact of additional common units issued in connection with the ENP Merger. The pro forma information is based upon these assumptions and is not necessarily indicative of future results of operations:

	Pro forma (in thousands, except per unit data)			
	Three Months Ended March 31,			
	2012		2011	
Total revenues	$	53,855	$	8,865
Net loss	$	(1,307)	$	(46,234)
Net loss per unit:				
Common & Class B units – basic & diluted	$	(0.03)	$	(1.00)

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 (in thousands):

	Three Months Ended March 31,			
	2012		2011	
Revenues	$	3,267	$	4,983
Excess of revenues over direct operating expenses	$	382	$	1,481

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 (in thousands). Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes. The following acquisitions were completed subsequent to March 31, 2011 and therefore no operations were included during the first quarter of 2011.

	Three Months Ended March 31, 2012	
Newfield Acquisition		
Revenues	$	470
Excess of revenues over direct operating expenses	$	420
Permian Basin Acquisition I		
Revenues	$	4,382
Excess of revenues over direct operating expenses	$	3,258
Permian Basin Acquisition II		
Revenues	$	489
Excess of revenues over direct operating expenses	$	378
Wyoming I Acquisition		
Revenues	$	1,834
Excess of revenues over direct operating expenses	$	1,059
Gulf Coast Acquisition		
Revenues	$	3,152
Excess of revenues over direct operating expenses	$	1,719
North Dakota Acquisition		
Revenues	$	842
Excess of revenues over direct operating expenses	$	184
Parker Creek II Acquisition		
Revenues	$	539
Excess of revenues over direct operating expenses	$	470

Wyoming II Acquisition		
Revenues	$	8
Excess of revenues over direct operating expenses	$	8

3. Debt

Our financing arrangements consisted of the following:

Description	Interest Rate	Maturity Date	Amount Outstanding March 31, 2012	Amount Outstanding December 31, 2011
			(in thousands)	
Senior Secured Reserve-Based Credit Facility	Variable (1)	October 31, 2016	$ 583,000	$ 671,000
Second Lien Term Loan	Variable (2)	May 30, 2017	57,000	100,000
Total debt			$ 640,000	$ 771,000

(1) Variable interest rate was 2.50% and 2.55% at March 31, 2012 and December 31, 2011, respectively.
(2) Variable interest rate was 5.74% and 5.8% at March 31, 2012 and December 31, 2011, respectively.

Senior Secured Reserve-Based Credit Facility

On September 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the “Credit Agreement”) with a maximum facility size of $1.5 billion (the “Reserve-Based Credit Facility”) and an initial borrowing base of $765.0 million. The Credit Agreement provides for the (1) extension of the maturity date by five years to October 31, 2016, (2) increase in the number of lenders from eight to twenty, (3) increase in the percentage of future production that can be hedged, (4) increase in the permitted debt to EBITDA coverage ratio from 3.5x to 4.0x, (5) elimination of the required interest coverage ratio, (6) elimination of the ten percent liquidity requirement to pay distributions to unitholders, and (7) ability to incur unsecured debt. Borrowings from this Reserve-Based Credit Facility and the Second Lien Term Loan facility (as discussed below) were used to fully repay outstanding borrowings from the ENP’s senior secured revolving credit facility and Vanguard’s $175.0 million term loan. In November 2011, we entered into the First Amendment to the Third Amended and Restated Credit Agreement, which included amendments to (a) specify the effective date of November 30, 2011, (b) allow us to use the proceeds from our Reserve-Based Credit Facility to refinance our debt under the Second Lien Term Loan facility, (c) include the current maturities under the Second Lien Term Loan in determining the consolidated current ratio, and (d) provide a cap on the amount of outstanding debt under the Second Lien Term Loan. Our obligations under the Reserve-Based Credit Facility are secured by mortgages on our oil and natural gas properties and other assets and are guaranteed by all of our operating subsidiaries.

On March 30, 2012, the closing date of the Unit Exchange, our borrowing base was reduced to $740.0 million. On March 31, 2012 there were $583.0 million of outstanding borrowings and $157.0 million of borrowing capacity under the Reserve-Based Credit Facility. In April 2012, our borrowing base was further reduced to $670.0 as a result of the completion of our Senior Notes offering. Please 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, 2012, 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, 2012, 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.

Second Lien Term Loan

On November 30, 2011, we entered into a $100.0 million senior secured second lien term loan facility (the "Second Lien Term Loan") with seven banks that are lenders under the Reserve-Based Credit Facility, with a maturity date of May 30, 2017. Our obligations under the Second Lien Term Loan were secured by a second priority lien on all of our oil and natural gas properties and other assets and were guaranteed by all of our operating subsidiaries.

Borrowings under the Second Lien Term Loan were comprised entirely of Eurodollar Loans. Interest on borrowings under the Second Lien Term Loan was payable quarterly on the last day of each March, June, September and December and accrued at a rate per annum equal to the sum of the applicable margin plus the Adjusted LIBO Rate in effect on such day. The applicable margin increased based upon the number of days after the effective date of the Second Lien Term Loan as follows:

	Days after effective date		
	1-180	181-360	360+
Applicable Margin	5.50%	6.00%	8.50%

Our Second Lien Term Loan contained a number of customary covenants that required us to maintain certain financial ratios, limited 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, 2012, we were in compliance with all of our debt covenants. In April 2012, we paid all of our outstanding debt under the Second Lien Term Loan using the proceeds from our Senior Notes offering. Please see Note 12. Subsequent Events for further discussion.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our financing arrangements 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. Under fixed-priced commodity swap agreements, we receive a fixed price on a notional quantity in exchange for paying a variable price based on a market index. In addition, we sell calls, purchase puts or provide options to counterparties under swaption agreements to extend the swaps into subsequent years. Under put option agreements, we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. At settlement date, we receive the excess, if any, of the fixed floor over floating rate. We also enter into 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. Under collar contracts, we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor price on a notional quantity. Put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub, and collars are settled based on a market index selected by us at inception of the contract. We also may enter into 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 price 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. We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our financing arrangements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Under ASC Topic 815, "Derivatives and Hedging" ("ASC Topic 815"), all derivative instruments are recorded on the accompanying Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) in the equity section of the Consolidated Balance Sheets to the extent the hedge is effective. Gains and losses on cash flow hedges included in accumulated other comprehensive income (loss) are reclassified to gains (losses) on commodity cash flow hedges or gains (losses) on interest rate derivative contracts in the period that the related production is delivered or the contract settles. The realized and unrealized gains (losses) on derivative contracts that do not qualify for hedge accounting treatment are recorded as gains (losses) on commodity derivative contracts or gains (losses) on interest rate derivative contracts in the accompanying Consolidated Statements of Operations.

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.

As of March 31, 2012, we had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		Oil	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	WTI Price
April 1, 2012 – December 31, 2012	4,455,550	$ 5.51	1,117,875	$ 89.80
January 1, 2013 – December 31, 2013	7,738,000	$ 5.23	1,423,500	$ 89.17
January 1, 2014 – December 31, 2014	2,885,225	$ 5.24	1,414,375	$ 89.91

Swaptions

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

	Gas		Oil	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average Fixed Price
April 1, 2012 - December 31, 2012	—	—	103,125	$ 100.00
January 1, 2013 - December 31, 2013	—	—	196,350	$ 100.73
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

As of March 31, 2012, the Company had the following open basis swap contracts:

	Gas		Oil	
Contract Period	MMBtu	Weighted Avg. Basis	Bbls	Weighted Avg. Basis

			Differential (1)			Differential (2)
April 1, 2012 – December 31, 2012	687,500	$	(0.32)	63,000	$	15.15
January 1, 2013 – December 31, 2013	912,500	$	(0.32)	84,000	$	9.60
January 1, 2014 – December 31, 2014	452,500	$	(0.32)	—	$	—

(1) Natural gas basis swap contracts represent a weighted average differential between prices against Rocky Mountains (CIGC) and NYMEX Henry Hub prices.

(2) Oil basis swap contracts represent a weighted average differential between prices against Light Louisiana Sweet Crude (LLS) and NYMEX WTI prices.

Collars

		Oil	
Production Period	Bbls	Floor	Ceiling
April 1, 2012 - December 31, 2012	309,375	$ 80.89	$ 100.12
January 1, 2013 - December 31, 2013	82,125	$ 88.89	$ 107.34
January 1, 2014 - December 31, 2014	12,000	$ 100.00	$ 116.20

Three-Way Collars

		Oil		
Production Period	Bbls	Floor	Ceiling	Put Sold
April 1, 2012 - December 31, 2012	646,250	$ 88.94	$ 104.02	$ 69.36
January 1, 2013 - December 31, 2013	1,090,150	$ 94.26	$ 106.38	$ 69.37
January 1, 2014 - December 31, 2014	565,750	$ 98.06	$ 108.86	$ 74.19
January 1, 2015 - December 31, 2015	194,055	$ 100.00	$ 124.53	$ 75.00

Puts

	Gas	
Contract Period	MMBtu	Weighted Average Fixed Price
April 1, 2012 – December 31, 2012	246,950	$ 6.76

Put Spreads

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

Interest Rate Swaps

We enter into interest rate swap agreements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate exposures to fixed interest rates.

As of March 31, 2012, we had open interest rate derivative contracts as follows (in thousands):

Period	Notional Amount	Fixed Libor Rates
April 1, 2012 to December 10, 2014	$ 20,000	2.60%
April 1, 2012 to January 31, 2015	$ 40,000	1.75%
April 1, 2012 to January 31, 2015	$ 20,000	1.89%
April 1, 2012 to March 7, 2016	$ 75,000	1.08%

April 1, 2012 to September 23, 2016	$	75,000	1.15%
August 6, 2012 to August 6, 2014	$	25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$	30,000	2.25%
September 7, 2012 to September 7, 2016	$	25,000	1.25%

(1) The counterparty has the option to extend the termination date of this contract for a notional amount of $30.0 million at 2.25% to August 5, 2018. Additionally, we sold the option to a counterparty to put us into a $25,000 LIBOR swap at 1.25% for the period September 7, 2012 to September 7, 2016.

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 summarizes the fair value of derivatives outstanding on a gross basis (in thousands):

	March 31, 2012	December 31, 2011
Assets:		
Commodity derivatives	$ 64,022	$ 42,504
Interest rate swaps	381	504
	$ 64,403	$ 43,008
Liabilities:		
Commodity derivatives	$ (107,374)	$ (66,129)
Interest rate swaps	(7,066)	(6,768)
	$ (114,440)	$ (72,897)

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. 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 $64.4 million at March 31, 2012.

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 mitigated as of March 31, 2012.

Gain (Loss) on Derivatives

Gains and losses on derivatives that are not accounted for as cash flow hedges 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,	
	2012	2011
Realized gains (losses):		
Commodity derivatives	$ (3,239)	$ 1,379
Interest rate swaps	(576)	(893)
	$ (3,815)	$ 486

Unrealized gains (losses):				
Commodity derivatives	$	(22,734)	$	(72,560)
Interest rate swaps		(421)		1,102
	$	(23,155)	$	(71,458)
Total gains (losses):				
Commodity derivatives	$	(25,973)	$	(71,181)
Interest rate swaps		(997)		209
	$	(26,970)	$	(70,972)

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 fair value information about 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 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:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, payables to affiliates, accrued expenses and deferred swap premium liability. The carrying amounts approximate fair value due to the short maturity of these instruments.

Financing arrangements. The carrying amounts of our borrowings outstanding under Reserve-Based Credit Facility and Second Lien Term Loan 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.

Our commodity derivative instruments consist of fixed-price swaps, basis swaps, swaptions, put options, NYMEX collars and three-way collars. We estimate the fair values of the 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. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties' and our credit standing are used to discount future cash flows. We have classified the fair values of all of our derivative contracts as Level 2.

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

	March 31, 2012			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 2,447	$ —	$ 2,447
Interest rate derivative contracts	—	381	—	381
Total derivative instruments	$ —	$ 2,828	$ —	$ 2,828
Liabilities:				
Commodity price derivative contracts	$ —	$ (45,799)	$ —	$ (45,799)
Interest rate derivative contracts	—	(7,066)	—	(7,066)
Total derivative instruments	$ —	$ (52,865)	$ —	$ (52,865)

	December 31, 2011			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 3,438	$ —	$ 3,438
Interest rate derivative contracts	—	—	—	—
Total derivative instruments	$ —	$ 3,438	$ —	$ 3,438
Liabilities:				
Commodity price derivative contracts	$ —	$ (27,063)	$ —	$ (27,063)
Interest rate derivative contracts	—	(6,264)	—	(6,264)
Total derivative instruments	$ —	$ (33,327)	$ —	$ (33,327)

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 for the amount by which 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 decreases in the prices of oil and natural gas or any significant negative reserve adjustments from the December 31, 2011 assessment could change our estimates of the fair value of our reporting unit and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

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

	March 31, 2012		
	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Assets:			
Goodwill	$ —	$ —	$ 420,955
Other intangible assets, net	—	8,792	—

	December 31, 2011		
	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Assets:			
Goodwill	$ —	$ —	$ 420,955
Other intangible assets, net	—	8,837	—

Our nonfinancial assets and liabilities, which are initially measured at fair value, are comprised primarily of asset retirement costs and obligations. These assets and liabilities are recorded at fair value when 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. Asset Retirement Obligations, in accordance with ASC Topic 410-20. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate ranging between 5.0% and 5.5%; and (4) the 10-year average inflation factor (2.4%).

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 the three months ended March 31, were as follows (in thousands):

	2012	2011
Asset retirement obligations at January 1,	$ 35,920	$ 30,202
Liabilities added during the current period	195	91
Accretion expense	270	188
Retirements	(294)	—
Total asset retirement obligations at March 31,	36,091	30,481
Less: current obligations	(1,411)	(888)
Long-term asset retirement obligation at March 31,	$ 34,680	$ 29,593

7. Related Party Transactions

As discussed above, we previously owned oil and natural gas properties in the Appalachian Basin. In February 2012, we entered into a Unit Exchange Agreement with our founding unitholder to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC which 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, $52.5 million, with an effective date of January 1, 2012. We completed this transaction on March 30, 2012 for total non-cash consideration of $51.1 million, after closing adjustments of $1.4 million.

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 current natural gas and oil properties in the Appalachian Basin under a Management Services Agreement ("MSA") which costs are 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 $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis since then, 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 were $0.6 million and $0.4 million for the three months ended March 31, 2012 and 2011, respectively. Costs incurred under the GCA were $0.4 million and $0.5 million for the three months ended March 31, 2012 and 2011, respectively. As a result of the Unit Exchange, the MSA and GCA were terminated.

8. Commitments and Contingencies

The Company is a defendant in a legal proceeding 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 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.

On March 29, 2011, John O'Neal, a purported unitholder of ENP, filed a putative class action petition in the 125th Judicial District of Harris County, Texas on behalf of unitholders of ENP. Similar petitions were filed on April 4, 2011 by Jerry P. Morgan and on April 5, 2011 by Herbert F. Rower in other Harris County district courts. The O'Neal, Morgan, and Rower lawsuits were consolidated on June 5, 2011 as John O'Neal v. Encore Energy Partners, L.P., et al., Case Number 2011-19340, which is pending in the 125th Judicial District Court of Harris County. On July 28, 2011, Michael Gilas filed a class action petition in intervention. On July 26, 2011, the current plaintiffs in the consolidated O'Neal action filed an amended putative class action petition against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action petition and Gilas's petition in intervention both allege that the named defendants are (i) violating duties owed to ENP's public unitholders by, among other things, failing to properly value ENP and failing to protect against conflicts of interest or (ii) are aiding and abetting such breaches. Plaintiffs seek an injunction prohibiting the merger from going forward and compensatory damages if the merger is consummated. On October 3, 2011, the Court appointed Bull & Lifshitz, counsel for plaintiff-intervenor Gilas, as interim lead counsel on behalf of the putative class. On October 21, 2011, the court signed an order staying this lawsuit pending resolution of the Delaware State Court Action (defined below), subject to plaintiffs' right to seek to lift the stay for good cause. The defendants named in the Texas lawsuits intend to defend vigorously against them.

On April 5, 2011, Stephen Bushansky, a purported unitholder of ENP, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption In re: Encore Energy Partners LP Unitholder Litigation, C.A. No. 6347-VCP (the

"Delaware State Court Action"). On December 28, 2011, those plaintiffs jointly filed their second amended consolidated class action complaint naming as defendants ENP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action complaint alleges, among other things, that defendants breached the partnership agreement by recommending a transaction that is not fair and reasonable. Plaintiffs seek compensatory damages. Vanguard has filed a motion to dismiss this lawsuit and it intends to defend vigorously against this lawsuit.

On August 28, 2011, Herman Goldstein, a purported unitholder of ENP, filed a putative class action complaint against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard in the United States District Court for the Southern District of Texas on behalf of the unitholders of ENP. That lawsuit is captioned Goldstein v. Encore Energy Partners LP. et al., United States District Court for the Southern District of Texas, 4:11-cv-03198. Goldstein alleges that the named defendants violated Sections 14(a) and 20(a) of the Securities Exchange Act of 1934 as amended (the "Exchange Act") and Rule 14a-9 promulgated thereunder by disseminating a false and materially misleading proxy statement in connection with the merger. Plaintiff seeks an injunction prohibiting the proposed merger from going forward. Currently, the parties are awaiting the appointment of a lead plaintiff in this lawsuit. The defendants named in this lawsuit intend to defend vigorously against it.

On September 6, 2011, Donald A. Hysong, a purported unitholder of ENP, filed a putative class action complaint against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard on behalf of the unitholders of ENP in the United States District Court for the District of Delaware that is captioned Hysong v. Encore Energy Partners LP. et al., 1:11-cv-00781-SD. Hysong alleged that the named defendants violated either Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder or Section 20(a) of the Securities Exchange Act of 1934 by disseminating a false and materially misleading proxy statement in connection with the merger. On September 14, 2011, in accordance with recent practice in Delaware, that case was assigned to Judge Stewart Dalzell of the Eastern District of Pennsylvania. On November 10, 2011, Judge Dalzell entered an order dismissing the lawsuit and entering judgment in the defendants' favor.

Vanguard cannot predict the outcome of these or any other lawsuits that might be filed subsequent to the date of this filing, nor can Vanguard predict the amount of time and expense that will be required to resolve these lawsuits. Vanguard and the other defendants named in these lawsuits intend to defend vigorously against these and any other actions.

9. Common Units and Net Loss per Unit

Basic earnings per unit is computed in accordance with ASC Topic 260 "Earnings Per Share" ("ASC Topic 260") by dividing net income/(loss) attributable to Vanguard unitholders by the weighted average number of units outstanding during the period. Diluted earnings 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, 2012, we had two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on the New York Stock Exchange (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 earnings per unit.

For the three months ended March 31, 2012 and 2011, the 175,000 options granted to officers under the Vanguard Natural Resources, LLC Long-Term Incentive Plan (the "VNR LTIP") have been excluded in the computation of diluted earnings per unit as they had no dilutive effect. In addition, the 115,000 phantom units granted to officers under our long-term incentive plan had no dilutive effect on earnings per unit for the three months ended March 31, 2012 and 2011; therefore, they have been excluded in the computation of diluted earnings per unit.

In accordance with ASC Topic 260, dual presentation of basic and diluted earnings per unit has been presented in the Consolidated Statements of Operations for the three months ended March 31, 2012 and 2011 including each class of units issued and outstanding at that date: 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.

10. Unit-Based Compensation

In October 2007, two officers were granted options to purchase an aggregate of 175,000 units under the VNR LTIP with an exercise price equal to the initial public offering price of $19.00, which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant. These options expire on October 29, 2012. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718, "Compensation-Stock Compensation," by calculating the Black-Scholes value of each option, using a volatility rate of 12.18%, an expected dividend yield of 8.95% and a discount rate of 5.12%, and multiplying the Black-Scholes value by the number of options awarded. In determining a volatility rate of 12.18%, we, due to a lack of historical data regarding our common units, used the historical volatility of the Citigroup MLP Index over the 365 day period prior to the date of grant.

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 will continue until January 1, 2013, with 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. Also, 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 Amended Agreements provide for an annual base salary and include an annual bonus structure for the executives. 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 to be determined by our board of directors for the February Amended Agreements and by our Chief Executive Officer for the June Amended Agreement. Each of the three components will be weighted equally in calculating the respective executive officer’s annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two times the respective executive’s annual base salary. In addition, the Amended Agreements also provide for the executives to receive annual grants of restricted units and phantom units pursuant to the VNR LTIP.

During the three months ended March 31, 2012, two of our executives were granted 15,000 phantom units each under the February Amended Agreements. 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). As of March 31, 2012, an accrued liability of $0.2 million has been recorded and non-cash unit-based compensation expense of $0.2 million has been recognized in the selling, general and administrative expense line item in the Consolidated Statement of Operations for each of the three months ended March 31, 2012 and 2011.

During the three months ended March 31, 2012, VNR employees were granted a total of 23,413 common units which will vest equally over a four year period. In February 2012, one board member was granted 1,000 common units which will vest one year from the date of grant. All of these grants have distribution equivalent rights that provide the grantee with a payment equal to the distribution on unvested units.

These common units, options and phantom units were granted as partial consideration for services to be performed under employment contracts and thus will be subject to accounting for these grants under ASC Topic 718. 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, 2012 is presented below:

	Number of Non-vested Units		Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2011	366,670	$	27.92
Granted	24,413	$	27.71
Forfeited	(10,829)	$	27.82

Vested	(15,985)	$	25.32
Non-vested units at March 31, 2012	364,269	$	28.02

At March 31, 2012, there was approximately $7.2 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.5 years. Our accompanying Consolidated Statements of Operations reflect non-cash compensation of $0.9 million and $0.3 million in the selling, general and administrative expenses line item for the three months ended March 31, 2012 and 2011, 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. Also, 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. Net proceeds, terms and pricing of each offering of securities issued under the Shelf Registration Statements are determined at the time of such offerings. The Shelf Registration Statements does not provide assurance that we will or could sell any such securities. Our ability to utilize the Shelf Registration Statements for the purpose of offering, 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 having an aggregate offering price of up to $60.0 million. In accordance with the terms of the 2010 Distribution Agreement we may offer and sell up to the maximum dollar amount of our common units from time to time through our sales agent. Sales of the common units, if any, may be made by means of ordinary brokers' transactions through the facilities of the NYSE at market prices. Our sales agent will receive from us a commission of 1.25% based on the gross sales price per common unit for any common units sold through it as agent under the 2010 Distribution Agreement. Total net proceeds received under the 2010 Distribution Agreement through March 31, 2012 were approximately $6.3 million, after commissions, from the sales of 240,111 common units. Sales made pursuant to the 2010 Distribution Agreement were made through a prospectus supplement to our 2009 Shelf Registration Statement.

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, $115.0 million of the common units may be offered through a prospectus supplement to our 2009 Shelf Registration Statement. The additional $85.0 million of the common units may be offered pursuant to a new prospectus supplement to one of our existing effective shelf registration statements or a new shelf registration statement. Total net proceeds received under the 2011 Distribution Agreement through March 31, 2012, were approximately $2.5 million, after commissions, from the sales of 88,699 common units.

As a result of all our previous offerings, including those made under the 2010 and 2011 Distribution Agreements, we have approximately $113.7 million and $678.8 million remaining available as of March 31, 2012 under our 2009 and 2010 Shelf Registration Statements, respectively.

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. Net proceeds, terms and pricing of each offering of securities issued under the 2012 Shelf Registration Statement are determined at the time of such offerings. The 2012 Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the 2012 Shelf Registration Statement for the purpose of offering, 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 and the selling unitholder named therein.

In January 2012, we completed a public offering of 7,137,255 of our common units at a price of $27.71 per unit. The 7,137,255 common units offering included 4.0 million of our common units (“primary units”) and 3,137,255 common units (“secondary units”) offered by Denbury Onshore, LLC (“selling unitholder”). Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. The secondary units were obtained by the selling unitholder as partial consideration for the ENP Purchase. We received proceeds of approximately $106.1 million from the offering of primary units, after deducting underwriting discounts of $4.3 million and offering costs of $0.4 million. We did not receive any proceeds from the sale of the secondary units. In addition, we received proceeds of approximately $28.5 million, after deducting underwriting discounts of $1.2 million, from the sale of an additional 1,070,588 of our common units that were offered to the underwriters to cover over-allotments pursuant to this offering. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility and our Second Lien Term Loan.

In April 2012, we completed a public offering of $350.0 million aggregate principal amount of our 7.875% senior unsecured notes due 2020. Please see Note 12. Subsequent Events for further discussion.

12. Subsequent Events

Distributions

On April 24, 2012, our board of directors declared a cash distribution attributable to the first quarter of 2012 of $0.5925 per common unit expected to be paid on May 15, 2012 to Vanguard unitholders of record as of the close of business on May 8, 2012.

Senior Notes Due 2020

On April 4, 2012, we and our wholly-owned subsidiary, VNRF, 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 $339.6 million, after underwriting discounts and before expenses. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF) and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to release under certain of the following circumstances: (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 a default under the Indenture exists, none of the foregoing covenants will terminate.

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.

We used a portion of the net proceeds from this offering to repay all indebtedness outstanding under our Second Lien Term Loan and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility. Also, as a result of the completion of this offering, the borrowing base under our Reserve-Based Credit

Facility was reduced from $740.0 million to $670.0 million.

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 ("us," "we," "our," "the Company," "Vanguard" or "VNR"). The following discussion analyzes the financial condition and results of operations of Vanguard for the three months ended March 31, 2012 and 2011. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Vanguard in conjunction with our Annual Report on Form 10-K for the fiscal year ended December 31, 2011 (the "2011 Annual Report") and the historical unaudited condensed 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 quarterly cash distributions to our unitholders and, over time, increasing our quarterly 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 six operating areas:

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

As of March 31, 2012, based on internal reserve estimates, our total proved reserves were 71.9 MMBOE, of which approximately 62% were oil reserves, 27% were natural gas reserves and 11% were NGLs reserves. Of these total estimated proved reserves, approximately 87%, or 62.8 MMBOE, were classified as proved developed. Also, at March 31, 2012, we owned working interests in 3,997 gross (1,459 net) productive wells. Our operated wells accounted for approximately 69% of our total estimated proved reserves at March 31, 2012. Our average net daily production for the year ended December 31, 2011 and for the three months ended March 31, 2012 was 13,405 BOE/day and 13,569 BOE/day, respectively. Our average net production for the year ended December 31, 2011 includes production from the properties acquired in connection with the ENP Acquisition. Production from these properties during 2011 through the date of the completion of the ENP Merger on December 1, 2011 was subject to a 53.4% non-controlling interest in ENP. We own working interests ranging from 30% to 100% in approximately 42,468 gross undeveloped acres surrounding our existing wells. As of March 31, 2012, based on internal reserve estimates, approximately 13%, or 9.1 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 March 9, 2012, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Wyoming. We refer to this acquisition as the "Wyoming II Acquisition." The purchase price for the assets was $13.5 million, subject to customary post-closing adjustments to be determined. We completed this acquisition on March 30, 2012 with an effective date of March 1, 2012. The purchase price was funded with borrowings under our Reserve-Based Credit Facility. In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Wyoming II Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, 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.

Unit Exchange Agreement

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”). In February 2012, we entered into a Unit Exchange Agreement with our founding unitholder to transfer all our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC which 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, $52.5 million, with an effective date of January 1, 2012 (the “Unit Exchange”). We completed this transaction on March 30, 2012 for total non-cash consideration of $51.1 million, after closing adjustments of $1.4 million.

Senior Notes Due 2020

On April 4, 2012, we and our wholly-owned subsidiary, VNRF, 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 $339.6 million, after underwriting discounts and before expenses. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF) and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to release under certain of the following circumstances: (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 a default under the Indenture exists, none of the foregoing covenants will terminate.

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.

We used a portion of the net proceeds from this offering to repay all indebtedness outstanding under our Second Lien Term Loan, and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility. Also, as a result of the completion of this offering, our borrowing base under our Reserve-Based Credit Facility was reduced from $740.0 million to $670.0 million.

Outlook

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as 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 or natural gas 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 with oil price derivative contracts through 2015 and natural gas 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.

We 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 three months ended March 31, 2012, we drilled two gross (2.0 net) operated wells and two gross (0.2 net) non-operated wells. Our ability to add reserves 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 and 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 will not provide for the working capital necessary to fund our capital spending program and could affect our ability to make distributions.

Results of Operations

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

	Three Months Ended March 31, 2012 (a)	2011 (b)
Revenues:		
Oil sales	$ 64,403	$ 56,090
Natural gas sales	10,168	11,014
NGLs sales	8,146	4,935
Oil, natural gas and NGLs sales	82,717	72,039
Loss on commodity cash flow hedges	—	(1,071)
Realized gain (loss) on commodity derivative contracts	(3,239)	1,379
Unrealized loss on commodity derivative contracts	(22,734)	(72,560)
Total revenues	$ 56,744	$ (213)
Costs and expenses:		
Production:		
Lease operating expenses	$ 18,559	$ 12,332
Production taxes and marketing	6,860	6,222
Depreciation, depletion, amortization, and accretion	21,797	19,827
Selling, general and administrative expenses	4,972	4,876
Total costs and expenses	$ 52,188	$ 43,257
Other income (expense):		
Interest expense	$ (5,329)	$ (6,787)
Realized loss on interest rate derivative contracts	$ (576)	$ (893)
Unrealized gain (loss) on interest rate derivative contracts	$ (421)	$ 1,102
Loss on acquisition of oil and natural gas properties	$ (330)	$ —
Other	$ 76	$ (2)

(a)

The Wyoming II Acquisition closed on March 30, 2012, as such, no operations are included in the three month period ended March 31, 2012.

(b) The operating results of the subsidiaries we acquired in the ENP Purchase through the date of the completion of the ENP Merger on December 1, 2011 were subject to a 53.4% non-controlling interest.

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

Revenues

Oil, natural gas and NGLs sales increased $10.7 million to $82.7 million during the three months ended March 31, 2012 as compared to the same period in 2011. The key oil, natural gas and NGLs revenue measurements were as follows:

	Three Months Ended March 31,		Percentage Increase (Decrease)
	2012 (a)	2011 (b)	
Average realized prices (c):			
Oil (Price/Bbl)	$ 93.04	$ 81.81	14 %
Natural Gas (Price/Mcf)	$ 4.19	$ 4.36	(4) %
NGLs (Price/Bbl)	$ 59.08	$ 55.85	6 %
Combined (Price/BOE)	$ 66.99	$ 60.27	11 %
Total production volumes:			
Oil (Bbls)	692,173	685,047	1 %
Natural Gas (MMcf)	2,428	2,526	(4) %
NGLs (Bbls)	137,881	88,361	56 %
Combined (MBOE)	1,235	1,196	3 %
Average daily production volumes:			
Oil (Bbls/day)	7,606	7,611	—
Natural Gas (Mcf/day)	26,684	28,076	(5) %
NGLs (Bbls/day)	1,515	982	54 %
Combined (MBOE/day)	13,569	13,273	2 %

(a) The Wyoming II Acquisition closed on March 30, 2012, as such, no operations are included in the three month period ended March 31, 2012.
(b) Production from the properties acquired related to the ENP Purchase during 2011 through the date of the completion of the ENP Merger on December 1, 2011 was subject to a 53.4% non-controlling interest in ENP.
(c) Excludes results from hedging activities.

The increase in oil, natural gas and NGLs sales during the three months ended March 31, 2012 compared to the same period in 2011 was due primarily to the increases in production from our acquisitions that were completed during the second half of 2011 as well as increases in our realized commodity prices. Oil revenues increased 15% from $56.0 million in the first quarter of 2011 to $64.4 million in the first quarter of 2012 as a result of an $11.23 per Bbl increase in our average realized oil price, excluding hedges, and a 7.1 MBbls increase in our oil production volumes. Our higher average realized oil price was primarily due to a higher average NYMEX price, which increased from $94.25 per Bbl in the first quarter of 2011 to $102.93 per Bbl in the first quarter of 2012. Natural gas revenues decreased 8% from $11.0 million in the first quarter of 2011 to $10.2 million in the first quarter of 2012 as a result of a 4% decrease in our average realized natural gas price and in production volumes. NGLs sales increased 65% from $4.9 million in the first quarter of 2011 to $8.1 million in the first quarter of 2012 as a result of a $3.23 per Bbl increase in our average realized NGLs price and a 49.5 MBbls increase in our NGLs production volumes. Our higher NGLs sales was primarily due to production from the Permian Basin I and Wyoming I acquisitions completed during the second half of 2011. Additionally, our total production increased by 3% on a BOE basis. The increase in production for the three months ended March 31, 2012 over the comparable period in 2011 was primarily attributable to the impact from all of our acquisitions completed mostly during the second half of 2011. On a BOE basis, crude oil, natural gas, and NGLs accounted for 56%, 33% and 11%, respectively, of our production during the three months ended March 31, 2012 compared to crude oil, natural gas, and NGLs of 57%, 35% and 8%, respectively, during the same period in 2011.

Hedging and Price Risk Management Activities

During the three months ended March 31, 2012, we recognized a $3.2 million realized loss on commodity derivative contracts related to the settlements recognized during the period and a $22.7 million unrealized loss related to the change in fair value of derivative contracts that will settle in future periods that do not meet the criteria for cash flow hedge accounting. These realized and unrealized losses resulted from the changes in commodity prices and the effect of these price changes is discussed in the paragraph below. During the three months ended March 31, 2011, we recognized $1.1 million in losses on commodity cash flow hedges that previously met the criteria for cash flow hedge accounting. These amounts relate to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. They were later de-designated as cash flow hedges and the losses for the three months ended March 31, 2011 relate to amounts that settled in the respective periods which have been reclassified to earnings from accumulated other comprehensive loss.

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 the majority of our hedges are not designated 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 all 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 $6.2 million to $18.6 million for the three months ended March 31, 2012 as compared to the three months ended March 31, 2011, of which $2.7 million related to increased lease operating expenses for oil and natural gas properties acquired during 2011 and $1.9 million related to higher than anticipated costs for work in progress at year end 2011, resulting in an increase of costs in the current quarter activity. Additionally, the first quarter of 2011 lease operating expenses were lower than anticipated for work in progress at year end 2010 resulting in a $1.6 million offset to first quarter 2011 activity.

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 slightly by $0.6 million for the three months ended March 31, 2012 as compared to the same period in 2011. As a percentage of wellhead revenues, production, severance, and ad valorem taxes decreased slightly from 8.6% for the three months ended March 31, 2011 to 8.3% for the three months ended March 31, 2012.

Depreciation, depletion, amortization and accretion increased by approximately $2.0 million to $21.8 million for the three months ended March 31, 2012 from approximately $19.8 million for the three months ended March 31, 2011 primarily due to the increase in oil and natural gas properties related to acquisitions completed during the second half of 2011.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers salaries, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended March 31, 2012 remained relatively constant at $5.0 million compared to the $4.9 million during the three months ended March 31, 2011.

Other Income and Expense

Interest expense decreased to $5.3 million for the three months ended March 31, 2012 as compared to $6.8 million for the three months ended March 31, 2011 primarily due to lower average interest rates and lower average outstanding debt under our Reserve-Based Credit Facility during the three months ended March 31, 2012 compared to the same period in 2011.

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 its 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, 2012, our critical accounting policies were consistent with those discussed in our 2011 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 impairment tests 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.

Liquidity and Capital Resources

Overview

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and more recently the public equity and high yield 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 expect to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we will 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 May 1, 2012, we had $376.0 million available to be borrowed under our Reserve-Based Credit Facility.

The borrowing bases are 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 $670.0 million and the next scheduled redetermination is in October 2012. If commodity prices decline in the future and banks lower their internal projections of oil, natural gas and NGLs prices, it is possible that we will be subject to further 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 Facilities. 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 $46.1 million during the three months ended March 31, 2012, as compared to $44.8 million during the three months ended March 31, 2011.Changes in working capital decreased total cash flows by $1.6 million in 2012 as compared to $2.6 million in 2011. Contributing to the decrease in working capital during 2012 was a $2.3 million increase in accounts receivable resulting from the timing of collections, offset by a $0.4 million refund of prepaid drilling costs resulting from the change in operators for our Parker Creek wells and $0.3 million increase in accounts payable, oil and natural gas revenue payable and accrued expenses 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, 2012 or 2011.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and NGLs. 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, 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, puts, swaptions, NYMEX collars and three-way collars to reduce our exposure to the volatility in oil, natural gas and NGLs prices. See Note 4 in Notes to Consolidated Financial Statements and Part 1—Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk, for details about derivatives in place through 2015 for oil and through 2014 for natural gas.

Cash Flow from Investing Activities

Cash used in investing activities was approximately $17.2 million for the three months ended March 31, 2012, as compared to $7.8 million during the same period in 2011. 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 Wyoming II Acquisition and $0.7 million for deposits and prepayments related to the 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 Williston region. Cash used in investing activities in the first quarter of 2011 included $3.5 million for the drilling and development of oil and natural gas properties, $1.5 million for the acquisition of oil and natural gas properties and $2.6 million for prepayments for the drilling and development of oil and natural gas properties.

Cash Flow from Financing Activities

Cash used in financing activities was approximately $26.5 million for the three months ended March 31, 2012, as compared to $36.8 million for the three months ended March 31, 2011. Cash provided by financing activities during the three months ended March 31, 2012, included net proceeds from our public equity offering of $136.9, net of offering costs of $0.6 million. Additionally, cash of $131.0 million was used in the repayments of our financing arrangements and $31.7 million was used in distributions to unitholders. Cash used in financing activities during the three months ended March 31, 2011 included $7.5 million in net repayments under our financing arrangements. Additionally, cash of $16.8 million was used in distributions to unitholders and $12.3 million in ENP's distributions to non-controlling interest.

Debt and Credit Facilities

Reserve-Based Credit Facility

On September 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the "Credit Agreement") with a maximum facility amount of $1.5 billion (the "Reserve-Based Credit Facility") and an initial borrowing base of $765.0 million. This Credit Agreement provides for the (1) extension of the maturity date by five years maturing on October 31, 2016, (2) increase in the number of lenders from eight to twenty, (3) increase in the percentage of production that can be hedged into the future, (4) increase in the permitted debt to EBITDA coverage ratio from 3.5x to 4.0x, (5) elimination of the required interest coverage ratio, (6) elimination of the ten percent liquidity requirement to pay distributions to unitholders, and (7) ability to incur unsecured debt. Borrowings from the this Reserve-Based Credit Facility and the Second Lien Term Loan (as discussed below) were used to fully repay outstanding borrowings from ENP's senior secured revolving credit facility and Vanguard's $175.0 million term loan. In November 2011, we entered into the First Amendment to the Third Amended and Restated Credit Agreement, which included amendments to (a) specify the effective date of November 30, 2011, (b) allow us to use the proceeds from our facility to refinance our debt under the Second Lien Term Loan, (c) include the current maturities under the Second Lien Term Loan in determining the consolidated current ratio, and (d) provide a cap on the amount of outstanding debt under the Second Lien Term Loan.

At March 31, 2012, we had $583.0 million outstanding under our Reserve-Based Credit Facility and $157.0 million of borrowing capacity. 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. If commodity prices decline and banks lower their internal projections of oil, natural gas and NGLs prices, it is possible that we will be subject to decreases in our borrowing base availability in the future.

On March 30, 2012, the closing date of the Unit Exchange, our borrowing base was reduced to $740.0 million and in April 2012, our borrowing base was further reduced to $670.0 million as a result of the completion of our Senior Notes offering. As of May 1, 2012, we have $376.0 million available to be borrowed under our Reserve-Based Credit Facility.

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, 2012, we have 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, which includes the current portion of derivative contracts;

- 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 event of default.

We believe that we were in compliance with the terms of our Reserve-Based Credit Facility at March 31, 2012. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the 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 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.

Senior Secured Second Lien Term Loan

On November 30, 2011, we entered into a $100.0 million senior secured second lien term loan facility (the "Second Lien Term Loan") with seven banks from the Reserve-Based Credit Facility, with a maturity date of May 30, 2017.

Borrowings under the Second Lien Term Loan were comprised entirely of Eurodollar Loans. Interest on borrowings under the Second Lien Term Loan was payable quarterly on the last day of each March, June, September and December and accrued at a rate per annum equal to the sum of the applicable margin plus the Adjusted LIBO Rate in effect on such day. The applicable margin increased based upon the number of days after the effective date of the Second Lien Term Loan as follows:

	Days after effective date		
	1-180	181-360	360+
Applicable Margin	5.50%	6.00%	8.50%

Amounts outstanding under the Second Lien Term Loan were only be prepaid prior to maturity, together with all accrued and unpaid interest relating to the amount prepaid, when all outstanding borrowings under the Reserve-Based Credit Facility were paid in full except for mandatory prepayments related to any future equity and debt offerings. The Second Lien Term Loan contained principally the same covenants as our Reserve-Based Credit Facility, including restrictions on liens, restrictions on incurring other indebtedness without the lenders' consent and restrictions on entering into certain transactions. Amounts outstanding under the Second Lien Term Loan were secured by a second priority lien on all assets of VNG and its subsidiaries securing VNG's current Reserve-Based Credit Facility.

We believe that we were in compliance with the terms of our Second Lien Term Loan at March 31, 2012. In April 2012, we paid all our outstanding debt under the Second Lien Term Loan facility using the proceeds from our Senior Notes offering. Please see Note 12. Subsequent Events and “Item 2. Management’s Discussion and Analysis of FinancialCondition and Results of Operations—Recent Developments” for further discussion.

Senior Notes Due 2020

As discussed above, in April 2012, we completed a public offering of the Senior Notes. Please see Note 12. Subsequent Events and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments” for further discussion.

Off-Balance Sheet Arrangements

At March 31, 2012, 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 our pending litigation related to the ENP Merger as discussed in Part I, Item 3, Legal Proceedings in our 2011 Annual Report.

Commitments and Contractual Obligations

A summary of our contractual obligations as of March 31, 2012 is provided in the following table (in thousands):

	Payments Due by Year						
	2012	2013	2014	2015	2016	After 2016	Total
Management base salaries	$ 784	$ 116	$ —	$ —	$ —	$ —	$ 900
Asset retirement obligations (1)	983	1,755	674	563	2,765	29,351	36,091
Derivative liabilities (2)	31,279	42,985	26,445	9,908	3,823	—	114,440
Financing arrangements (3)	—	—	—	—	583,000	57,000	640,000
Operating leases	414	204	215	195	—	—	1,028
Development commitments (4)	2,150	—	—	—	—	—	2,150
Total	$ 35,610	$ 45,060	$ 27,334	$ 10,666	$ 589,588	$ 86,351	$ 794,609

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and the decommissioning of our Elk Basin gas plant. Please read Note 6 of the Notes to the Consolidated Financial Statements included in Item 1. Unaudited 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 "Item 3—Quantitative and Qualitative Disclosures About Market Risk" and Note 4 of the Notes to the Consolidated Financial Statements included in Item 1. Unaudited 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 principal balances shown as the interest rates on our financing arrangements are variable. Please read Note 3 of the Notes to the Consolidated Financial Statements included in Item 1. Unaudited Financial Statements for additional information regarding our long-term debt.

(4) Represents authorized purchases for work in process.

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net loss attributable to Vanguard unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net loss attributable to Vanguard unitholders plus, for 2011, net loss attributable to the non-controlling interest. The result is net loss which includes the non-controlling interest for 2011. From this we add or subtract the following:

- 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 losses on commodity and interest rate derivative contracts;
- Net gains and losses on acquisition of oil and natural gas properties;
- Deferred taxes;
- Unit-based compensation expense;
- Unrealized fair value of phantom units granted to officers;
- Material transaction costs incurred on acquisitions and mergers;
- For 2011, non-controlling interest amounts attributable to each of the items above which revert the calculation back to an amount attributable to the Vanguard unitholders; and
- For 2011, administrative services fees charged to ENP, excluding the non-controlling interest, which are eliminated in consolidation.

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

For the three months ended March 31, 2012 as compared to the three months ended March 31, 2011, Adjusted EBITDA attributable to Vanguard unitholders increased 42%, from $37.6 million to $53.2 million. The following table presents a reconciliation of consolidated net loss to Adjusted EBITDA (in thousands):

	Three Months Ended

	March 31,	
	2012	2011
Net loss attributable to Vanguard unitholders	$ (2,024)	$ (30,412)
Net loss attributable to non-controlling interest	—	(19,638)
Net loss	(2,024)	(50,050)
Plus:		
Interest expense, including realized losses on interest rate derivative contracts	5,905	7,680
Depreciation, depletion, amortization and accretion	21,797	19,827
Amortization of premiums paid on derivative contracts	3,234	4,367
Amortization of value on derivative contracts acquired	—	52
Unrealized losses on commodity and interest rate derivative contracts	23,155	71,458
Loss on acquisition of oil and natural gas properties	330	—
Deferred taxes	(70)	112
Unit-based compensation expense	761	479
Unrealized fair value of phantom units granted to officers	151	212
Adjusted EBITDA before non-controlling interest	53,239	54,137
Non-controlling interest attributable to adjustments above	—	(17,260)
Administrative services fees eliminated in consolidation	—	740
Adjusted EBITDA attributable to Vanguard unitholders	$ 53,239	$ 37,617

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 overhedged volumes.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, natural gas and NGLs production. Our realized pricing for oil production is primarily driven by the West Texas Intermediate Light Sweet, Louisiana Light Sweet, Flint Hills Bow River and Imperial Bow River prices. As for natural gas production, our realized pricing is primarily driven by the Henry Hub, Houston Ship Channel, West Texas ("Waha Index"), El Paso Natural Gas Company (Permian Basin) and Colorado Interstate Gas Company (Rocky Mountains) 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 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 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. These transactions may include price swaps whereby we will receive a fixed-price for our production and pay a variable market price to the contract counterparty. Additionally, we may acquire put options for which we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. As each monthly contract settles, we receive the excess, if any, of the fixed floor over the floating rate. We also enter into 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. Furthermore, we may enter into collars where we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor on a notional quantity. We also may enter into 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. We also enter into swaption agreements, under which we provide options to counterparties to extend swap contracts into subsequent years. 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. Typically, management intends to hedge 75% to 85% of projected 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. 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, 2012, the fair value of commodity derivative contracts was a liability of approximately $43.4 million, of which $14.3 million settles during the next twelve months.

The following table summarizes commodity derivative contracts in place at March 31, 2012:

	April 1, - December 31, 2012	Year 2013	Year 2014	Year 2015
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	4,455,550	7,738,000	2,885,225	—
Fixed Price ($/MMBtu)	$ 5.51	$ 5.23	$ 5.24	$ —
Puts:				
Notional Volume (MMBtu)	246,950	—	—	—
Fixed Price ($/MMBtu)	$ 6.76	$ —	$ —	$ —
Total Gas Positions:				
Notional Volume (MMBtu)	4,702,500	7,738,000	2,885,225	—
Floor Price ($/MMBtu)	$ 5.57	$ 5.23	$ 5.24	$ —

	April 1, - December 31, 2012	Year 2013	Year 2014	Year 2015
Oil Positions:				
Fixed Price Swaps:				
Notional Volume (Bbls)	1,117,875	1,423,500	1,414,375	—
Fixed Price ($/Bbl)	$ 89.80	$ 89.17	$ 89.91	$ —
Collars:				
Notional Volume (Bbls)	309,375	82,125	12,000	—
Floor Price ($/Bbl)	$ 80.89	$ 88.89	$ 100.00	$ —
Ceiling Price ($/Bbl)	$ 100.12	$ 107.34	$ 116.20	$ —
Three-Way Collars:				
Notional Volume (Bbls)	646,250	1,090,150	565,750	194,055
Floor Price ($/Bbl)	$ 88.94	$ 94.26	$ 98.06	$ 100.00
Ceiling Price ($/Bbl)	$ 104.02	$ 106.38	$ 108.86	$ 124.53
Put Sold ($/Bbl)	$ 69.36	$ 69.37	$ 74.19	75.00
Put Spreads:				
Notional Volume (Bbls)	—	—	—	255,500
Floor Price ($/Bbl)	$ —	$ —	$ —	$ 100.00
Put Sold ($/Bbl)	$ —	$ —	$ —	$ 75.00
Total Oil Positions:				
Notional Volume (Bbls)	2,073,500	2,595,775	1,992,125	449,555
Floor Price ($/Bbl)	$ 88.20	$ 91.30	$ 92.29	$ 100.00

As of March 31, 2012, the Company had the following open basis swap contracts:

	April 1, - December 31, 2012	Year 2013	Year 2014
Gas Positions:			
Notional Volume (MMBtu)	687,500	912,500	452,500
Weighted Avg. Basis Differential ($/MMBtu)(1)	$ (0.32)	$ (0.32)	$ (0.32)

Oil Positions:						
Notional Volume (Bbls)		63,000		84,000		—
Weighted Avg. Basis Differential ($/Bbl) (2)	$	15.15	$	9.60	$	—

(1) Natural gas basis swap contracts represent a weighted average differential between prices against Rocky Mountains (CIGC) and NYMEX Henry Hub prices

(2) Oil basis swap contracts represent a weighted average differential between prices against Light Louisiana Sweet Crude (LLS) and NYMEX WTI prices

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

	April 1, - December 31, 2012	Year 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)	103,125	196,350	492,750	508,445	622,200
Weighted Average Fixed Price ($/Bbl)	$ 100.00	$ 100.73	$ 117.22	$ 105.98	$ 125.00

Interest Rate Risks

At March 31, 2012, we had debt outstanding of $640.0 million. The amount outstanding under our Reserve-Based Credit Facility at March 31, 2012 of $583.0 million 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 $66 thousand increase in annual interest expense after consideration of the interest rate swaps discussed below. There was no interest rate derivatives hedging the interest rates associated with the amount outstanding under our Second Lien Term Loan at March 31, 2012 of $57.0 million.

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, 2012 (in thousands):

	April 1, - December 31, 2012	2013	2014	2015 (1)	2016
Weighted Average Notional Amount	$ 270,145	$ 310,000	$ 298,781	$ 197,932	$ 114,325
Weighted Average Fixed LIBOR Rate	1.49 %	1.54 %	1.52 %	1.24 %	1.16 %

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018. Additionally, we sold the option to a counterparty to put us into a $25,000 LIBOR swap at 1.25% beginning September 7, 2012 through September 7, 2016.

Counterparty Risk

At March 31, 2012, 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, 2012
Citibank, N.A. (A)	$ —	$ 999	$ (63)	$ —	$ 936
Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA-)	—	438	(5,773)	(4,785)	(10,120)
BNP Paribas (AA-)	—	—	(1,660)	(12,274)	(13,934)
The Bank of Nova Scotia (AA-)	381	—	(2,102)	(6,148)	(7,869)
BBVA Compass (A-)	—	—	—	(491)	(491)
Credit Agricole (A)	—	—	(7,202)	(4,564)	(11,766)
Royal Bank of Canada (AA-)	—	—	(81)	(6,493)	(6,574)
Natixis (A)	405	—	—	(34)	371
Bank of Montreal (A+)	—	57	(49)	—	8
Canadian Imperial Bank of Commerce (A+)	—	—	(129)	(68)	(197)
Barclays (A+)	—	547	—	—	547
Bank of America (A)	—	—	(230)	(718)	(948)
Total	$ 786	$ 2,041	$ (17,289)	$ (35,575)	$ (50,037)

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 Securities Exchange Act of 1934, as amended (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 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, 2012 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 fiscal quarter of 2012 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

The Company is a defendant 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 any action will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow. There have been no material developments regarding our pending litigation related to the ENP Merger as discussed in Part I, Item 3, Legal Proceedings in our 2011 Annual Report. 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.

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 2011 Annual Report, as supplemented by the risk factors set forth below. There have been no material changes to the risk factors set forth in our 2011 Annual Report, other than those set forth below.

Our financing arrangements have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations.

Our Reserve-Based Credit Facility and the Senior Notes contain certain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates, as well as containing covenants requiring us to maintain certain financial ratios and tests.

Our borrowing base is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will re-determine the borrowing base based on an engineering report with respect to our oil, natural gas and NGLs reserves, which will take into account the prevailing oil, natural gas and NGLs prices at such time. In the future, we may not be able to access adequate funding under our Reserve-Based Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations.

A future decline in commodity prices could result in a redetermination lowering our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our financing arrangements. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our Reserve-Based Credit Facility.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Reserve-Based Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Recently approved final rules regulating air emissions from natural gas production operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On April 17, 2012, the Environmental Protection Agency (“EPA”) approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. We are currently reviewing this new rule and assessing its potential impacts. Compliance with these requirements could increase our costs of development and production, though we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

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
1.1	Amendment No. 1 to Amended and Restated Equity Distribution Agreement, dated December 2, 2011, by and among Vanguard Natural Resources, LLC and Knight Capital Americas, L.P.	Filed herewith
1.2	Amendment No. 2 to Amended and Restated Equity Distribution Agreement, dated March 5, 2012, by and among Vanguard Natural Resources, LLC and Knight Capital Americas, L.P.	Filed herewith
1.3	Underwriting Agreement dated January 19, 2012, by and among Vanguard Natural Resources, LLC, Denbury Onshore, LLC, certain subsidiaries party thereto and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., UBS Securities LLC and RBC Capital Markets, LLC, as representatives of the several underwriters named therein	Form 8-K, filed January 24, 2012 (File No. 001-33756)
1.4	Underwriting Agreement dated March 30, 2012, by and among Vanguard Natural Resources, LLC, VNR Finance Corp., the subsidiary guarantors party thereto and Citigroup Global Markets Inc. and Credit Agricole Securities (USA) Inc., as representatives of the several underwriters named therein	Form 8-K, filed April 4, 2012 (File No. 001-33756)
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,	Form 8-K, filed November 2, 2007 (File No. 001-33756)

	LLC (including specimen unit certificate for the units)	
10.1	Unit Exchange Agreement, dated February 21, 2012, among Vanguard Natural Gas, LLC and Vanguard Natural Resources, LLC, and Majeed S. Nami Personal Endowment Trust and Majeed S. Nami Irrevocable Trust	Form 8-K, filed February 29, 2012 (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	Filed 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	Filed herewith

SIGNATURES

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

VANGUARD
NATURAL
RESOURCES, LLC
(Registrant)

Date: May 4, 2012

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