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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2011
OR
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 001-33756

Vanguard Natural Resources, LLC

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (832) 327-2255

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No
Common units outstanding on May 12, 2011: 29,784,749.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
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GLOSSARY OF TERMS

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

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

When we refer to oil, natural gas and natural gas liquids in “equivalents,” we are doing so to compare quantities of natural gas liquids 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 natural gas liquids and one Bbl of oil or one Bbl of natural gas liquids 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 (1) “us,” “we,” “our,” “the Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG”), Trust Energy Company, LLC (“TEC”), VNR Holdings, LLC (“VNRH”), Ariana Energy, LLC (“Ariana Energy”), Vanguard Permian, LLC (“Vanguard Permian”), VNR Finance Corp. (“VNRF”), Encore Energy Partners GP LLC (“ENP GP”), Encore Energy Partners LP (“ENP”), Encore Energy Partners Operating LLC (“OLLC”), Encore Energy Partners Finance Corporation (“ENPF”), Encore Clear Fork Pipeline LLC (“ECFP”) and (2) “Vanguard Predecessor,” “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Revenues:		
Oil, natural gas and natural gas liquids sales	$ 72,039	$ 20,070
Loss on commodity cash flow hedges	(1,071)	(1,042)
Realized gain on other commodity derivative contracts	1,379	5,214
Unrealized gain (loss) on other commodity derivative contracts	(72,560)	10,810
Total revenues	(213)	35,052
Costs and expenses:		
Production:		
Lease operating expenses	12,900	4,073
Production taxes and marketing	6,222	1,582
Depreciation, depletion, amortization, and accretion	19,827	4,238
Selling, general and administrative expenses	4,308	1,400
Total costs and expenses	43,257	11,293
Income (loss) from operations	(43,470)	23,759
Other income and (expense):		
Interest expense	(6,787)	(1,291)
Realized loss on interest rate derivative contracts	(893)	(515)
Unrealized gain (loss) on interest rate derivative contracts	1,102	(250)
Other	(2)	—
Total other expense	(6,580)	(2,056)
Net income (loss)	(50,050)	21,703
Less:		
Net loss attributable to non-controlling interest	(19,638)	—
Net income (loss) attributable to Vanguard unitholders	$ (30,412)	$ 21,703
Net income (loss) per Common and Class B units – basic & diluted	$ (1.01)	$ 1.15
Weighted average units outstanding:		
Common units – basic	29,725	18,416
Common units – diluted	29,725	18,483
Class B units – basic & diluted	420	420

See accompanying notes to consolidated financial statements

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

	March 31, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 2,011	$ 1,828
Accounts receivable, net	34,664	32,961
Derivative assets	4,966	16,523
Other current assets	2,316	1,474
Total current assets	43,957	52,786
Oil and natural gas properties, at cost	1,317,572	1,312,107
Accumulated depletion	(268,241)	(248,704)
Oil and natural gas properties evaluated, net – full cost method	1,049,331	1,063,403
Other assets		
Goodwill	420,955	420,955
Other intangible assets, net	8,972	9,017
Derivative assets	469	1,479
Deferred financing costs	4,727	5,649
Other assets	4,288	1,903
Total assets	$1,532,699	$ 1,555,192
Liabilities and members' equity		
Current liabilities		
Accounts payable		
Trade	$ 5,394	$ 3,156
Affiliate	1,283	668
Accrued liabilities:		
Lease operating	5,240	5,156
Developmental capital	2,558	996
Interest	482	310
Production taxes and marketing	13,207	11,793
Derivative liabilities	22,053	6,209
Deferred swap premium liability	1,325	1,739
Oil and natural gas revenue payable	2,120	2,241
Other	2,968	8,202
Current portion, long-term debt	399,000	175,000
Total current liabilities	455,630	215,470
Long-term debt	179,000	410,500
Derivative liabilities	76,757	30,384
Asset retirement obligations, net of current portion	29,593	29,434
Other long term liabilities	82	11
Total liabilities	741,062	685,799
Commitments and contingencies		
Members' equity		
Members' capital, 29,770,627 common units issued and outstanding at March 31, 2011 and 29,666,039 at December 31, 2010	271,960	318,597
Class B units, 420,000 issued and outstanding at March 31, 2011 and December 31, 2010	4,931	5,166
Accumulated other comprehensive loss	(2,000)	(3,032)
Total VNR members' equity	274,891	320,731
Non-controlling interest in subsidiary	516,746	548,662
Total members' equity	791,637	869,393
Total liabilities and members' equity	$1,532,699	$ 1,555,192

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, 2011 AND THE YEAR ENDED DECEMBER 31, 2010
(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 January 1, 2010	18,416	$ 59,873	420	$ 5,930	$ (5,517)	$ —	$ 60,286
Distributions to members ($0.525 per unit to unitholders of record February 5, 2010 and May 7, 2010 and $0.55 per unit to unitholders of record August 6, 2010 and November 5, 2010, respectively)	—	(45,747)	—	(903)	—	—	(46,650)
Issuance of common units, net of offering costs of $530	8,263	193,541	—	—	—	—	193,541
Issuance of common units in connection with Encore Acquisition	3,137	93,020	—	—	—	—	93,020
Redemption of common units	(150)	(3,651)	—	—	—	—	(3,651)
Unit-based compensation	—	(324)	—	139	—	—	(185)
Net income	—	21,885	—	—	—	—	21,885
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	2,485	—	2,485
Non-controlling interest in subsidiary	—	—	—	—	—	548,662	548,662
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)	—	(16,613)	—	(235)	—	—	(16,848)
Reduction of equity proceeds for offering costs	—	(91)	—	—	—	—	(91)

Unit-based compensation	105	479	—	—	—	—	479
Net loss	—	(30,412)	—	—	—	(19,638)	(50,050)
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	1,032	—	1,032
ENP cash distributions to non-controlling interest	—	—	—	—	—	(12,278)	(12,278)
Balance at March 31, 2011	29,771	$ 271,960	420	$ 4,931	$ (2,000)	$ 516,746	$ 791,637

See accompanying notes to consolidated financial statements

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Operating activities		
Net income (loss)	$ (50,050)	$ 21,703
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	19,827	4,238
Amortization of deferred financing costs	1,043	291
Unit-based compensation	479	254
Non-cash compensation associated with phantom units granted to officers	212	27
Amortization of premiums paid on derivative contracts	4,367	505
Amortization of value on derivative contracts acquired	52	610
Unrealized losses on other commodity and interest rate derivative contracts	71,458	(10,560)
Deferred taxes	101	—
Changes in operating assets and liabilities:		
Trade accounts receivable	(1,703)	(852)
Other receivables	—	353
Payables to affiliates	615	(212)
Other current assets	(851)	(15)
Price risk management activities, net	(475)	(46)
Accounts payable and oil and natural gas revenue payable	2,117	(392)
Accrued expenses and other current liabilities	(2,350)	(3,721)
Other assets	4	(80)
Net cash provided by operating activities	44,846	12,103
Investing activities		
Additions to property and equipment	(244)	(26)
Additions to oil and natural gas properties	(3,454)	(1,594)
Acquisitions of oil and natural gas properties	(1,505)	—
Deposits and prepayments of oil and natural gas properties	(2,638)	(1,067)
Net cash used in investing activities	(7,841)	(2,687)
Financing activities		
Proceeds from borrowings	138,000	16,400
Repayment of debt	(145,500)	(15,000)
Distributions to members	(16,848)	(9,889)
Offering costs	(75)	(23)
Financing costs	(121)	—
Purchase of units for issuance as unit-based compensation	—	(1,215)
ENP distributions to non-controlling interest	(12,278)	—
Net cash provided by financing activities	(36,822)	(9,727)
Net increase (decrease) in cash and cash equivalents	183	(311)
Cash and cash equivalents, beginning of period	1,828	487
Cash and cash equivalents, end of period	$ 2,011	$ 176
Supplemental cash flow information:		
Cash paid for interest	$ 5,577	$ 958

See accompanying notes to consolidated financial statements

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

	Three Months Ended March 31,	
	2011	**2010**
Net income (loss)	$ (50,050)	$ 21,703
Net gains from derivative contracts:		
Reclassification adjustments for settlements	1,032	996
Other comprehensive income	1,032	996
Comprehensive income (loss)	$ (49,018)	$ 22,699

See accompanying notes to consolidated financial statements

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. We own a 100% controlling interest, through certain of our subsidiaries, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- south Texas;
- the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee; and
- Mississippi.

In addition, we own an approximate 46.6% aggregate controlling interest through our subsidiary, ENP, in properties and oil and natural gas reserves located in four operating areas:

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

References in this report to (1) “us,” “we,” “our,” “the Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC (“TEC”), VNR Holdings, Inc. (“VNRH”), Ariana Energy, LLC (“Ariana Energy”), Vanguard Permian, LLC (“Vanguard Permian”) and VNR Finance Corp. (“VNRF”) and (2) “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

We were formed in October 2006 but effective January 5, 2007, Vanguard Natural Gas, LLC (formerly Nami Holding Company, LLC) was separated into our operating subsidiary and Vinland Energy Eastern, LLC ("Vinland"). As part of the separation, we retained all of our Predecessor’s proved producing wells and associated reserves. We also retained 40% of our Predecessor’s working interest in the known producing horizons in approximately 95,000 gross undeveloped acres and a contract right to receive approximately 99% of the net proceeds from the sale of production from certain producing gas and oil wells. In the separation, Vinland was conveyed the remaining 60% of our Predecessor’s working interest in the known producing horizons in this acreage, 100% of our Predecessor’s working interest in depths above and 100 feet below our known producing horizons. Vinland operates all of our existing wells in Appalachia and all of the wells that we drill in Appalachia.

On December 31, 2010, we completed an acquisition pursuant to a purchase agreement with Denbury Resources Inc. (“Denbury”), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the “Selling Parties” and, together with Denbury, the “Selling Parties”) to acquire (the “Encore Acquisition” or “Encore”) all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the “ENP Units”), representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. (“Encore Operating”), OLLC and Denbury (the “Services Agreement”). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG will provide certain general and administrative services to ENP, ENP GP and OLLC (collectively, the “ENP Group”) in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group’s total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the “Administrative Fee”). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement.

On March 24, 2011, VNR delivered a formal proposal to the chairman of the Conflicts Committee (the "Conflicts Committee") of ENP GP, the general partner of ENP, to acquire all of the outstanding common units of ENP, for consideration of 0.72 common unit of VNR for each outstanding common unit of ENP in a transaction to be structured as a merger of ENP with VNG. The Conflicts Committee of ENP GP has retained Bracewell & Giuliani as legal advisors and Jefferies & Company as financial advisors to assist in the evaluation of the proposal from VNR. The proposal of VNR is subject to customary terms and conditions, including applicable board and special committee approvals and the negotiation of definitive agreements. The Conflicts Committee of ENP GP is currently considering the proposal.

The fair value of the assets and liabilities we acquired on December 31, 2010 in the Encore Acquisition and cash flows associated with the transaction were included in the consolidated balance sheet as of December 31, 2010. We have consolidated ENP's accounts since December 31, 2010, the acquisition date. See Note 2, *Acquisitions*, for additional information.

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, 2010, from the audited financial statements filed in our 2010 Annual Report on Form 10-K. 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 2010 Annual Report on Form 10-K, 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, 2011, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2010 Annual Report on Form 10-K.

(a) ***Basis of Presentation and Principles of Consolidation:***

The consolidated financial statements as of March 31, 2011 and December 31, 2010 and for the three months ended March 31, 2011 and 2010 include our accounts and those of our wholly owned 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 natural gas liquids 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 natural gas liquids 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:***

As of March 31, 2011, Vanguard owned approximately 46.6% of ENP's outstanding common units. Vanguard also owns 100% of ENP GP, which is ENP's general partner. Since December 31, 2010, the acquisition date, we consolidated ENP as we have the ability to control the operating and financial decisions and policies of ENP through our ownership of ENP GP and reflected the non-controlling interest as a separate element of members' equity on our consolidated balance sheet. As presented in the accompanying unaudited consolidated balance sheet as of March 31, 2011, the $516.7 million of "non-controlling interest" represents third-party ownership interests other than Vanguard's in ENP. As presented in the accompanying unaudited consolidated statement 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.

2. Acquisitions

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the "Parker Creek Acquisition." The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 equity offering and with borrowings under the Company's existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel.

In accordance with the guidance contained within Accounting Standards Codification ("ASC") Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Parker Creek Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in goodwill of $5.7 million, which was immediately impaired and recorded as a loss. The loss resulted from a decrease in oil prices used to value the reserves.

On November 16, 2010, we entered into a Purchase Agreement with the Selling Parties to acquire all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP, representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010. We completed this acquisition on December 31, 2010. The acquisition was accounted for under the acquisition method of accounting in accordance with ASC 805 relating to "Business Combinations", which requires the assets and liabilities acquired be recorded at their fair values at the date of acquisition. The estimate of fair values resulted in goodwill of $421.0 million, which was recorded in the consolidated balance sheet at December 31, 2010.

The following unaudited pro forma results for the three months ended March 31, 2010 show the effect on our consolidated results of operations as if the Parker Creek and the Encore Acquisitions had occurred on January 1, 2010. 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) assumption of asset retirement obligations and accretion expense for the properties acquired, (2) the conversion of Encore's method of accounting for oil and natural gas properties from the successful efforts method of accounting to the full cost method of accounting, (3) depletion expense applied to the adjusted basis of the properties acquired, (4) interest expense on additional borrowings necessary to finance the acquisitions, (5) the impact of additional common units issued in connection with our 2010 equity offering completed at the time of the Parker Creek Acquisition, (6) the impact of additional common units issued in connection with the Encore Acquisition and (7) the allocation of Encore's pro forma net income to the non-controlling interest of Encore. The pro forma information is based upon these assumptions, and is not necessarily indicative of future results of operations (in thousands):

	Pro forma (in thousands, except per unit data)
	Three Months Ended March 31,2010
Total revenues	$ 93,394
Net income	$ 36,361
Net income attributable to non-controlling interest	$ 6,432
Net income attributable to VNR	$ 29,928
Net income per unit:	
Common & Class B units – basic & diluted	$ 1.19

The amount of revenues and excess of revenues over direct operating expenses included in our 2011 consolidated statements of operations for the Parker Creek Acquisition 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.

	Three Months Ended March 31, 2011
Parker Creek	
Revenues	$ 4,857
Excess of revenues over direct operating expenses	$ 4,043

The amount of revenues and earnings included in our 2011 consolidated statements of operations for the Encore Acquisition are shown in the table that follows (in thousands).

	Three Months Ended March 31, 2011
ENP	
Oil, natural gas and natural liquids revenues	$ 47,199
Net loss	$ (36,775)

3. Debt

Our financing arrangements consisted of the following:

Description	Interest Rate	Maturity Date	Amount Outstanding March 31, 2011	Amount Outstanding December 31, 2010
			(in thousands)	
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 179,000	$ 176,500
Term Loan	Variable (2)	December 31, 2011	175,000	175,000
ENP's credit agreement	Variable (3)	March 7, 2012	224,000	234,000
Total debt			578,000	585,500
Less: current obligations			(399,000)	(175,000)
Total long term debt			$ 179,000	$ 410,500

(1) Variable interest rate was 3.0% at March 31, 2011 and December 31, 2010, respectively.
(2) Variable interest rate was 5.75% and 5.77% at March 31, 2011 and December 31, 2010.
(3) Weighted average interest rate was 2.8% at March 31, 2011 and December 31, 2010.

Senior Secured Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. Also in November 2010, in connection with the Encore Acquisition, we entered into the Third Amendment to the Second Amended and Restated Credit Agreement to provide for certain amendments and modifications to allow us to incur indebtedness under, and grant the related security interests for the Term Loan discussed below. Such amendments and modifications include the granting of a second priority lien on VNG's interests in ENP GP and the ENP Units. In addition to the existing first priority liens on the assets of VNG and its subsidiaries, amounts outstanding under the reserve-based credit facility will also be secured by a second priority lien on VNG's interest in ENP GP and the ENP Units. In December 2010, we entered into the Fourth Amendment to Second Amended and Restated Credit Agreement, which contains certain amendments necessary to exclude ENP GP's pledge of the general partners interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Second Amended and Restated Credit Agreement. Additionally, the Fourth Amendment clarifies the amounts guaranteed by subsidiaries of VNG pursuant to guaranty agreements previously delivered by such subsidiaries. At March 31, 2011, we had $179.0 million outstanding under our reserve-based credit facility and the applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	*≤50%*	*>50% <75%*	*≥75% <90%*	*≥90%*
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%
Commitment Fee Rate	0.50%	0.50%	0.50%	0.50%
Letter of Credit Fee	2.25%	2.50%	2.75%	3.00%

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, engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets, or make distributions to our unitholders when our outstanding borrowings exceed 90% of our borrowing base. We received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged to no greater than 85% of the actual outstanding balance. At March 31, 2011, we were in compliance with all of our debt covenants. In May 2011, the borrowing base was redetermined. See Note 11. *Subsequent Events* for further discussion.

Our reserve-based credit facility required us to enter into a commodity price hedge position establishing certain minimum fixed prices for anticipated future production. See Note 5. *Price and Interest Rate Risk Management Activities* for further discussion.

Term Loan

Concurrent with the Encore Acquisition, VNG entered into a $175.0 million Term Loan with BNP Paribas to fund a portion of the consideration for the acquisition.

Borrowings under the Term Loan are comprised entirely of ABR Loans or Eurodollar Loans as VNG may request. Interest on ABR Borrowings under the Term Loan is payable quarterly on the last day of each March, June, September and December and accrues at a rate per annum equal to 6.50% plus the greater of (a) the prime rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus ½ of 1%, and (c) the Adjusted LIBO Rate in effect on such day plus 2%. Interest on Eurodollar Borrowings is payable on the last day of the interest period applicable to such borrowing, and in the case of a Eurodollar Borrowing with an interest period of more than three months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period. Amounts outstanding under the Term Loan may be prepaid prior to maturity, together with all accrued and unpaid interest relating to the amount prepaid, without prepayment penalty. The Term Loan contains various covenants, including restrictions on liens, restrictions on incurring other indebtedness without the lenders' consent and restrictions on entering into certain transactions. The Term Loan matures the earlier of the first anniversary of the effective date (December 31, 2011) or the date following both the completion of any acquisition by Vanguard of the remainder of ENP and VNG's execution and delivery of a new or amended and restated revolving credit facility replacing VNG's current reserve-based credit facility.

Amounts outstanding under the Term Loan are secured by a second priority lien on all assets of VNG and its subsidiaries securing VNG's current reserve-based credit facility (other than VNG's interest in ENP GP and the ENP Units) and a first priority lien on VNG's interest in ENP GP and the ENP Units.

Our Term Loan contains a number of customary covenants that among other things require us to maintain certain financial ratios. At March 31, 2011, we were in compliance with the terms of our Term Loan.

ENP's Credit Agreement

ENP entered into a five-year credit agreement dated March 7, 2007 (as amended, the "ENP Credit Agreement"). The Credit Agreement matures on March 7, 2012; therefore, all outstanding borrowings under the Credit Agreement are reflected as a current liability at March 31, 2011. ENP is currently evaluating its options including extending the term of the Credit Agreement, or refinancing under a new revolving credit facility.

The Credit Agreement provides for revolving credit loans to be made to ENP from time to time and letters of credit to be issued from time to time for the account of ENP or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the Credit Agreement is $475.0 million. Availability under the Credit Agreement is subject to a borrowing base of $375.0 million, which is redetermined semi-annually and upon requested special redeterminations. As of March 31, 2011, there were $224.0 million of outstanding borrowings and $151.0 million of borrowing capacity under the Credit Agreement. In April 2011, the borrowing base was redetermined. See Note 11. *Subsequent Events* for further discussion.

ENP incurs a quarterly commitment fee at a rate of 0.5 % per year on the unused portion of the ENP Credit Agreement. Obligations under the ENP Credit Agreement are secured by a first-priority security interest in substantially all of ENP's proved oil and natural gas reserves and in the equity interests of ENP and its restricted subsidiaries. In addition, obligations under the ENP Credit Agreement are guaranteed by us and ENP's restricted subsidiaries. Obligations under the ENP Credit Agreement are non-recourse to Vanguard.

Loans under the ENP Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Such loans bear interest at the applicable rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	***<50%***	***≥50% <75%***	***≥75% <90%***	***≥90%***
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%

The "Eurodollar rate" for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The "Base Rate" is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its "prime rate"; (2) the Federal Funds Effective Rate plus 0.5 %; or (3) except during a "LIBOR Unavailability Period," the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 %.

ENP's Credit Agreement contains a number of customary covenants that requires ENP to maintain certain financial ratios, limits ENP's 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 and engage in certain asset dispositions, including a sale of all or substantially all of the ENP's assets. As of March 31, 2011, ENP was in compliance with all covenants of the ENP Credit Agreement.

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, the Company receives 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. 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 enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under 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*," all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We 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 other commodity derivative contracts or gains (losses) on interest rate derivative contracts in the 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 other commodity derivative contracts or gains (losses) on interest rate derivative contracts in the consolidated statements of operations.

As of March 31, 2011, we have 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
VNG				
April 1, 2011 – December 31, 2011	2,566,807	$ 7.78	359,750	$ 89.19
January 1, 2012 – December 31, 2012	915,000	$ 5.50	384,300	$ 91.38
January 1, 2013 – December 31, 2013	—	$ —	305,400	$ 90.26
January 1, 2014 – December 31, 2014	—	$ —	209,875	$ 94.37
ENP				
April 1, 2011 – December 31, 2011	2,805,550	$ 6.06	394,625	$ 81.62
January 1, 2012 – December 31, 2012	3,367,932	$ 5.75	947,940	$ 83.29
January 1, 2013 – December 31, 2013	2,993,000	$ 5.10	1,295,750	$ 88.95
January 1, 2014 – December 31, 2014	—	$ —	1,168,000	$ 88.95
Consolidated				
April 1, 2011 – December 31, 2011	5,372,357	$ 6.88	754,375	$ 85.23
January 1, 2012 – December 31, 2012	4,282,932	$ 5.70	1,332,240	$ 85. 62
January 1, 2013 – December 31, 2013	2,993,000	$ 5.10	1,601,150	$ 89.20
January 1, 2014 – December 31, 2014	—	$ —	1,377,875	$ 89.78

Swaptions

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

	Oil	
Contract Period	Bbls	Weighted Average Fixed Price
VNG		
January 1, 2012 - December 31, 2012	91,500	$ 95.20
January 1, 2013 - December 31, 2013	32,100	$ 95.00
January 1, 2014 - December 31, 2014	127,750	$ 95.00
January 1, 2015 - December 31, 2015	292,000	$ 95.63

Collars

	Gas			Oil		
Production Period	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
VNG						
April 1, 2011 – December 31, 2011	1,366,500	$ 7.28	$ 8.35	—	$ —	$ —
January 1, 2012 – December 31, 2012	—	$ —	$ —	82,350	$ 86.67	$ 102.36
January 1, 2013 – December 31, 2013	—	$ —	$ —	45,625	$ 80.00	$ 100.25
ENP						
April 1, 2011 – December 31, 2011	—	$ —	$ —	517,000	$ 80.00	$ 96.48
January 1, 2012 – December 31, 2012	—	$ —	$ —	475,800	$ 74.23	$ 90.98
Consolidated						
April 1, 2011 – December 31, 2011	1,366,500	$ 7.28	$ 8.35	517,000	$ 80.00	$ 96.49
January 1, 2012 – December 31, 2012	—	$ —	$ —	558,150	$ 76.07	$ 92.66
January 1, 2013 – December 31, 2013	—	$ —	$ —	45,625	$ 80.00	$ 100.25

Puts

	Gas	
Contract Period	MMBtu	Weighted Average Fixed Price
ENP		
April 1, 2011 – December 31, 2011	934,450	$ 6.31
January 1, 2012 – December 31, 2012	328,668	$ 6.76

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, 2011, we have open interest rate derivative contracts as follows (in thousands):

Period:	Notional Amount	Fixed Libor Rates
VNG		
April 1, 2011 to December 10, 2012	$ 20,000	3.35%
April 1, 2011 to January 31, 2013	$ 20,000	2.38%
April 1, 2011 to January 31, 2013	$ 20,000	2.66%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
ENP		
April 1, 2011 to March 31, 2012	$ 50,000	2.42%

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018.

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, 2011	December 31, 2010
Assets:		
Commodity derivatives	$ 31,831	$ 33,435
Interest rate swaps	469	97
	$ 32,300	$ 33,532
Liabilities:		
Commodity derivatives	$ (122,311)	$ (48,008)
Interest rate swaps	(3,364)	(4,115)
	$ (125,675)	$ (52,123)

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 $32.3 million at March 31, 2011.

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 somewhat mitigated as of March 31, 2011.

Gain (Loss) on Derivatives

Gains and losses on derivatives that are not accounted for as cash flow hedges are reported on the consolidated statement of operations in "realized or unrealized gain (loss) on other 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, 2011	Three Months Ended March 31, 2010
Realized gains (losses):		
Other commodity derivatives	$ 1,379	$ 5,214
Interest rate swaps	(893)	(515)
	$ 486	$ 4,699
Unrealized gains (losses):		
Other commodity derivatives	$ (72,560)	$ 10,810
Interest rate swaps	1,102	(250)
	$ (71,458)	$ 10,560
Total gains (losses):		
Other commodity derivatives	$ (71,181)	$ 16,024
Interest rate swaps	209	(765)
	$ (70,972)	$ 15,259

5. Fair Value Measurements

We adopted ASC Topic 820 for financial assets and financial liabilities as of January 1, 2008 and for non-financial assets and liabilities as of January 1, 2009. ASC Topic 820 does not expand the use of fair value measurements, but rather, 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 carried at fair value subsequent to an impairment write-down. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on Securities and Exchange Commission ("SEC") rules. ASC Topic 820 applies to assets and liabilities carried at fair value on the consolidated balance sheet, as well as to supplemental fair value information about financial instruments not carried at fair value.

The estimated fair values of our financial instruments closely approximate the carrying amounts as discussed below:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, payables to affiliates, phantom unit compensation accrual, accrued ad valorem taxes and accrued expenses. The carrying amounts approximate fair value due to the short maturity of these instruments.

Debt. The carrying amount of our financing arrangements approximates fair value because our current borrowing rates do not materially differ from market rates for similar bank borrowings.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis. This includes natural gas, oil and interest rate derivatives contracts. 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. These assumptions include certain factors not consistently provided for previously by those companies utilizing fair value measurement; examples of such factors would include our own credit standing (when valuing liabilities) and the buyer's risk premium. In adopting ASC Topic 820, we determined that the impact of these additional assumptions on fair value measurements did not have a material effect on our financial position or results of operations.

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. Our commodity derivative instruments consist of swaps, options and swaptions. 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 and ceilings 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, 2011			
	Fair Value Measurements Using			Assets/Liabilities at Fair value
	Level 1	Level 2	Level 3	
Assets:				
Commodity price derivative contracts	$ —	$ 4,966	$ —	$ 4,966
Interest rate derivative contracts		469		469
Total derivative instruments	$ —	$ 5,435	$ —	$ 5,435
Liabilities:				
Commodity price derivative contracts	$ —	$ (95,446)	$ —	$ (95,446)
Interest rate derivative contracts	—	(3,364)	—	(3,364)
Total derivative instruments	$ —	$ (98,810)	$ —	$ (98,810)

	December 31, 2010			
	Fair Value Measurements Using			Assets/Liabilities at Fair value
	Level 1	Level 2	Level 3	
Assets:				
Commodity price derivative contracts	$ —	$ 17,359	$ —	$ 17,359
Interest rate derivative contracts		643		643
Total derivative instruments	$ —	$ 18,002	$ —	$ 18,002
Liabilities:				
Commodity price derivative contracts	$ —	$ (31,931)	$ —	$ (31,931)
Interest rate derivative contracts	—	(4,662)	—	(4,662)
Total derivative instruments	$ —	$ (36,593)	$ —	$ (36,593)

On January 1, 2009, we adopted the previously-deferred provisions of ASC Topic 820 for nonfinancial assets and liabilities, which are comprised primarily of asset retirement costs and obligations initially measured at fair value in accordance with ASC Topic 410 Subtopic 20 " *Asset Retirement Obligations*" ("ASC Topic 410-20"). 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, 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 (5.0%); and (4) the ten year average inflation factor (2.3%). The adoption of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, did not have a material impact on our financial position or results of operations.

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):

	2011	2010
Asset retirement obligations at January 1,	$ 30,202	$ 4,420
Liabilities added during the current period	91	—
Accretion expense	188	37
Total asset retirement obligation at March 31,	30,481	4,457
Less: current obligations	(888)	—
Long-term Asset retirement obligation at March 31,	$ 29,593	$ 4,457

7. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. We reimburse Vinland $60 per well per month (in addition to normal third party operating costs) for operating our current oil and natural gas properties in Appalachia under a Management Services Agreement ("MSA") which costs are reflected in our lease operating expenses. Under a Gathering and Compression Agreement ("GCA"), Vinland receives a $0.25 per Mcf transportation fee on existing wells drilled at 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 has been signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the GCA. In the event no agreement is reached between us and Vinland, all the terms of the agreements will revert back to the original agreements effective July 1, 2010. Under the GCA, the transportation fee that we pay to Vinland only encompasses transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets would apply. These transportation fees are outlined in the GCA and are reflected in our lease operating expenses. Costs incurred under the MSA were $0.4 million and $0.5 million for the three months ended March 31, 2011 and 2010, respectively. Costs incurred under the GCA were $0.5 million and $0.3 million for the three months ended March 31, 2011 and 2010, respectively. A payable of $1.2 million and $0.6 million, respectively, is reflected on our March 31, 2011 and December 31, 2010 consolidated balance sheets in connection with these agreements and direct expenses incurred by Vinland related to the drilling of new wells and operations of all of our existing wells in Appalachia.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P., OLLC and Denbury. The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG provides certain general and administrative services to the ENP Group in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group's total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the "Administrative Fee"). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement. VNG received administrative fees amounting to $1.6 million, COPAS recovery amounting to $0.8 million and received reimbursements of third-party expenses amounting to $1.9 million during the three months ended March 31, 2011. The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the Council of Petroleum Accountants Societies ("COPAS") Wage Index Adjustment for that year;
- if ENP acquires additional assets, VNG may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of the ENP GP upon the recommendation of its conflicts committee; and
- otherwise as agreed upon by VNG and the ENP GP, with the approval of the conflicts committee of the board of directors of the ENP GP.

See Note 11. *Subsequent Events* for further discussion of change in COPAS Wage Index Adjustment.

8. Common Units and Net Income (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, 2011, we have two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on the NYSE under the symbol VNR and (ii) Class B units, issued to management and an employee as discussed in Note 9. 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, 2011, the 175,000 options granted to officers under the long-term incentive plan have been excluded in the computation of diluted earnings per unit as they had no dilutive effect. For the three months ended March 31, 2010, these options were included in the computation of diluted earnings per unit as 36,631 additional common units would be issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period, respectively. The 85,000 phantom units granted to officers during 2010 and 2011 under our long-term incentive plan had no dilutive effect on earnings per unit for the three months ended March 31, 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, 2011 and 2010 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.

9. Unit-Based Compensation

In April 2007, the sole member at that time reserved 460,000 restricted Class B units in VNR for issuance to employees. Certain members of management were granted 365,000 restricted Class B units in VNR in April 2007, which vested in April 2009, two years from the date of grant. In addition, another 55,000 restricted VNR Class B units were issued in August 2007 to two other employees that were hired in April and May of 2007, which vested in April and May 2010, three years after the date of grant. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future.

In October 2007, two officers were granted options to purchase an aggregate of 175,000 units under our long-term incentive plan 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. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718 "*Compensation-Stock Compensation*" ("ASC Topic 718"), 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%, the Company, due to a lack of historical data regarding the Company's 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, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the "Amended Agreements") with two executives. The 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 agreements should not be extended. Also in June 2010, the Company and VNRH entered into a second amended and restated Executive Employment Agreement (the "Amended Agreement") with one executive. The 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 agreements should not be extended. All three 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 Amended Agreements entered into in February 2010 and by the Chief Executive Officer for the Amended Agreement entered into in June 2010. 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.

The Amended Agreements entered into in February 2010 also provide for each executive to receive 15,000 restricted units granted pursuant to the Vanguard Natural Resources, LLC Long-Term Incentive Plan (the "LTIP") and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 restricted units granted pursuant to the LTIP. The restricted units are subject to a vesting period of three years. One-third of the aggregate number of the restricted units will vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. In the event the executives are terminated without "Cause," or the executive resigns for "Good Reason" (each term of which is defined in the executive's respective Amended Agreement), or the executive is terminated due to his death or "Disability" (as such term is defined in the Amended Agreement), all unvested outstanding restricted units shall receive accelerated vesting. Where the executive is terminated for "Cause," all restricted units, whether vested or unvested, will be forfeited. Upon the occurrence of a "Change of Control," (as defined in the LTIP), all unvested outstanding restricted units shall vest.

In addition, the Amended Agreements entered into in February 2010 provide for each executive to receive an annual grant of 15,000 phantom units granted pursuant to the LTIP and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 phantom units granted pursuant to the LTIP. The phantom units are also 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 the Company 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 the Company on its units generally with respect to the number of phantom shares that executive received pursuant to this grant. In the event the executive is terminated for "Cause" (as such term is defined in the Amended Agreement), 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 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, 2011, an accrued liability of $0.4 million has been recorded and non-cash unit-based compensation expense of $0.2 million and $0.03 million has been recognized related to these phantom units for the three months ended March 31, 2011 and 2010, respectively, in the selling, general and administrative expense line item in the consolidated statement of operations.

In January and February 2011, VNR employees were granted a total of 104,587 common units which vest equally over a four year period, but have distribution equivalent rights that provide the employees with a payment equal to the distribution on unvested units.

These common units, Class B 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, 2011 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2010	66,719	$ 22.18
Granted	104,587	$ 29.24
Forfeited	(4,315)	$ (28.97)
Vested	(27,719)	$ (22.53)
Non-vested units at March 31, 2011	139,272	$ 27.20

At March 31, 2011, there was approximately $3.5 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.9 years. Our consolidated statements of operations reflects non-cash compensation of $0.3 million in the selling, general and administrative line item for each of the three months ended March 31, 2011 and 2010, respectively.

In September 2007, the board of directors of ENP GP adopted the Encore Energy Partners GP LLC Long-Term Incentive Plan (the “LTIP”), which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. All employees, consultants, and directors of ENP GP and its affiliates who perform services for or on behalf of ENP and its subsidiaries are eligible to be granted awards under the LTIP. The LTIP is administered by the board of directors of ENP GP or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the LTIP, ENP may acquire common units in the open market, use common units owned by ENP GP, or use common units acquired by ENP GP from ENP or from any other person.

The total number of common units reserved for issuance pursuant to the LTIP is 1,150,000. In January and February 2011, ENP issued 140,007 restricted units under the LTIP to Vanguard field employees performing services on ENP’s properties. These awards vest equally over a four year period, but have distribution equivalent rights that provide the employees with a bonus equal to the distribution on unvested units. The weighted average grant date fair value of these units was $22.21 per unit and the total fair value was approximately $3.1 million on the date of grant. As of March 31, 2011, there were 934,993 common units available for issuance under the LTIP.

As of March 31, 2011, there was approximately $2.9 million of unrecognized compensation cost related to non-vested ENP restricted units, which is expected to be recognized over a period of 3.8 years. The consolidated statements of operations reflects non-cash compensation of $0.2 million in the selling, general and administrative expense line item for the three months ended March 31, 2011 related to these ENP units.

10. Shelf Registration Statements

In November 2008, ENP’s shelf registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion. The shelf registration statement does not provide assurance that ENP will or could sell any such securities. ENP’s ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase ENP securities at acceptable prices. In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. As a result of these offerings, as of March 31, 2011, ENP has approximately $822.1 million remaining available under its shelf registration statement.

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the 2009 shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

In August 2009, we completed an offering of 3.9 million of our common units. The units were offered to the public at a price of $14.25 per unit. We received net proceeds of approximately $53.2 million from the offering, after deducting underwriting discounts of $2.4 million and offering costs of $0.5 million. In December 2009, we completed an offering of 2.6 million of our common units. The units were offered to the public at a price of $18.00 per unit. We received net proceeds of approximately $44.4 million from the offering, after deducting underwriting discounts of $2.0 million and offering costs of $0.1 million. We paid $4.3 million of the proceeds from this offering to redeem 250,000 common units from our founding unitholder.

In May 2010, we completed an offering of 3.3 million of our common units. The units were offered to the public at a price of $23.00 per unit. We received proceeds of approximately $71.5 million from the offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.1 million.

In July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the 2010 shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

In August 2010, we entered into an equity distribution agreement relating to our common units representing limited liability company interests having an aggregate offering price of up to $60.0 million. In accordance with the terms of the equity distribution agreement we may offer and sell up to the maximum dollar amount of our units from time to time through our sales agent. Sales of the units, if any, may be made by means of ordinary brokers' transactions through the facilities of the New York Stock Exchange, (the “NYSE”), at market prices. Our sales agent will receive from us a commission of 1.25% based on the gross sales price per unit for any units sold through it as agent under the equity distribution agreement. During September through December 2010, we received net proceeds of approximately $6.3 million from the sales of 240,111 common units, after commissions.

In October 2010, we completed an offering of 4.8 million of our common units. The units were offered to the public at a price of $25.40 per unit. We received net proceeds of approximately $115.8 million from the offering, after deducting underwriting discounts of $5.1 million and offering costs of $0.3 million. We paid $3.7 million of the proceeds of this offering to redeem 150,000 common units from our founding unitholder. The net proceeds of $112.1 million were used to pay down outstanding borrowings under our reserve-based credit facility.

As a result of these offerings, as of March 31, 2011, we have approximately $62.6 million and $678.8 million remaining available under our 2009 and 2010 shelf registration statements, respectively.

11. Subsequent Events

Effective April 1, 2011, the administrative fee to be paid to VNG pursuant to the administration services agreement decreased from $2.06 per BOE of ENP’s production to $2.05 per BOE as the COPAS Wage Index Adjustment decreased 0.7 percent. On April 14, 2011, the borrowing base under the ENP Credit Agreement was increased from $375.0 million to $400.0 million pursuant to the semi-annual redetermination. All other terms of the Credit Agreement remained the same.

On April 28, 2011, the board of directors declared a cash distribution attributable to the first quarter of 2011 of $0.57 per unit expected to be paid on May 13, 2011 to Vanguard unitholders of record as of the close of business on May 6, 2011. On May 5, 2011, four board members were granted 9,000 common units which vest one year from the date of grant.

On May 12, 2011, the borrowing base under our reserve-based credit facility was increased from $225.0 million to $235.0 million pursuant to the semi-annual redetermination. All other terms of the reserve-based credit facility remained the same.

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

The following discussion and analysis should be read in conjunction with the financial statements and related notes presented in Item 1 of this Quarterly Report on Form 10-Q and information disclosed in our 2010 Annual Report on Form 10-K.

Forward-Looking Statements

This report contains "forward-looking statements" intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995. Statements included in this Quarterly Report 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 Factor section of the 2010 Annual Report on Form 10-K and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the SEC, which are available on our website at www.vnrllc.com and through the SEC's Electronic Data Gathering and Retrieval System ("EDGAR") 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.

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 to increase our quarterly cash distributions through the acquisition of new oil and natural gas. We own a 100% controlling interest, through certain of our subsidiaries, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- south Texas;
- the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee; and
- Mississippi.

In addition, we own an approximate 46.6% aggregate controlling interest through our subsidiary, ENP, in properties and oil and natural gas reserves located in four operating areas:

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

At March 31, 2011, we owned working interests in 4,895 gross (2,270 net) productive wells, including those wells acquired in the Encore Acquisition, which are subject to a 53.4% non-controlling interest. Our average net production per day for the year ended December 31, 2010 and for the three months ended March 31, 2011 was 4,721 BOE per day and 13,273 BOE per day, respectively. Our average net production for the year ended December 31, 2010, did not include any production from properties acquired in connection with the Encore Acquisition. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. As of March 31, 2011, we had a 40% working interest in approximately 109,291 gross undeveloped acres surrounding or adjacent to our existing wells located in the Appalachian Basin. In South Texas and the Permian Basin, VNR owns working interests ranging from 30-100% in approximately 15,890 undeveloped acres surrounding our existing wells. Additionally, ENP owns working interests ranging from 8-77% in approximately 15,372 undeveloped acres surrounding their existing wells in the Permian Basin, Big Horn Basin, Williston Basin and Arkoma Basin. As of March 31, 2011, based on internal reserve estimates, approximately 20% or 13.6 MMBOE of our estimated proved reserves were attributable to our working interests in undeveloped acreage. The proved undeveloped reserves that we acquired in connection with the Encore Acquisition are subject to a 53.4% non-controlling interest in ENP.

Recent Developments

Encore Acquisition

On December 31, 2010, we completed an acquisition pursuant to a purchase agreement with Denbury Resources Inc. (“Denbury”), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the “Encore Selling Parties” and, together with Denbury, the “Selling Parties”) to acquire (the “Encore Acquisition” or “Encore”) all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the “ENP Units”), representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. (“Encore Operating”), OLLC and Denbury (the “Services Agreement”). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG provides certain general and administrative services to ENP, ENP GP and the OLLC (collectively, the “ENP Group”) in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group’s total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the “Administrative Fee”). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement.

On March 24, 2011, VNR delivered a formal proposal to the chairman of the Conflicts Committee (the “Conflicts Committee”) of ENP GP, the general partner of ENP, to acquire all of the outstanding common units of ENP, for consideration of 0.72 common unit of VNR for each outstanding common unit of ENP in a transaction to be structured as a merger of ENP with VNG. The Conflicts Committee of ENP GP has retained Bracewell & Giuliani as legal advisors and Jefferies & Company as financial advisors to assist in the evaluation of the proposal from VNR. The proposal of VNR is subject to customary terms and conditions, including applicable board and special committee approvals and the negotiation of definitive agreements. The Conflicts Committee of ENP GP is currently considering the proposal.

The fair value of the assets and liabilities we acquired on December 31, 2010 in the Encore Acquisition and cash flows associated with the transaction were included in the consolidated balance sheet as of December 31, 2010. We have consolidated ENP’s accounts since December 31, 2010, the acquisition date.

Acquisitions of Oil and Natural Gas Properties

Parker Creek Acquisition

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the “Parker Creek Acquisition.” The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 equity offering and with borrowings under the Company’s existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel. As of March 31, 2011, based on internal reserve estimates, these acquired properties had estimated proved reserves of 4.3 MMBOE, 97% of which is oil and 55% is proved developed.

Our Relationship with Vinland

On April 18, 2007 but effective as of January 5, 2007, we entered into various agreements with Vinland, under which we rely on Vinland to operate our existing producing wells in Appalachia and coordinate our development drilling program in Appalachia. We expect to benefit from the substantial development and operational expertise of Vinland management in the Appalachian Basin. Under a management services agreement, Vinland advises and consults with us regarding all aspects of our production and development operations in Appalachia and provides us with administrative support services as necessary for the operation of our business. Under a gathering and compression agreement that we entered into with Vinland Energy Gathering, LLC ("VEG"), VEG gathers, compresses, delivers, and provides the services necessary for us to market our natural gas production in the area of mutual interest, or "AMI." VEG delivers our natural gas production to certain designated interconnects with third-party transporters.

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 natural gas liquids 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 a distribution. We have mitigated the volatility on our cash flows with natural gas price derivative contracts through 2013 and oil 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 natural gas liquids prices fluctuate, we will recognize non-cash, unrealized gains and losses in our consolidated statement 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 natural gas liquids 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, 2011, we drilled and completed three gross (1.2 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, our borrowing base under our reserve-based credit facility and the ENP Credit Agreement may be redetermined such that they 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,			
		2011		**2010(a)(b)**	
Revenues:					
Oil sales	$	56,090	$	9,666	
Natural gas sales		4,935		7,518	
Natural gas liquids sales		11,014		2,886	
Oil, natural gas and natural gas liquids sales		**72,039**		**20,070**	
Loss on commodity cash flow hedges		(1,071)		(1,042)	
Realized gain on other commodity derivative contracts		1,379		5,214	
Unrealized gain (loss) on other commodity derivative contracts		(72,560)		10,810	
Total revenues	**$**	**(213)**	**$**	**35,052**	
Costs and expenses:					
Production:					
Lease operating expenses	$	12,900	$	4,073	
Production taxes and marketing		6,222		1,582	
Depreciation, depletion, amortization, and accretion		19,827		4,238	
Selling, general and administrative expenses		4,308		1,400	
Total costs and expenses	**$**	**43,257**	**$**	**11,293**	
Other income and (expense):					
Interest expense	$	(6,787)	$	(1,291)	
Realized loss on interest rate derivative contracts	$	(893)	$	(515)	
Unrealized loss on interest rate derivative contracts	$	(1,102)	$	(250)	
Other	$	(2)	$	—	

(a) The Parker Creek Acquisition closed on May 20, 2010 and, as such, no operations are included in the three month period ended March 31, 2010.
(b) The Encore Acquisition closed on December 31, 2010 and, as such, no operations are included in the three month period ended March 31, 2010.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Revenues

Oil, natural gas and natural gas liquids sales increased $52.0 million to $72.0 million during the three months ended March 31, 2011 as compared to the same period in 2010. The key revenue measurements were as follows:

	Three Months Ended March 31,		Percentage Increase (Decrease)
	2011	2010(a)(b)	
Net Natural Gas Production:			
Appalachian gas (MMcf)	626	689	(9)%
Permian gas (MMcf)	115	97	19%
South Texas gas (MMcf)	402	423	(5)%
ENP gas (MMcf)	1,383	—	—
Total natural gas production (MMcf)	2,526	1,209	109%
Average Appalachian daily gas production (Mcf/day)	6,961	7,567	(9)%
Average Permian daily gas production (Mcf/day)	1,282	1,079	19%
Average South Texas daily gas production (Mcf/day)	4,465	4,700	(5)%
Average ENP daily gas production (Mcf/day)	15,368	—	—
Average daily gas production (Mcf/day)	28,076	13,436	109%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$7.30(c)	$10.12(c)	(28)%
Net realized gas price, excluding hedges	$4.36	$6.22	(30)%
Net Oil Production:			
Appalachian oil (Bbls)	25,631	32,356	(21)%
Permian oil (Bbls)	111,395	96,421	16%
South Texas oil (Bbls)	5,309	3,634	47%
Mississippi oil (Bbls)	52,745	—	—
ENP oil (Bbls)	489,967	—	—
Total oil production (Bbls)	685,047	132,411	417%
Average Appalachian daily oil production (Bbls/day)	285	360	(21)%
Average Permian daily oil production (Bbls/day)	1,237	1,071	16%
Average South Texas daily oil production (Bbls/day)	59	40	47%
Average Mississippi daily oil production (Bbls/day)	586	—	—
Average ENP daily oil production (Bbls/day)	5,444	—	—
Average daily oil production (Bbls/day)	7,611	1,471	417%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$77.86(c)	$77.28(c)	1%
Net realized oil price, excluding hedges	$81.81	$73.00	12%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Bbls)	7,637	9,044	(15)%
South Texas natural gas liquids (Bbls)	39,557	48,033	(18)%
ENP natural gas liquids (Bbls)	41,167	—	—
Total natural gas liquids production (Bbls)	88,361	57,077	55%
Average Permian daily natural gas liquids production (Bbls/day)	85	100	(15)%
Average South Texas daily natural gas liquids production (Bbls/day)	440	534	(18)%
Average ENP daily natural gas liquids production (Bbls/day)	457	—	—
Average daily natural gas liquids production (Bbls/day)	982	634	55%
Average Net Realized Natural Gas Liquids Sales Price per Bbl	$55.85	$50.57	10%

(a) The Parker Creek Acquisition closed on May 20, 2010 and, as such, no operations are included in the three month period ended March 31, 2010.
(b) The Encore Acquisition closed on December 31, 2010 and, as such, no operations are included in the three month period ended March 31, 2010.
(c) Excludes amortization of premiums paid and amortization of value on derivative contracts acquired.

The increase in oil, natural gas and natural gas liquids sales during the three months ended March 31, 2011 compared to the same period in 2010 was due primarily to the increases in production from our acquisitions. We experienced a 12% increase in the average realized oil price (excluding hedges) and a 30% decrease in the average realized natural gas sales price received (excluding hedges). Oil revenues increased 480% from $9.7 million in the first quarter of 2010 to $56.0 million in the first quarter of 2011 as a result of a $8.81 per Bbl increase in our average realized oil price and a 552.6 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 $78.61 per Bbl in the first quarter of 2010 to $94.25 per Bbl in the first quarter of 2011. However, we did not reap the entire benefit of the 20 percent increase in the NYMEX oil price due to significant widening of the basis differential received on our oil. Natural gas revenues decreased 34% from $7.5 million in the first quarter of 2010 to $4.9 million in the first quarter of 2011 as a result of a $1.86 per Mcf decrease in our average realized natural gas price primarily due to a lower average NYMEX price, which decreased from $5.36 per Mcf in the first quarter of 2010 to $4.11 per Mcf in the first quarter of 2011. The impact of the decrease in our realized natural gas price was offset by a 109% increase in our natural gas production volumes from the wells acquired in the Encore Acquisition. Additionally, our total production increased by 205% on a BOE basis. The increase in production for the three months ended March 31, 2011 over the comparable period in 2010 was primarily attributable to the impact from the Encore Acquisition and the Parker Creek Acquisition completed in December and May 2010, respectively. On a BOE basis, crude oil, natural gas, and natural gas liquids accounted for 57%, 35% and 8%, respectively, of our production during the three months ended March 31, 2011 compared to crude oil, natural gas, and natural gas liquids of 34%, 52% and 15%, respectively, during the same period in 2010.

Hedging and Price Risk Management Activities

During the three months ended March 31, 2011, the Company recognized a $1.4 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $72.6 million loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. These realized and unrealized gains and 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 and 2010, the Company recognized $1.1 million and $1.0 million in losses on commodity cash flow hedges that previously met the criteria for cash flow hedge accounting, respectively. 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 loss for the three months ended March 31, 2011 and 2010 relates 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 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 statement of operations. However, these fair value changes that are reflected in the consolidated statement 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 in Appalachia also include a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. In addition, we pay a $0.25 per Mcf and $0.55 per Mcf gathering and compression charge for production from wells drilled pre and post January 1, 2007, respectively, to Vinland pursuant to a gathering and compression agreement with Vinland. In June 2010, we began discussions with Vinland regarding an amendment to the gathering and compression agreement 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 although the formal agreements have not been signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the gathering and compression agreement. Lease operating expenses increased by $8.8 million to $12.9 million for the three months ended March 31, 2011 as compared to the three months ended March 31, 2010, of which $8.0 million related primarily to the Encore Acquisition and $0.5 million related to increased lease operating expenses for wells acquired in the Parker Creek Acquisition.

Production 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 taxes and marketing increased by $4.6 million for the three months ended March 31, 2011 as compared to the same period in 2010. Severance taxes increased by $3.8 million as a result of increased oil, natural gas and natural gas liquids sales due to the Encore Acquisition. Ad valorem taxes increased by $0.6 million primarily due to the taxes on oil and natural gas properties acquired in the Encore Acquisition.

Depreciation, depletion, amortization and accretion increased to approximately $19.8 million for the three months ended March 31, 2011 from approximately $4.2 million for the three months ended March 31, 2010 due primarily to approximately $14.7 million and $1.5 million additional depletion recorded on oil and natural gas properties acquired in the Encore Acquisition and the Parker Creek Acquisition, respectively.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended March 31, 2011 increased $2.9 million as compared to the three months ended March 31, 2010 principally due to approximately $1.6 million in incremental costs related to ENP, a $0.4 million increase in non-cash compensation charges related to the grant of units to employees and the grant of phantom units to officers and a $0.9 million increase in Vanguard's expenses related to the hiring of additional personnel and expanding operations in connection with the Encore Acquisition.

Other Income and Expense

Interest expense increased to $6.8 million for the three months ended March 31, 2011 compared to $1.3 million for the three months ended March 31, 2010 primarily due to approximately $2.5 million of interest expense on the Term Loan borrowed in connection with the Encore Acquisition, $2.2 million of interest expense incurred for ENP's Credit Agreement and higher average outstanding debt under our reserve-based credit facility during the three months ended March 31, 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, 2011, our critical accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2010.

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 natural gas liquids 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 natural gas liquids 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 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 12, 2011, we have $55.0 million and $176.0 million available to be borrowed under Vanguard's reserve-based credit facility and under ENP's Credit Agreement, respectively.

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 natural gas liquids prices) from our proved oil, natural gas and natural gas liquids reserves. If commodity prices decline in the future and banks lower their internal projections of oil, natural gas and natural gas liquids prices, it is possible that we will be subject to further decreases in our borrowing base availability in the future. On May 12, 2011, the borrowing base under our reserve-based credit facility was increased from $225.0 million to $235.0 million pursuant to the semi-annual redetermination. All other terms of the reserve-based credit facility remained the same. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold.

Our consolidated balance sheets include the $175.0 million one year Term Loan used to finance the Encore Acquisition and all of the outstanding debt of Encore as current liabilities. The ENP Credit Agreement is set to mature in March 2012 which requires that all outstanding borrowings under the ENP Credit Agreement be reflected as current liabilities on the balance sheet starting in March 2011. We are currently evaluating our options which, based on discussions with lenders, include extending the term of the revolving credit facility or refinancing under a new revolving credit facility. We will continue to monitor these options with lenders (and consider other potential solutions) in the coming months. However, the size or term of any extension to the ENP Credit Agreement or replacement of the ENP Credit Agreement as well as the refinancing of the $175.0 million one year Term Loan may be impacted should Encore merge with Vanguard.

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

Cash Flow from Operations

Net cash provided by operating activities was $44.8 million during the three months ended March 31, 2011, compared to $12.1 million during the three months ended March 31, 2010. The increase in cash provided by operating activities during the three months ended March 31, 2011 as compared to the same period in 2010 was substantially generated from increased production volumes related to the Encore Acquisition and the Parker Creek Acquisition. Changes in working capital decreased total cash flows by $2.6 million in 2011 compared to decreasing total cash flows by $5.0 million in 2010. Contributing to the decrease in working capital during 2011 was a $2.4 million decrease in accrued expenses and other current liabilities that resulted primarily from the timing effects of payments for transaction costs related to the Encore Acquisition and compensation related amounts and an increase in accounts receivable, offset by an increase in accounts payable due to the timing of invoicing. 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, 2011 or 2010.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and natural gas liquids prices. Oil, natural gas and natural gas liquids 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, swaptions and NYMEX collars to reduce our exposure to the volatility in oil, natural gas and natural gas liquids 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 2013 for natural gas and 2014 for oil.

Cash Flow from Investing Activities

Cash used in investing activities was approximately $7.8 million for the three months ended March 31, 2011, compared to $2.7 million during the same period in 2010. The increase in cash used in investing activities was primarily attributable to $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 as compared to $1.6 million for the drilling and development of oil and natural gas properties and $1.1 million for prepayments for the drilling and development of oil and natural gas properties during the three months ended March 31, 2010.

Cash Flow from Financing Activities

Cash used in financing activities was approximately $36.8 million for the three months ended March 31, 2011, compared to $9.7 million for the three months ended March 31, 2010. During the three months ended March 31, 2011, total net repayments under our financing arrangements were $7.5 million. Additionally, cash of $16.8 million was used in distributions to unitholders and $12.3 million in ENP's distributions to non-controlling interest. Cash used in financing activities during the three months ended March 31, 2010, included $9.9 million used in distribution to unitholders and $1.2 million in the purchase of units for issuance as unit based compensation. Offsetting cash used in financing activities during the three months ended March 31, 2010 was $1.4 million in net borrowings under our reserve-based credit facility.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240.0 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. The other terms and conditions of the reserve-based credit facility remained substantially the same. In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. Also in November 2010, in connection with the Encore Acquisition, we entered into the Third Amendment to the Second Amended and Restated Credit Agreement to provide for certain amendments and modifications to allow us to incur indebtedness under, and grant the related security interests for the Term Loan discussed below. Such amendments and modifications include the granting of a second priority lien on VNG's interests in ENP GP and the ENP Units. In addition to the existing first priority liens on the assets of VNG and its subsidiaries, amounts outstanding under the reserve-based credit facility will also be secured by a second priority lien on VNG's interest in ENP GP and the ENP Units. In December 2010, we entered into the Fourth Amendment to Second Amended and Restated Credit Agreement, which contains certain amendments necessary to exclude ENP GP's pledge of the general partners interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Second Amended and Restated Credit Agreement. Additionally, the Fourth Amendment clarifies the amounts guaranteed by subsidiaries of VNG pursuant to guaranty agreements previously delivered by such subsidiaries. At March 31, 2011, we had $179.0 million outstanding under our reserve-based credit facility and the applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	*≤50%*	*>50% <75%*	*≥75% <90%*	*≥90%*
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%
Commitment Fee Rate	0.50%	0.50%	0.50%	0.50%
Letter of Credit Fee	2.25%	2.50%	2.75%	3.00%

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 natural gas liquids prices) from our proved oil, natural gas and natural gas liquids reserves. On May 12, 2011, the borrowing base under our reserve-based credit facility was increased from $225.0 million to $235.0 million pursuant to the semi-annual redetermination. All other terms of the reserve-based credit facility remained the same. If commodity prices decline in the future and banks lower their internal projections of oil, natural gas and natural gas liquids prices, it is possible that we will be subject to further decreases in our borrowing base availability in the future. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold. As a result, absent accretive acquisitions, it is our current intention to utilize our excess cash flow during the remainder of 2011 to reduce our borrowings under our reserve-based credit facility. As of May 12, 2011, we have $55.0 million available to be borrowed under our reserve-based credit facility.

Borrowings under the reserve-based credit facility are available for the 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 2.25% and 3.00% per annum; or
- a domestic bank rate plus an applicable margin between 1.25% and 2.00% per annum.

As of March 31, 2011, we had elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

The reserve-based credit facility contains various covenants that limit our ability to:

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions;
- 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 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 (which is equal to our Adjusted EBITDA), and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0;
- 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; and
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 3.5 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 and if the amount of borrowings outstanding under our reserve-based credit facility is less than 90% of the borrowing base.

As of March 31, 2011, we were in compliance with all covenants under our reserve-based credit facility after consideration of the waivers granted in conjunction with the recent redetermination of our borrowing base. 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. Among others, 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 $2.0 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 $1.0 million 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 $1.0 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 Securities Exchange Act of 1934 and the rules of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests other than by Majeed S. Nami or his affiliates, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Term Loan

Concurrent with the Encore Acquisition, VNG entered into a $175.0 million Term Loan with BNP Paribas to fund a portion of the consideration for the acquisition.

Borrowings under the Term Loan are comprised entirely of ABR Loans or Eurodollar Loans as VNG may request. Interest on ABR Borrowings under the Term Loan is payable quarterly on the last day of each March, June, September and December and accrues at a rate per annum equal to 6.50% plus the greater of (a) the prime rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus ½ of 1%, and (c) the Adjusted LIBO Rate in effect on such day plus 2%. Interest on Eurodollar Borrowings is payable on the last day of the interest period applicable to such borrowing, and in the case of a Eurodollar Borrowing with an interest period of more than three months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period and accrues at a rate per annum of 5.50% plus the Adjusted LIBO Rate for the interest period in effect for such borrowing. Amounts outstanding under the Term Loan may be prepaid prior to maturity, together with all accrued and unpaid interest relating to the amount prepaid, without prepayment penalty. The Term Loan contains various covenants, including restrictions on liens, restrictions on incurring other indebtedness without the lenders' consent and restrictions on entering into certain transactions. The Term Loan matures the earlier of the first anniversary of the effective date (December 31, 2011) or the date following both the completion of any acquisition by Vanguard of the remainder of ENP and VNG's execution and delivery of a new or amended and restated revolving credit facility replacing VNG's current reserve-based credit facility.

Amounts outstanding under the Term Loan are secured by a second priority lien on all assets of VNG and its subsidiaries securing VNG's current reserve-based credit facility (other than VNG's interest in ENP GP and the ENP Units) and a first priority lien on VNG's interest in ENP GP and the ENP Units.

On December 31, 2010, VNG entered into the First Amendment to Term Loan Agreement, which contains certain amendments necessary to exclude ENP GP's pledge of the general partner's interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Term Loan Agreement.

The Term Loan also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- 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 (which is equal to our Adjusted EBITDA), and giving pro forma effect to cash distributions by ENP and ENP GP with respect to ENP Interests (annualized) less the aggregate amount of cash used to purchase equity interests of VNR, to interest expense of not less than 2.5 to 1.0;

- 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.

As of March 31, 2011, we were in compliance with all covenants under the Term Loan.

ENP's Credit Agreement

The syndicate of lenders underwriting ENP's Credit Agreement includes 15 banking and other financial institutions. None of the lenders are underwriting more than 8% of the total commitments. We believe the number of lenders and the small percentage participation of each, provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

ENP entered into a credit agreement dated March 7, 2007 (as amended, the "ENP Credit Agreement"). The ENP Credit Agreement matures on March 7, 2012; therefore all outstanding borrowings under the ENP Credit Agreement are reflected as a current liability at March 31, 2011. We are currently evaluating our options including extending the term of the ENP Credit Agreement or refinancing under a new revolving credit facility. We will continue to monitor these options with lenders (and consider other potential solutions) in the coming months. However, the size or term of any extension to the revolving credit facility or replacement of the revolving credit facility may be significantly impacted should we consummate the proposed merger with ENP.

The ENP Credit Agreement provides for revolving credit loans to be made to ENP from time to time and letters of credit to be issued from time to time for the account of ENP or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the ENP Credit Agreement is $475.0 million. Availability under the Credit Agreement was subject to a borrowing base of $375.0 million and on March 31, 2011, there were $224.0 million of outstanding borrowings and $151.0 million of borrowing capacity under the Credit Agreement. The borrowing base is redetermined semi-annually and upon requested special redeterminations. On April 14, 2011, the borrowing base was increased to $400.0 million pursuant to the semi-annual redetermination. On May 10, 2011, there were $224.0 million of outstanding borrowings and $176.0 million of borrowing capacity under the Credit Agreement.

ENP incurs a quarterly commitment fee at a rate of 0.5% per year on the unused portion of the ENP Credit Agreement. Obligations under the ENP Credit Agreement are secured by a first-priority security interest in substantially all of ENP's proved oil and natural gas reserves and in the equity interests of ENP and its restricted subsidiaries. In addition, obligations under the ENP Credit Agreement are guaranteed by us and ENP's restricted subsidiaries. Obligations under the ENP Credit Agreement are non-recourse to Vanguard.

Loans under the ENP Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	***<50%***	***≥50% <75%***	***≥75% <90%***	***≥90%***
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%

The "Eurodollar rate" for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The "Base Rate" is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its "prime rate"; (2) the Federal Funds Effective Rate plus 0.5 %; or (3) except during a "LIBOR Unavailability Period," the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 %.

Any outstanding letters of credit reduce the availability under the ENP Credit Agreement. Borrowings under the ENP Credit Agreement may be repaid from time to time without penalty.

The ENP Credit Agreement contains covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming partnership units, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on our assets and the assets of ENP and its subsidiaries, subject to permitted exceptions;

- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 % of anticipated production from proved producing reserves;
- a requirement that ENP maintain a ratio of consolidated current assets to consolidated current liabilities, as defined in the Credit Agreement which excludes the current portion of long term debt, of not less than 1.0 to 1.0;
- a requirement that ENP maintain a ratio of consolidated EBITDAX, as defined in the ENP Credit Agreement, to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and
- a requirement that ENP maintain a ratio of consolidated funded debt to consolidated adjusted EBITDAX, as defined in the ENP Credit Agreement, of not more than 3.5 to 1.0.

ENP's Credit Agreement contains customary events of default, which would permit the lenders to accelerate the debt if not cured within applicable grace periods. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under ENP's Credit Agreement to be immediately due and payable. As of March 31, 2011, we were in compliance with all covenants under ENP's Credit Agreement.

Off-Balance Sheet Arrangements

At March 31, 2011, 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. As of March 31, 2011, there were no loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of March 31, 2011 is provided in the following table (in thousands):

	Payments Due by Year						
	2011	**2012**	**2013**	**2014**	**2015**	**After 2015**	**Total**
Management base salaries	$ 623	$ 830	$ 97	$ —	$ —	$ —	$ 1,550
Asset retirement obligations (1)	888	775	1,067	607	433	26,711	30,481
Derivative liabilities (2)	29,309	45,404	25,582	18,542	6,838	—	125,675
Financing arrangements (3)	175,000	403,000	—	—	—	—	578,000
Operating leases	921	932	251	—	—	—	2,104
Development commitments (4)	890	—	—	—	—	—	890
Total	$ 207,631	$ 450,941	$ 26,997	$ 19,149	$ 7,271	$ 26,711	$ 738,700

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and decommissioning of ENP's 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 3. 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 income (loss) attributable to Vanguard unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) attributable to Vanguard unitholders plus net income (loss) attributable to the non-controlling interest. The result is net income (loss) which includes the non-controlling interest. 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 gains and losses on other commodity and interest rate derivative contracts;
- Deferred taxes;
- Unit-based compensation expense;
- 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
- Administrative services fees charged to Encore, 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, 2011 as compared to the three months ended March 31, 2010, Adjusted EBITDA increased 103%, from $18.5 million to $37.6 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended March 31, 2011	2010
Net income (loss) attributable to Vanguard unitholders	$ (30,412)	$ 21,703
Net loss attributable to non-controlling interest	(19,638)	—
Net income (loss)	(50,050)	21,703
Plus:		
Interest expense, including realized losses on interest rate derivative contracts	7,680	1,806
Depreciation, depletion, amortization and accretion	19,827	4,238
Amortization of premiums paid on derivative contracts	4,367	505
Amortization of value on derivative contracts acquired	52	610
Unrealized (gains) losses on other commodity and interest rate derivative contracts	71,458	(10,560)
Deferred taxes	112	(80)
Unit-based compensation expense	479	254
Fair value of phantom units granted to officers	212	27
Adjusted EBITDA before non-controlling interest	54,137	18,503
Non-controlling interest attributable to adjustments above	(17,260)	—
Administrative services fees eliminated in consolidation	740	—
Adjusted EBITDA attributable to Vanguard unitholders	$ 37,617	$ 18,503

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 natural gas liquids 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 natural gas liquids production. Realized pricing is primarily driven by the Columbia Gas Appalachian Index (“TECO Index”), Henry Hub, Houston Ship Channel, West Texas (“Waha Index”), El Paso Natural Gas Company (Permian Basin) and Colorado Interstate Gas Company (Rocky Mountains) prices for natural gas production and the West Texas Intermediate Light Sweet price for oil production. Pricing for oil, natural gas and natural gas liquids 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. 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. 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 for a three 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, 2011, the fair value of commodity derivative contracts was a liability of approximately $90.5 million, of which $16.0 million settles during the next twelve months.

The following table summarizes commodity derivative contracts in place at March 31, 2011:

	April 1, - December 31, 2011	Year 2012	Year 2013	Year 2014
Gas Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (MMBtu)	2,566,807	915,000	—	—
Fixed Price ($/MMBtu)	$ 7.78	$ 5.50	$ —	$ —
ENP				
Notional Volume (MMBtu)	2,805,550	3,367,932	2,993,000	—
Fixed Price ($/MMBtu)	$ 6.06	$ 5.75	$ 5.10	$ —
Consolidated				
Notional Volume (MMBtu)	5,372,357	4,282,932	2,993,000	—
Fixed Price ($/MMBtu)	$ 6.88	$ 5.70	$ 5.10	$ —
Collars:				
VNG				
Notional Volume (MMBtu)	1,366,500	—	—	—
Floor Price ($/MMBtu)	$ 7.28	$ —	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.35	$ —	$ —	$ —
Puts:				
ENP				
Notional Volume (MMBtu)	934,450	328,668	—	—
Fixed Price ($/MMBtu)	$ 6.31	$ 6.76	$ —	$ —
Total Gas Positions:				
VNG				
Notional Volume (MMBtu)	3,933,307	915,000	—	—
ENP				
Notional Volume (MMBtu)	3,740,000	3,696,600	2,993,000	—
Consolidated				
Notional Volume (MMBtu)	7,673,307	4,611,600	2,993,000	—

	April 1, - December 31, 2011	Year 2012	Year 2013	Year 2014
Oil Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (Bbls)	359,750	384,300	305,400	209,875
Fixed Price ($/Bbl)	$ 89.19	$ 91.38	$ 90.26	$ 94.37
ENP				
Notional Volume (Bbls)	394,625	947,940	1,295,750	1,168,000
Fixed Price ($/Bbl)	$ 81.62	$ 83.29	$ 88.95	$ 88.95
Consolidated				
Notional Volume (Bbls)	754,375	1,332,240	1,601,150	1,377,875
Fixed Price ($/Bbl)	$ 85.23	$ 85.62	$ 89.20	$ 89.78
Collars:				
VNG				
Notional Volume (Bbls)	—	82,350	45,625	—
Floor Price ($/Bbl)	$ —	$ 86.67	$ 80.00	$ —
Ceiling Price ($/Bbl)	$ —	$ 102.36	$ 100.25	$ —
ENP				
Notional Volume (Bbls)	517,000	475,800	—	—
Floor Price ($/Bbl)	$ 80.00	$ 74.23	$ —	$ —
Ceiling Price ($/Bbl)	$ 96.49	$ 90.98	$ —	$ —
Consolidated				
Notional Volume (Bbls)	517,000	558,150	45,625	—
Floor Price ($/Bbl)	$ 80.00	$ 76.07	$ 80.00	$ —
Ceiling Price ($/Bbl)	$ 96.49	$ 92.66	$ 100.25	$ —
Total Oil Positions:				
VNG				
Notional Volume (Bbls)	359,750	466,650	351,025	209,875
ENP				
Notional Volume (Bbls)	911,625	1,423,740	1,295,750	1,168,000
Consolidated				
Notional Volume (Bbls)	1,271,375	1,890,390	1,646,775	1,377,875

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

	Year 2012	Year 2013	Year 2014	Year 2015
Swaptions:				
Notional Volume (Bbls)	91,500	32,100	127,750	292,000
Weighted Average Fixed Price ($/Bbl)	$ 95.20	$ 95.00	$ 95.00	$ 95.63

Interest Rate Risks

At March 31, 2011, we had debt outstanding of $578.0 million. The amount outstanding under our reserve-based credit facility at March 31, 2011 of $179.0 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 $0.02 million 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 Term Loan at March 31, 2011 of $175.0 million. At March 31, 2011, we had outstanding borrowings under ENP's Credit Agreement of $224.0 million, $50.0 million of which has a fixed interest rate pursuant to an interest rate swap through March 2012 and the remainder is subject to floating market rates of interest that are linked to the Eurodollar rate. At this level of floating rate debt, if the Eurodollar rate increased 10%, we would incur an additional $0.04 million of interest expense per year.

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. During 2008, the company chose to de-designate its interest rate swaps as cash flow hedges as the terms of new contracts entered into in August 2008 no longer matched the terms of the original contracts, thus causing the interest rate hedges to be ineffective. The net unrealized gain related to the de-designated cash flow hedges is reported in accumulated other comprehensive income and is being reclassified to earnings in the month in which the transactions settle.

Effective January 1, 2011, ENP elected to de-designate its outstanding interest rate swaps as cash flow hedges and therefore, has recognized changes in the fair market value of its interest rate swaps in the Consolidated Statements of Operations. The net unrealized gain related to the de-designated cash flow hedges is reported in accumulated other comprehensive income and is being reclassified to earnings in the month in which the transactions settle.

The following summarizes information concerning our positions in open interest rate derivative contracts at March 31, 2011 (in thousands):

	Notional Amount	Fixed Libor Rates
Period:		
VNG		
April 1, 2011 to December 10, 2012	$ 20,000	3.35%
April 1, 2011 to January 31, 2013	$ 20,000	2.38%
April 1, 2011 to January 31, 2013	$ 20,000	2.66%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
ENP		
April 1, 2011 to March 31, 2012	$ 50,000	2.42%

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018.

Counterparty Risk

At March 31, 2011, 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	Current Liabilities	Long-Term Assets	Long-Term Liabilities	Total Amount Due From/(Owed To) Counterparty at March 31, 2011
Citibank, N.A. (A+)	$ 3,304	$ —	$ —	$ (1,095)	$ 2,209
Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA)	—	(6,167)	—	(14,077)	(20,244)
BNP Paribas (AA)	1,029	(8,773)	323	(22,562)	(29,983)
The Bank of Nova Scotia (AA-)	217	(3)	—	(11,145)	(10,931)
BBVA Compass (A)	—	(301)	—	(1,280)	(1,581)
Credit Agricole (AA-)	—	(5,762)	146	(15,740)	(21,356)
Royal Bank of Canada (AA-)	416	—	—	(10,858)	(10,442)
Bank of America (A+)	—	(1,047)	—	—	(1,047)
Total	$ 4,966	$ (22,053)	$ 469	$ (76,757)	$ (93,375)

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 of the end of the period covered by this Quarterly Report on Form 10-Q, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) was evaluated by our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, in accordance with rules of the Securities Exchange Act of 1934, as amended. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of March 31, 2011 to provide reasonable assurance that information required to be disclosed by us in our reports that we file or submit under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to management, including the principal executive and principal financial officer, as appropriate to allow timely decisions regarding required disclosure and recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Control over Financial Reporting

On December 31, 2010, we completed the acquisition of all of the member interest in ENP GP and 20,924,055 common units representing limited partnership interests in ENP, representing a 46.6% aggregate equity interest in ENP at March 31, 2011. Pursuant to this acquisition, the functions of the accounting department were transitioned to Houston and integrated with VNG's, and ENP's books and records were converted to a new accounting software. Additionally, the books and records of Vanguard and its subsidiaries were converted to the same accounting software and Vanguard Permian's production accounting functions that had been previously outsourced to a third party were brought in-house. As a result, our management is implementing new processes and modifying existing processes.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or government proceedings against us, or contemplated to be brought against us, under the various environmental 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 Form 10-Q 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 units, please refer to Part I- Item 1A- Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010 as supplemented by the risk factors set forth below. There has been no material change in the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2010 other than those set forth below.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating and capital costs and reduced demand for the oil and natural gas we produce.

In December 2009, the U.S. Environmental Protection Agency ("EPA") determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. In addition, on November 30, 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, beginning in 2012 for emissions occurring in 2011. Also, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of legislation.

The Fiscal Year 2012 Budget proposed by the President recommends elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies, and legislation has been introduced in Congress which would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect the value of an investment in our common units.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Removed and Reserved

Item 5. Other Information

None.

Item 6. Exhibits

EXHIBIT INDEX

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

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a — 14 of the Securities and 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 of the Securities and 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

SIGNATURE

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

VANGUARD NATURAL RESOURCES, LLC
(Registrant)

Date: May 13, 2011

/s/ Richard A. Robert

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

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13A- 14 OF THE SECURITIES AND EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Scott W. Smith, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rule 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 13, 2011

/s/ Scott W. Smith
Scott W. Smith
President and Chief
Executive Officer
(Principal Executive
Officer)
Vanguard Natural
Resources, LLC

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13A- 14 OF THE SECURITIES AND EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Richard A. Robert, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rule 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 13, 2011

/s/ Richard A. Robert
Richard A. Robert
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)
Vanguard Natural Resources,
LLC

EXHIBIT 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**

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott W. Smith, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Scott W. Smith
Scott W. Smith
President and Chief
Executive Officer
(Principal Executive
Officer)

May 13, 2011

EXHIBIT 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**

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard A. Robert, Executive Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company

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

May 13, 2011