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 June 30, 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 ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

Common units outstanding on August 4, 2011: 29,845,434.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
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GLOSSARY OF TERMS

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

/day	= per day	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
Bcf	= billion cubic feet	MMBbls	= million barrels
Bcfe	= billion cubic feet equivalents	MMBOE	= million barrels of oil equivalent
BOE	= barrel of oil equivalent	MMBtu	= million British thermal units
Btu	= British thermal unit	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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues:				
Oil, natural gas and natural gas liquids sales	$ 80,371	$ 19,446	$ 152,410	$ 39,516
Loss on commodity cash flow hedges	(601)	(517)	(1,672)	(1,559)
Realized gain on other commodity derivative contracts	1,193	6,547	2,572	11,761
Unrealized gain (loss) on other commodity derivative contracts	31,546	(90)	(41,014)	10,720
Total revenues	112,509	25,386	112,296	60,438
Costs and expenses:				
Production:				
Lease operating expenses	15,667	4,634	28,567	8,707
Production and other taxes	7,404	1,880	13,626	3,462
Depreciation, depletion, amortization, and accretion	21,551	5,713	41,378	9,951
Selling, general and administrative expenses	6,799	1,134	11,107	2,534
Total costs and expenses	51,421	13,361	94,678	24,654
Income from operations	61,088	12,025	17,618	35,784
Other income (expense):				
Interest expense	(6,841)	(1,523)	(13,628)	(2,814)
Realized loss on interest rate derivative contracts	(612)	(483)	(1,505)	(998)
Unrealized gain (loss) on interest rate derivative contracts	(803)	(434)	299	(684)
Loss on acquisition of natural gas and oil properties	(870)	(5,680)	(870)	(5,680)
Other	8	—	6	—
Total other expense	(9,118)	(8,120)	(15,698)	(10,176)
Net income	51,970	3,905	1,920	25,608
Less:				
Net income attributable to non-controlling interest	20,171	—	533	—
Net income attributable to Vanguard unitholders	$ 31,799	$ 3,905	$ 1,387	$ 25,608
Net income per Common and Class B units – basic & diluted	$ 1.05	$ 0.19	$ 0.05	$ 1.30
Weighted average units outstanding:				
Common units – basic	29,810	19,988	29,768	19,206
Common units – diluted	29,953	20,004	29,834	19,222
Class B units – basic & diluted	420	420	420	420

See accompanying notes to consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Net income	$ 51,970	$ 3,905	$ 1,920	$ 25,608
Net gains from derivative contracts:				
Reclassification adjustments for settlements	601	448	1,633	1,444
Other comprehensive income	601	448	1,633	1,444
Comprehensive income	$ 52,571	$ 4,353	$ 3,553	$ 27,052

See accompanying notes to consolidated financial statements

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

	June 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 5,460	$ 1,828
Trade accounts receivable, net	37,664	32,961
Derivative assets	6,146	16,523
Other current assets	1,681	1,474
Total current assets	50,951	52,786
Oil and natural gas properties, at cost	1,327,202	1,312,107
Accumulated depletion	(289,444)	(248,704)
Oil and natural gas properties evaluated, net – full cost method	1,037,758	1,063,403
Other assets		
Goodwill	420,955	420,955
Other intangible assets, net	8,927	9,017
Derivative assets	—	1,479
Deferred financing costs	3,772	5,649
Other assets	12,952	1,903
Total assets	$ 1,535,315	$ 1,555,192
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 2,524	$ 3,156
Affiliate	1,402	668
Accrued liabilities:		
Lease operating	5,718	5,156
Developmental capital	1,395	996
Interest	509	310
Production and other taxes	13,480	11,793
Derivative liabilities	11,935	6,209
Deferred swap premium liability	1,127	1,739
Oil and natural gas revenue payable	973	2,241
Other	4,228	8,202
Current portion, long-term debt	405,000	175,000
Total current liabilities	448,291	215,470
Long-term debt	185,000	410,500
Derivative liabilities	55,684	30,384
Asset retirement obligations, net of current portion	29,992	29,434
Other long-term liabilities	847	11
Total liabilities	719,814	685,799
Commitments and contingencies		
Members' equity		
Members' capital, 29,845,434 common units issued and outstanding at June 30, 2011 and 29,666,039 at December 31, 2010	287,329	318,597
Class B units, 420,000 issued and outstanding at June 30, 2011 and December 31, 2010	4,691	5,166
Accumulated other comprehensive loss	(1,399)	(3,032)
Total VNR members' equity	290,621	320,731
Non-controlling interest in subsidiary	524,880	548,662
Total members' equity	815,501	869,393
Total liabilities and members' equity	$ 1,535,315	$ 1,555,192

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 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 and $0.57 per unit to unitholders of record May 6, 2011)	—	(33,646)	—	(475)	—	—	(34,121)
Reduction of equity proceeds for offering costs	—	(105)	—	—	—	—	(105)
Unit-based compensation	179	1,096	—	—	—	—	1,096
Net income	—	1,387	—	—	—	533	1,920
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	1,633	—	1,633
ENP cash distributions to non-controlling interest	—	—	—	—	—	(24,315)	(24,315)
Balance at June 30, 2011	29,845	$ 287,329	420	$ 4,691	$ (1,399)	$ 524,880	$ 815,501

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating activities		
Net income	$ 1,920	$ 25,608
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	41,378	9,951
Amortization of deferred financing costs	2,096	604
Deferred taxes	14	—
Unit-based compensation	1,146	466
Non-cash compensation associated with phantom units granted to officers	233	48
Amortization of premiums paid on derivative contracts	4,838	998
Amortization of value on derivative contracts acquired	118	1,168
Unrealized (gains) losses on other commodity and interest rate derivative contracts	40,715	(10,036)
Loss on acquisition of natural gas and oil properties	870	5,680
Changes in operating assets and liabilities:		
Trade accounts receivable	(4,703)	(561)
Other receivables	—	90
Payables to affiliates	734	(452)
Other current assets	(126)	77
Price risk management activities, net	(947)	(115)
Accounts payable and oil and natural gas revenue payable	(1,900)	1,503
Accrued expenses and other current liabilities	(1,533)	(3,525)
Other assets	6	(47)
Net cash provided by operating activities	84,859	31,457
Investing activities		
Additions to property and equipment	(499)	(121)
Additions to oil and natural gas properties	(8,729)	(7,647)
Acquisitions of oil and natural gas properties	(12,042)	(112,349)
Deposits and prepayments of oil and natural gas properties	(10,689)	(948)
Proceeds on sale of oil and natural gas properties	4,975	—
Net cash used in investing activities	(26,984)	(121,065)
Financing activities		
Proceeds from borrowings	197,000	121,900
Repayment of debt	(192,500)	(80,000)
Proceeds from equity offering, net	(87)	71,374
Distributions to members	(34,121)	(19,778)
Financing costs	(220)	(698)
Purchase of units for issuance as unit-based compensation	—	(1,421)
ENP distributions to non-controlling interest	(24,315)	—
Net cash (used in) provided by financing activities	(54,243)	91,377
Net increase in cash and cash equivalents	3,632	1,769
Cash and cash equivalents, beginning of period	1,828	487
Cash and cash equivalents, end of period	$ 5,460	$ 2,256
Supplemental cash flow information:		
Cash paid for interest	$ 11,267	$ 2,148
Non-cash investing and financing activities:		
Asset retirement obligations	$ 406	$ 514
Deferred swap premium	$ 1,096	$ —

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”), 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) “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 natural 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 and 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 “Encore Selling Parties” and, together with Denbury, the “Selling Parties”) to acquire (the “Encore Acquisition” or “Encore”) all of the member interests 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 46.6% aggregate equity interest in ENP at June 30, 2011. As consideration for the purchase, we paid $300.0 million in cash and issued 3,137,255 VNR common units, valued at $93.0 million.

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 BOE 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. Effective April 1, 2011, the Administrative Fee 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. 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 July 11, 2011, Vanguard and ENP announced the execution of a definitive agreement that would result in a merger whereby ENP would become a wholly-owned subsidiary of VNG through a unit for unit exchange. See Note 12, *Subsequent Events,* for further discussion.

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 June 30, 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 June 30, 2011 and December 31, 2010 and for the three and six months ended June 30, 2011 and 2010 include our accounts and those of our subsidiaries. We present our financial statements in accordance with GAAP. All intercompany transactions and balances have been eliminated upon consolidation.

(b) Recently Adopted Accounting Pronouncements:

In December 2010, the Financial Accounting Standards Board ("FASB") issued authoritative guidance which includes amendments that affect any public entity as defined by Topic 805, Business Combinations, that enters into business combinations that are material on an individual or aggregate basis. The amendments in this guidance specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments are effective for us on January 1, 2011. As this guidance provides only disclosure requirements, the adoption of this standard did not impact our results of operations, cash flows or financial position.

In June 2011, the FASB issued authoritative guidance intended to improve the comparability, consistency, and transparency of financial reporting. The guidance is also intended to increase the prominence of items reported in other comprehensive income and to facilitate convergence of GAAP and International Financial Reporting Standards ("IFRS") by eliminating the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity. Under this guidance, entities are given two options for presenting other comprehensive income. The statement of other comprehensive income can be included with the statement of net income, which together will comprise the statement of total comprehensive income. Alternatively, the statement of other comprehensive income can be presented separate from the statement of net income. However, the guidance requires that the statement of other comprehensive income should immediately follow the statement of net income. The guidance also requires entities to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the components of net income and the components of other comprehensive income are presented. The guidance is effective for each reporting entity for interim and annual periods beginning after December 15, 2011. We early adopted this guidance beginning with the interim period ended June 30, 2011. As this guidance provides only presentation requirements, the adoption of this standard is not expected to have any impact on our results of operations, cash flows or financial position.

(c) New Pronouncements Issued But Not Yet Adopted:

In May 2011, the FASB issued authoritative guidance to achieve common fair value measurement and disclosure requirements in GAAP and IFRS. The guidance changes the wording used to describe the requirements in GAAP for measuring fair value and disclosures about fair value. The guidance includes clarification of the application of existing fair value measurements and disclosure requirements related to a) the application of highest and best use and valuation premise concepts; b) measuring the fair value of an instrument classified in a reporting entity's stockholders' equity and c) disclosure of quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy. Additionally, the guidance changes particular principles or requirements for measuring fair value and disclosing information about fair value measurements related to a) measuring the fair value of financial instruments that are managed within a portfolio, b) application of premiums and discounts in a fair value measurement and c) additional requirements to expand the disclosures about fair value measurements. The guidance is effective for each reporting entity for interim and annual periods beginning after December 15, 2011. The adoption of this standard is not expected to have any impact on our results of operations, cash flows or financial position.

(d) Use of Estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and 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.

(e) Non-controlling Interest:

As of June 30, 2011, Vanguard owned approximately 46.0% of ENP's outstanding common units. Vanguard also owns 100% of ENP GP, which is ENP's general partner, for an aggregate interest of 46.6% at June 30, 2011. 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 June 30, 2011, the $524.9 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 and six months ended June 30, 2011, "net income attributable to non-controlling interest" of $20.2 million and $0.5 million, respectively, 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 by 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 interests 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. The 3,137,255 VNR common units issued were 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.

On April 28, 2011, we entered into a Purchase and Sale Agreement with a private seller, for the acquisition of certain oil and natural gas properties located in Texas and New Mexico. We refer to this acquisition as the “Newfield Acquisition.” The purchase price for said assets was $9.1 million with an effective date of April 1, 2011. We completed this acquisition on May 12, 2011 for an adjusted purchase price of $9.2 million, subject to customary post-closing adjustments to be determined. This acquisition was funded with borrowings under the Company’s existing reserve-based credit facility.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Newfield Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in goodwill of $0.9 million, which was immediately impaired and recorded as a loss. The loss resulted from the changes in oil prices used to value the reserves and has been recognized in current period earnings and classified in other income and expense in the consolidated statement of operations.

The following unaudited pro forma results for each of the three and six months ended June 30, 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. Additionally, the following unaudited pro forma results for each of the three and six months ended June 30, 2011 and June 30, 2010 show the effect on our consolidated results of operations as if the Newfield Acquisition 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) the 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:

	Pro forma (in thousands, except per unit data)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Total revenues	$ 112,655	$ 89,378	$ 112,814	$ 183,171
Net income	$ 52,055	$ 26,735	$ 2,260	$ 63,378
Net income attributable to non-controlling interest	$ 20,171	$ 11,429	$ 533	$ 17,861
Net income attributable to VNR	$ 31,884	$ 15,306	$ 1,727	$ 45,516
Net income per unit:				
Common & Class B units – basic & diluted	$ 1.05	$ 0.61	$ 0.06	$ 1.80

The amount of revenues and excess of revenues over direct operating expenses included in our 2011 consolidated statements of operations for the Parker Creek and Newfield Acquisitions are shown in the table that follows (in thousands). Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Parker Creek				
Revenues	$ 4,994	$ 2,038	$ 9,851	$ 2,038
Excess of revenues over direct operating expenses	$ 4,675	$ 1,709	$ 8,718	$ 1,709
Newfield				
Revenues	$ 309	$ —	$ 309	$ —
Excess of revenues over direct operating expenses	$ 261	$ —	$ 261	$ —

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 June 30, 2011	Six Months Ended June 30, 2011
ENP		
Revenues	$ 76,498	$ 72,227
Net income	$ 37,772	$ 997

See Note 12. *Subsequent Events* for further discussion of acquisition of oil and natural gas properties in the Permian Basin of West Texas.

3. Debt

Our financing arrangements consisted of the following:

Description	Interest Rate	Maturity Date	Amount Outstanding June 30, 2011	Amount Outstanding December 31, 2010
			(in thousands)	
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 185,000	$ 176,500
Term Loan	Variable (2)	December 31, 2011	175,000	175,000
ENP's credit agreement	Variable (3)	March 7, 2012	230,000	234,000
Total debt			590,000	585,500
Less: current obligations			(405,000)	(175,000)
Total long term debt			$ 185,000	$ 410,500

(1) Variable interest rate was 2.95% and 3.00% at June 30, 2011 and December 31, 2010, respectively.
(2) Variable interest rate was 5.70% and 5.77% at June 30, 2011 and December 31, 2010.
(3) Weighted average interest rate was 2.72% and 2.80% at June 30, 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 included 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. 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. At June 30, 2011, we had $185.0 million outstanding under our reserve-based credit facility and the applicable margins and other fees will 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%

See Note 12. *Subsequent Events* for further discussion of interim redetermination of our reserve-based credit facility.

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. The credit agreement limits the amount of outstanding debt to be hedged to no greater than 85% of the actual outstanding balance. At June 30, 2011, we were in compliance with all of our debt covenants.

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 4. *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 LIBOR 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 six months' duration, each day prior to the last day of such interest period that occurs at intervals of six months' duration after the first day of such interest period and accrues at a rate per annum of 5.50% plus the Adjusted LIBOR Rate for the interest period in effect for such borrowings. 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 June 30, 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 June 30, 2011. In July 2011, Vanguard began the syndication of a new credit facility that would retire all of the outstanding debt of ENP upon the consummation of a merger with Vanguard. In the event that the merger is not consummated, we will continue to evaluate our options which, based on discussions with lenders, include extending the term of the ENP revolving credit facility 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 $400.0 million, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2011, there were $230.0 million of outstanding borrowings and $170.0 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. 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 June 30, 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 may enter into three-way collar contracts which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price of NYMEX West Texas Intermediate ("WTI") crude oil drops below the price of the short put. This allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. We temporarily enter into put spreads which combine a long put with a short put, with the intention of adding a short call to convert them into three-way collars. 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 June 30, 2011, we had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		Oil	
Contract Period	**MMBtu**	**Weighted Average Fixed Price**	**Bbls**	**Weighted Average WTI Price**
VNG				
July 1, 2011 – December 31, 2011	1,642,052	$ 7.81	254,900	$ 90.05
January 1, 2012 – December 31, 2012	1,281,000	$ 5.45	420,900	$ 92.42
January 1, 2013 – December 31, 2013	2,190,000	$ 5.62	305,400	$ 90.26
January 1, 2014 – December 31, 2014	—	$ —	209,875	$ 94.37
ENP				
July 1, 2011 – December 31, 2011	1,877,168	$ 6.06	279,340	$ 82.90
January 1, 2012 – December 31, 2012	3,733,932	$ 5.70	984,540	$ 84.10
January 1, 2013 – December 31, 2013	3,358,000	$ 5.12	1,295,750	$ 88.95
January 1, 2014 – December 31, 2014	—	$ —	1,168,000	$ 88.95
Consolidated				
July 1, 2011 – December 31, 2011	3,519,220	$ 6.88	534,240	$ 86.31
January 1, 2012 – December 31, 2012	5,014,932	$ 5.64	1,405,440	$ 86.59
January 1, 2013 – December 31, 2013	5,548,000	$ 5.32	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:

	Gas		Oil	
Contract Period	**MMBtu**	**Weighted Average Fixed Price**	**Bbls**	**Weighted Average Fixed Price**
VNG				
January 1, 2012 – December 31, 2012	—	$ —	91,500	$ 95.20
January 1, 2013 – December 31, 2013	—	$ —	68,600	$ 99.44
January 1, 2014 – December 31, 2014	1,277,500	$ 5.77	127,750	$ 95.00
January 1, 2015 – December 31, 2015	—	$ —	292,000	$ 95.63
ENP				
January 1, 2012 – December 31, 2012	—	$ —	—	$ —
January 1, 2013 – December 31, 2013	—	$ —	36,500	$ 105.00
January 1, 2014 – December 31, 2014	365,000	$ 5.40	—	$ —
January 1, 2015 – December 31, 2015	—	$ —	—	$ —
Consolidated				
January 1, 2012 – December 31, 2012	—	$ —	91,500	$ 95.20
January 1, 2013 – December 31, 2013	—	$ —	105,100	$ 101.37
January 1, 2014 – December 31, 2014	1,642,500	$ 5.69	127,750	$ 95.00
January 1, 2015 – December 31, 2015	—	$ —	292,000	$ 95.63

Collars

Production Period	Gas			Oil		
	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
VNG						
July 1, 2011 – December 31, 2011	975,200	$ 7.34	$ 8.44	18,400	$ 100.00	$ 116.20
January 1, 2012 – December 31, 2012	—	$ —	$ —	118,950	$ 90.77	$ 106.62
January 1, 2013 – December 31, 2013	—	$ —	$ —	82,125	$ 88.89	$ 107.34
January 1, 2014 – December 31, 2014	—	$ —	$ —	12,000	$ 100.00	$ 116.20
ENP						
July 1, 2011 – December 31, 2011	—	$ —	$ —	345,920	$ 80.00	$ 96.49
January 1, 2012 – December 31, 2012	—	$ —	$ —	475,800	$ 74.23	$ 90.98
Consolidated						
July 1, 2011 – December 31, 2011	975,200	$ 7.34	$ 8.44	364,320	$ 81.01	$ 97.49
January 1, 2012 – December 31, 2012	—	$ —	$ —	594,750	$ 77.54	$ 94.11
January 1, 2013 – December 31, 2013	—	$ —	$ —	82,125	$ 88.89	$ 107.34
January 1, 2014 – December 31, 2014	—	$ —	$ —	12,000	$ 100.00	$ 116.20

Three-Way Collars

Production Period	Oil			
	Bbls	Floor	Ceiling	Put Sold
VNG				
July 1, 2011 – December 31, 2011	19,125	$ 90.00	$ 103.50	$ 70.00
ENP				
July 1, 2011 – December 31, 2011	19,125	$ 90.00	$ 102.35	$ 70.00
Consolidated				
July 1, 2011 – December 31, 2011	38,250	$ 90.00	$ 102.93	$ 70.00

Puts

Contract Period	Gas	
	MMBtu	Weighted Average Fixed Price
ENP		
July 1, 2011 – December 31, 2011	625,232	$ 6.31
January 1, 2012 – December 31, 2012	328,668	$ 6.76

Put Spreads to be converted to Three-Way Collars (1)

		Oil	
Contract Period	**Bbls**	**Floor**	**Put Sold**
VNG			
January 1, 2012 – December 31, 2012	45,750	$ 90.00	$ 70.00
January 1, 2013 – December 31, 2013	45,625	$ 90.00	$ 70.00
ENP			
January 1, 2012 – December 31, 2012	45,750	$ 90.00	$ 70.00
January 1, 2013 – December 31, 2013	45,625	$ 90.00	$ 70.00
Consolidated			
January 1, 2012 – December 31, 2012	91,500	$ 90.00	$ 70.00
January 1, 2013 – December 31, 2013	91,250	$ 90.00	$ 70.00

(1) On July 7, 2011, we sold $120 calls on 125 Bbl/day for 2012-2013, establishing a Three-Way Collar.

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 June 30, 2011, we had open interest rate derivative contracts as follows (in thousands):

Period:	**Notional Amount**	**Fixed Libor Rates**
VNG		
July 1, 2011 to January 31, 2013	$ 20,000	2.38%
July 1, 2011 to December 10, 2014	$ 20,000	2.60%
July 1, 2011 to January 31, 2015	$ 40,000	1.75%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
ENP		
July 1, 2011 to March 7, 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).

	June 30, 2011	**December 31, 2010**
Assets:		
Commodity derivatives	$ 28,073	$ 33,435
Interest rate swaps	—	97
	$ 28,073	$ 33,532
Liabilities:		
Commodity derivatives	$ (85,848)	$ (48,008)
Interest rate swaps	(3,698)	(4,115)
	$ (89,546)	$ (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 $28.1 million at June 30, 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 June 30, 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Realized gains (losses):				
Other commodity derivatives	$ 1,193	$ 6,547	$ 2,572	$ 11,761
Interest rate swaps	(612)	(483)	(1,505)	(998)
	$ 581	$ 6,064	$ 1,067	$ 10,763
Unrealized gains (losses):				
Other commodity derivatives	$ 31,546	$ (90)	$ (41,014)	$ 10,720
Interest rate swaps	(803)	(434)	299	(684)
	$ 30,743	$ (524)	$ (40,715)	$ 10,036
Total gains (losses):				
Other commodity derivatives	$ 32,739	$ 6,457	$ (38,442)	$ 22,481
Interest rate swaps	(1,415)	(917)	(1,206)	(1,682)
	$ 31,324	$ 5,540	$ (39,648)	$ 20,799

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):

	June 30, 2011			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 6,146	$ —	$ 6,146
Interest rate derivative contracts	—	—	—	—
Total derivative instruments	$ —	$ 6,146	$ —	$ 6,146
Liabilities:				
Commodity price derivative contracts	$ —	$ (63,921)	$ —	$ (63,921)
Interest rate derivative contracts	—	(3,698)	—	(3,698)
Total derivative instruments	$ —	$ (67,619)	$ —	$ (67,619)

	December 31, 2010			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
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%); (4) the ten year average inflation factor (2.3%) and (5) the estimated cost for decommissioning the Elk Basin natural gas processing plant near Powell, Wyoming. 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 June 30 reported on our consolidated balance sheets and the changes in the asset retirement obligations for the six months ended June 30, were as follows (in thousands):

	2011	2010
Asset retirement obligations at January 1,	$ 30,202	$ 4,420
Liabilities added during the current period	406	514
Accretion expense	380	77
Retirements	(79)	—
Total asset retirement obligations at June 30,	30,909	5,011
Less: current obligations	(917)	—
Long-term Asset retirement obligation at June 30,	$ 29,992	$ 5,011

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 $0.5 million for each of the three months ended June 30, 2011 and 2010 and $0.9 million and $1.0 million for the six months ended June 30, 2011 and 2010, respectively. Costs incurred under the GCA were $0.4 million and $0.5 million for the three months ended June 30, 2011 and 2010, respectively, and $0.9 million and $0.8 million for the six months ended June 30, 2011 and 2010, respectively. A payable of $1.3 million and $0.6 million, respectively, is reflected on our June 30, 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”). 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 $2.05 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. The Administrative Fee was $2.06 per barrel of oil equivalent through March 31, 2011 and effective April 1, 2011 was decreased to $2.05 per barrel of oil equivalent. 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. During the three months ended June 30, 2011, VNG received administrative fees amounting to $1.6 million, Council of Petroleum Accountants Societies (“COPAS”) recovery amounting to $1.1 million and received reimbursements of third-party expenses amounting to $1.4 million. During the six months ended June 30, 2011, VNG received administrative fees amounting to $3.1 million, COPAS recovery amounting to $1.9 million and received reimbursements of third-party expenses amounting to $3.3 million.

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 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.

8. Commitments and Contingencies

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.

Additionally, the following pending litigation is outstanding related to the proposed merger with ENP. On March 29, 2011, John O'Neal, a purported unitholder of ENP filed a class action complaint in the 125th Judicial District of Harris County, Texas on behalf of unitholders of ENP. Similar actions were filed on April 4, 2011 by Jerry P. Morgan and on April 5, 2011 by Herbert F. Rower in other Harris County district courts. The *O'Neal, Morgan, and Rower* actions were consolidated on June 5, 2011 as *John O'Neal v. Encore Energy Partners, L.P., et al*., Case Number 2011-19340, which is pending in the 125th Judicial District Court of Harris County. On July 13, 2011, plaintiffs in the consolidated *O'Neal* action filed an amended putative class action complaint alleging breaches of fiduciary duty and aiding and abetting breach of fiduciary duty claims against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, VNG, Vanguard Acquisition Company, LLC, and Vanguard. Plaintiffs seek an injunction prohibiting the proposed merger from going forward and compensatory damages if the proposed merger is consummated. The defendants named in the Texas lawsuits intend to defend vigorously against them.

On April 5, 2011, Stephen Bushansky, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption *In re: Encore Energy Partners LP Unitholder Litigation,* C.A. No. 6347-VCP. On June 21, 2011, those plaintiffs jointly filed a consolidated class action complaint naming as defendants ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, and Vanguard. That putative class action complaint alleges, among other things, that defendants breached contractual duties owed to ENP's unitholders under the applicable partnership agreement by proposing and recommending the proposed merger. Plaintiffs seek an injunction prohibiting the proposed merger from going forward and compensatory damages if the proposed merger is consummated. In response, Vanguard has filed a motion to dismiss and it intends to defend vigorously against this lawsuit.

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

9. Common Units and Net Income per Unit

Basic earnings per unit is computed in accordance with ASC Topic 260 "*Earnings Per Share*" ("ASC Topic 260"), by dividing net income 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 June 30, 2011, we had two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on the NYSE under the symbol VNR and (ii) Class B units, issued to management and an employee as discussed in Note 10. *Unit-Based Compensation*. The Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic earnings per unit.

For the three and six months ended June 30, 2011, the 175,000 options granted to officers under the long-term incentive plan have been included in the computation of diluted earnings per unit as 63,578 and 65,571, respectively, additional common units that would have been issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period. For the three and six months ended June 30, 2010, these options were included in the computation of diluted earnings per unit as 15,909 additional common units that would have been 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 have also been included in the computation of earnings per unit for the three months ended June 30, 2011 as they had a dilutive effect and excluded for the six months ended June 30, 2011 as they had no dilutive effect. The 42,500 phantom units granted to officers during 2010 under our long-term incentive plan did not have a dilutive effect on earnings per unit for the three and six months ended June 30, 2010; 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 and six months ended June 30, 2011 and 2010 including each class of units issued and outstanding during the respective periods: common units and Class B units. Net income per unit is allocated to the common units and the Class B units on an equal basis.

10. 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 agreement 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. During the six months ended June 30, 2011, executives were granted restricted common units amounting to 62,500 units. 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 June 30, 2011, an accrued liability of $0.4 million has been recorded and non-cash unit-based compensation expense of $0.02 million has been recognized in the selling, general and administrative expenses line item in the consolidated statement of operations related to these phantom units for each of the three months ended June 30, 2011 and 2010, respectively, and $0.2 million and $0.05 million for the six months ended June 30, 2011 and 2010, respectively.

During the first six months of 2011, VNR employees were granted a total of 112,210 common units which will 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. In May 2011, four board members were granted 11,884 common units which will vest one year from the date of grant.

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 June 30, 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	186,594	$ 28.87
Forfeited	(4,315)	$ (28.97)
Vested	(27,719)	$ (22.53)
Non-vested units at June 30, 2011	221,279	$ 27.65

At June 30, 2011, there was approximately $5.4 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.7 years. Our consolidated statements of operations reflect non-cash compensation of $0.7 million and $0.2 million in the selling, general and administrative expenses line item for the three months ended June 30, 2011 and 2010, respectively, and $1.4 million and $0.5 million for the six months ended June 30, 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.

In February 2011, ENP issued 7,980 units under the LTIP to three of the members of the Board of Directors which will vest within one year but have distribution equivalent rights that provide the Board members with a bonus equal to the distribution on unvested units. The fair value of these units was approximately $0.2 million on the date of grant.

These common units and restricted 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 June 30, 2011 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2010	—	$ —
Granted	147,987	$ 22.25
Forfeited	—	$ —
Vested	—	$ —
Non-vested units at June 30, 2011	147,987	$ 22.25

As of June 30, 2011, there was approximately $2.8 million of unrecognized compensation cost related to ENP's non-vested restricted units, which is expected to be recognized over a period of approximately 2.6 years. The Consolidated Statements of Operations reflects non-cash compensation of $0.2 million and $0.4 million in "Selling general and administrative expenses" for the three and six months ended June 30, 2011, respectively. As of June 30, 2011, there were 927,013 common units available for issuance under the LTIP.

11. 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 June 30, 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 June 30, 2011, we had approximately $62.6 million and $678.8 million remaining available under our 2009 and 2010 shelf registration statements, respectively.

12. Subsequent Events

On June 22, 2011, pursuant to two Purchase and Sale Agreements (the "Purchase Agreements"), we and ENP agreed to acquire producing oil and natural gas assets in the Permian Basin in West Texas (the "Purchased Assets") from an undisclosed seller. We and ENP each agreed to purchase 50% of the Purchased Assets for $42.5 million and each paid the seller a non-refundable deposit of $4.25 million. In July 2011, we requested an interim redetermination of our borrowing base under our reserve-based credit facility which resulted in an increase of our borrowing base to $265.0 million. The effective date of this acquisition is May 1, 2011. This acquisition was completed on July 29, 2011 for an aggregate adjusted purchase price of $81.4 million, subject to customary post-closing adjustments to be determined. The purchase price was funded with borrowings under our reserve-based credit facility and ENP's Credit Agreement.

On July 11, 2011, Vanguard and ENP announced the execution of a definitive agreement that would result in a merger whereby ENP would become a wholly-owned subsidiary of VNG, through a unit-for-unit exchange. Under the terms of the definitive agreement, ENP's public unitholders would receive 0.75 Vanguard common units in exchange for each ENP common unit they own at closing. The transaction would result in approximately 18.4 million additional common units being issued by Vanguard. The terms of the definitive agreement were unanimously approved by the members of the ENP Conflicts Committee, who negotiated the terms on behalf of ENP and is comprised solely of independent directors. In addition, Jefferies & Company, Inc., has issued a fairness opinion to the ENP Conflicts Committee stating that they believe the exchange ratio is fair, from a financial point of view, to the unaffiliated unitholders of ENP. The members of the Vanguard Conflicts Committee, which is also comprised solely of independent directors, negotiated the terms on behalf of Vanguard and also voted unanimously in favor of the merger. In addition, RBC Capital Markets has issued a fairness opinion to the Vanguard Conflicts Committee stating that they believe the exchange ratio is fair, from a financial point of view, to Vanguard.

The completion of the merger is subject to approval by a majority of the outstanding ENP common unitholders and also subject to the approval of the issuance of additional Vanguard common units in connection with the merger by the affirmative vote of a majority of the votes by Vanguard unitholders. Completion of the merger, assuming the requisite unitholder votes are obtained and subject to other customary terms and conditions, is expected to occur during the fourth quarter of 2011. On August 2, 2011, Vanguard and ENP filed a Registration Statement on Form S-4 with the SEC, which has not been declared effective. The Registration Statement incorporates a joint proxy statement/prospectus which Vanguard and ENP plan to mail to their respective unitholders in connection with obtaining unitholder approval of the proposed merger. Pending completion of the merger, Vanguard and ENP have agreed to customary restrictions in the way they conduct their business.

On July 26, 2011, the board of directors declared a cash distribution attributable to the second quarter of 2011 of $0.575 per unit expected to be paid on August 12, 2011 to Vanguard unitholders of record as of the close of business on August 5, 2011.

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, our Quarterly Report on Form 10-Q for the three months ended March 31, 2011 and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the Securities and Exchange Commission ("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 reserves. 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 June 30, 2011, we owned working interests in 4,931 gross (2,300 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 six months ended June 30, 2011 was 4,721 BOE per day and 13,279 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. Our average net production for the six months ended June 30, 2011 includes production from the properties acquired in connection with the Encore Acquisition and are subject to a 53.4% non-controlling interest in ENP. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. As of June 30, 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 June 30, 2011, based on internal reserve estimates, approximately 19% or 12.8 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 (as described below) 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 interests 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 46.6% aggregate equity interest in ENP at June 30, 2011. As consideration for the purchase, we paid $300.0 million in cash and issued 3,137,255 VNR common units, valued at $93.0 million.

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 $2.05 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. The Administrative Fee was $2.06 per barrel of oil equivalent through March 31, 2011 and effective April 1, 2011 was decreased to $2.05 per barrel of oil equivalent. 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 July 11, 2011, Vanguard and ENP announced the execution of a definitive agreement that would result in a merger whereby ENP would become a wholly-owned subsidiary of VNG, through a unit-for-unit exchange. Under the terms of the definitive agreement, ENP’s public unitholders would receive 0.75 Vanguard common units in exchange for each ENP common unit they own at closing. The transaction would result in approximately 18.4 million additional common units being issued by Vanguard. The terms of the definitive agreement were unanimously approved by the members of the ENP Conflicts Committee, who negotiated the terms on behalf of ENP and is comprised solely of independent directors. In addition, Jefferies & Company, Inc., has issued a fairness opinion to the ENP Conflicts Committee stating that they believe the exchange ratio is fair, from a financial point of view, to the unaffiliated unitholders of ENP. The members of the Vanguard Conflicts Committee, which is also comprised solely of independent directors, negotiated the terms on behalf of Vanguard and also voted unanimously in favor of the merger. In addition, RBC Capital Markets has issued a fairness opinion to the Vanguard Conflicts Committee stating that they believe the exchange ratio is fair, from a financial point of view, to Vanguard.

The completion of the merger is subject to approval by a majority of the outstanding ENP common unitholders and also subject to the approval of the issuance of additional Vanguard common units in connection with the merger by the affirmative vote of a majority of the votes by Vanguard unitholders. Completion of the merger, assuming the requisite unitholder votes are obtained and subject to other customary terms and conditions, is expected to occur during the fourth quarter of 2011. On August 2, 2011, Vanguard and ENP filed a Registration Statement on Form S-4 with the SEC, which has not been declared effective. The Registration Statement incorporates a joint proxy statement/prospectus which Vanguard and ENP plan to mail to their respective unitholders in connection with obtaining unitholder approval of the proposed merger. Pending completion of the merger, Vanguard and ENP have agreed to customary restrictions in the way they conduct their business.

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 June 30, 2011, based on internal reserve estimates, these acquired properties had estimated proved reserves of 3.5 MMBOE, 97% of which is oil and 69% is proved developed.

Newfield Acquisition

On April 28, 2011, we entered into a Purchase and Sale Agreement with a private seller, for the acquisition of certain oil and natural gas properties located in Texas and New Mexico. We refer to this acquisition as the "Newfield Acquisition." The purchase price for said assets was $9.1 million with an effective date of April 1, 2011. We completed this acquisition on May 12, 2011 for an adjusted purchase price of $9.2 million, subject to customary post-closing adjustments to be determined. This acquisition was funded with borrowings under the Company's existing reserve-based credit facility.

Recent Acquisition

On June 22, 2011, pursuant to two Purchase and Sale Agreements (the "Purchase Agreements"), we and ENP agreed to acquire producing oil and natural gas assets in the Permian Basin in West Texas (the "Purchased Assets") from an undisclosed seller. We and ENP each agreed to purchase 50% of the Purchased Assets for $42.5 million and each paid the seller a non-refundable deposit of $4.25 million. In July 2011, we requested an interim redetermination of our borrowing base under our reserve-based credit facility which resulted in an increase of our borrowing base to $265.0 million. The effective date of this acquisition is May 1, 2011. This acquisition was completed on July 29, 2011 for an aggregate adjusted purchase price of $81.4 million, subject to customary post-closing adjustments to be determined. The purchase price was funded with borrowings under our reserve-based credit facility and ENP's Credit Agreement. The interests acquired, including the proved reserves attributable to the approximate 53.4% non-controlling interest in ENP, have estimated total net proved reserves of 5.5 million barrels of oil equivalent, of which approximately 70% are oil and natural gas liquids reserves and are 100% 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 six months ended June 30, 2011, we drilled seven gross (2.9 net) non-operated wells and completed six gross (2.3 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 June 30,		Six Months Ended June 30,	
	2011	**2010(a)(b)**	**2011**	**2010(a)(b)**
Revenues:				
Oil sales	$ 62,232	$ 11,022	$ 118,322	$ 20,688
Natural gas sales	12,201	6,386	23,215	13,904
Natural gas liquids sales	5,938	2,038	10,873	4,924
Oil, natural gas and natural gas liquids sales	**80,371**	**19,446**	**152,410**	**39,516**
Loss on commodity cash flow hedges	(601)	(517)	(1,672)	(1,559)
Realized gain on other commodity derivative contracts	1,193	6,547	2,572	11,761
Unrealized gain (loss) on other commodity derivative contracts	31,546	(90)	(41,014)	10,720
Total revenues	**$ 112,509**	**$ 25,386**	**$ 112,296**	**$ 60,438**
Costs and expenses:				
Production:				
Lease operating expenses	$ 15,667	$ 4,634	$ 28,567	$ 8,707
Production taxes and marketing	7,404	1,880	13,626	3,462
Depreciation, depletion, amortization, and accretion	21,551	5,713	41,378	9,951
Selling, general and administrative expenses	6,799	1,134	11,107	2,534
Total costs and expenses	**$ 51,421**	**$ 13,361**	**$ 94,678**	**$ 24,654**
Other income (expense):				
Interest expense	$ (6,841)	$ (1,523)	$ (13,628)	$ (2,814)
Realized loss on interest rate derivative contracts	$ (612)	$ (483)	$ (1,505)	$ (998)
Unrealized gain (loss) on interest rate derivative contracts	$ (803)	$ (434)	$ 299	$ (684)
Loss on acquisition of natural gas and oil properties	$ (870)	$ (5,680)	$ (870)	$ (5,680)
Other	$ 8	$ —	$ 6	$ —

(a) The Parker Creek Acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the three or six month periods ended June 30, 2010.

(b) The Encore Acquisition closed on December 31, 2010 and, as such, no operations are included in the three or six month periods ended June 30, 2010.

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

Revenues

Oil, natural gas and natural gas liquids sales increased $60.9 million to $80.4 million during the three months ended June 30, 2011 as compared to the same period in 2010. The key revenue measurements were as follows:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010(a)(b)	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	689	747	(8)%
Permian gas (MMcf)	75	82	(8)%
South Texas gas (MMcf)	464	437	6%
ENP gas (MMcf)	1,455	—	—
Total natural gas production (MMcf)	2,683	1,266	112%
Average Appalachian daily gas production (Mcf/day)	7,566	8,210	(8)%
Average Permian daily gas production (Mcf/day)	828	903	(8)%
Average South Texas daily gas production (Mcf/day)	5,104	4,799	6%
Average ENP daily gas production (Mcf/day)	15,984	—	—
Average daily gas production (Mcf/day)	29,482	13,912	112%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$6.99(c)	$ 10.09(c)	(31)%
Net realized gas price, excluding hedges	$4.55	$ 5.04	(10)%
Net Oil Production:			
Appalachian oil (Bbls)	22,842	28,974	(21)%
Permian oil (Bbls)	99,611	91,817	8%
South Texas oil (Bbls)	5,684	6,818	(17)%
Mississippi oil (Bbls)	46,985	26,836	75%
ENP oil (Bbls)	495,419	—	—
Total oil production (Bbls)	670,541	154,445	334%
Average Appalachian daily oil production (Bbls/day)	251	318	(21)%
Average Permian daily oil production (Bbls/day)	1,094	1,009	8%
Average South Texas daily oil production (Bbls/day)	62	75	(17)%
Average Mississippi daily oil production (Bbls/day)	516	295	75%
Average ENP daily oil production (Bbls/day)	5,444	—	—
Average daily oil production (Bbls/day)	7,367	1,697	334%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$84.66(c)	$ 75.87(c)	12%
Net realized oil price, excluding hedges	$92.76	$ 71.37	30%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Bbls)	12,189	7,253	68%
South Texas natural gas liquids (Bbls)	40,371	43,070	(6)%
ENP natural gas liquids (Bbls)	38,764	—	—
Total natural gas liquids production (Bbls)	91,324	50,323	81%
Average Permian daily natural gas liquids production (Bbls/day)	134	80	68%
Average South Texas daily natural gas liquids production (Bbls/day)	444	473	(6)%
Average ENP daily natural gas liquids production (Bbls/day)	426	—	—
Average daily natural gas liquids production (Bbls/day)	1,004	553	81%
Average Net Realized Natural Gas Liquids Sales Price per Bbl	$65.02	$40.32	61%

(a) The Parker Creek Acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the three month periods ended June 30, 2010.

(b) The Encore Acquisition closed on December 31, 2010 and, as such, no operations are included in the three month period endeds June 30, 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 June 30, 2011 compared to the same period in 2010 was due primarily to the increases in production from our acquisitions. We experienced a 30% increase in the average realized oil price, excluding hedges, and a 10% decrease in the average realized natural gas sales price received, excluding hedges. Oil revenues increased 465% from $11.0 million during the three months ended June 30, 2010 to $62.2 million during the same period in 2011 as a result of a $21.39 per Bbl increase in our average realized oil price, excluding hedges, and a 516.1 MBbls increase in our oil production volumes. Our higher average realized oil price was primarily due to a higher average NYMEX price, which increased from $78.12 per Bbl in the second quarter of 2010 to $102.56 per Bbl in the second quarter of 2011. Natural gas revenues increased 91% from $6.4 million during the three months ended June 30, 2010 to $12.2 million during the same period in 2011 as a result of a 112% increase in our natural gas production volumes from the wells acquired in the Encore Acquisition. The impact of the increase in our natural gas production volumes was offset by a $0.49 per Mcf decrease in our average realized natural gas price, excluding hedges, primarily due to a lower average NYMEX price, which decreased from $4.35 per Mcf in the second quarter of 2010 to $4.31 per Mcf in the second quarter of 2011. Additionally, our total production increased by 191% on a BOE basis. The increase in production for the three months ended June 30, 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 55%, 37% and 8%, respectively, of our production during the three months ended June 30, 2011 compared to crude oil, natural gas, and natural gas liquids of 37%, 51% and 12%, respectively, during the same period in 2010.

Hedging and Price Risk Management Activities

During the three months ended June 30, 2011, the Company recognized a $1.2 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $31.5 million gain related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. These realized and unrealized gains resulted from the changes in commodity prices and the effect of these price changes is discussed in the paragraph below. During the three months ended June 30, 2011 and 2010, the Company recognized $0.6 million and $0.5 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 June 30, 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 by us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because the majority of our hedges are not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our consolidated 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 increased by $11.0 million to $15.7 million for the three months ended June 30, 2011 as compared to the three months ended June 30, 2010, of which $10.7 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 and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $5.5 million for the three months ended June 30, 2011 as compared to the same period in 2010. Severance taxes increased by $5.1 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 by approximately $15.8 million to $21.6 million for the three months ended June 30, 2011 from approximately $5.7 million for the three months ended June 30, 2010 due primarily to approximately $15.1 million and $1.9 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 June 30, 2011 increased $5.7 million as compared to the three months ended June 30, 2010 principally due to approximately $2.1 million in incremental costs related to ENP, a $0.5 million increase in non-cash compensation charges related to the grant of units to employees and the grant of phantom units to officers, a $2.0 million increase in compensation related expenses and a $1.1 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 June 30, 2011 compared to $1.5 million for the three months ended June 30, 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 June 30, 2011.

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Revenues

Oil, natural gas and natural gas liquids sales increased $112.9 million to $152.4 million during the six months ended June 30, 2011 as compared to the same period in 2010. The key revenue measurements were as follows:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010(a)(b)	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	1,315	1,436	(8)%
Permian gas (MMcf)	191	179	7%
South Texas gas (MMcf)	866	860	1%
ENP gas (MMcf)	2,838	—	—
Total natural gas production (MMcf)	5,210	2,475	111%
Average Appalachian daily gas production (Mcf/day)	7,265	7,935	(8)%
Average Permian daily gas production (Mcf/day)	1,054	990	7%
Average South Texas daily gas production (Mcf/day)	4,786	4,750	1%
Average ENP daily gas production (Mcf/day)	15,678	—	—
Average daily gas production (Mcf/day)	28,783	13,675	111%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$7.14(c)	$ 10.10(c)	(29)%
Net realized gas price, excluding hedges	$4.46	$ 5.62	(21)%
Net Oil Production:			
Appalachian oil (Bbls)	48,473	61,330	(21)%
Permian oil (Bbls)	211,006	188,238	12%
South Texas oil (Bbls)	10,992	10,452	5%
Mississippi oil (Bbls)	99,730	26,836	272%
ENP oil (Bbls)	985,386	—	—
Total oil production (Bbls)	1,355,587	286,856	373%
Average Appalachian daily oil production (Bbls/day)	268	339	(21)%
Average Permian daily oil production (Bbls/day)	1,166	1,040	12%
Average South Texas daily oil production (Bbls/day)	61	57	7%
Average Mississippi daily oil production (Bbls/day)	551	148	272%
Average ENP daily oil production (Bbls/day)	5,444	—	—
Average daily oil production (Bbls/day)	7,490	1,584	373%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$81.22(c)	$ 76.52(c)	6%
Net realized oil price, excluding hedges	$87.23	$ 72.12	21%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Bbls)	19,824	16,297	22%
South Texas natural gas liquids (Bbls)	79,929	91,103	(12)%
ENP natural gas liquids (Bbls)	79,931	—	—
Total natural gas liquids production (Bbls)	179,684	107,400	67%
Average Permian daily natural gas liquids production (Bbls/day)	110	90	22%
Average South Texas daily natural gas liquids production (Bbls/day)	441	503	(12)%
Average ENP daily natural gas liquids production (Bbls/day)	442	—	—
Average daily natural gas liquids production (Bbls/day)	993	593	67%
Average Net Realized Natural Gas Liquids Sales Price per Bbl	$60.51	$45.78	32%

(a) The Parker Creek Acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the six month periods ended June 30, 2010.
(b) The Encore Acquisition closed on December 31, 2010 and, as such, no operations are included in the six month periods ended June 30, 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 six months ended June 30, 2011 compared to the same period in 2010 was due primarily to the increases in production from our acquisitions. We experienced a 21% increase in the average realized oil price, excluding hedges, and a 21% decrease in the average realized natural gas sales price received, excluding hedges. Oil revenues increased 472% from $20.7 million during the six months ended June 30, 2010 to $118.3 million during the same period in 2011 as a result of a $15.11 per Bbl increase in our average realized oil price, excluding hedges, and a 1,068.7 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 $78.37 per Bbl in the first six months of 2010 to $98.33 per Bbl in the first six months of 2011. However, we did not reap the entire benefit of the 25% increase in the NYMEX oil price due to significant widening of the basis differential received on our oil. Natural gas revenues increased 67% from $13.9 million during the six months ended June 30, 2010 to $23.2 million during the same period in 2011 as a result of a 111% increase in our natural gas production volumes from the wells acquired in the Encore Acquisition. The impact of the increase in our natural gas production volumes was offset by a $1.16 per Mcf decrease in our average realized natural gas price, excluding hedges, primarily due to a lower average NYMEX price, which decreased from $4.69 per Mcf in the first six months of 2010 to $4.21 per Mcf in the first six months of 2011. Additionally, our total production increased by 198% on a BOE basis. The increase in production for the six months ended June 30, 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%, 36% and 7%, respectively, of our production during the six months ended June 30, 2011 compared to crude oil, natural gas, and natural gas liquids of 36%, 51% and 13%, respectively, during the same period in 2010.

Hedging and Price Risk Management Activities

During the six months ended June 30, 2011, the Company recognized a $2.6 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $41.0 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 six months ended June 30, 2011 and 2010, the Company recognized $1.7 million and $1.6 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 six months ended June 30, 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 by us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because the majority of our hedges are not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our consolidated 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 increased by $19.9 million to $28.6 million for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010, of which $18.7 million related primarily to the Encore Acquisition and $1.0 million related to increased lease operating expenses for wells acquired in the Parker Creek Acquisition.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production taxes increased by $10.2 million for the six months ended June 30, 2011 as compared to the same period in 2010. Severance taxes increased by $8.9 million as a result of increased oil, natural gas and natural gas liquids sales due to the Encore Acquisition. Ad valorem taxes increased by $1.1 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 $41.4 million for the six months ended June 30, 2011 from approximately $10.0 million for the six months ended June 30, 2010 due primarily to approximately $29.8 million and $3.4 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 six months ended June 30, 2011 increased $8.6 million as compared to the six months ended June 30, 2010 principally due to approximately $3.7 million in incremental costs related to ENP, a $0.9 million increase in non-cash compensation charges related to the grant of units to employees and the grant of phantom units to officers, a $2.0 million increase in compensation related expenses and a $2.1 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 $13.6 million for the six months ended June 30, 2011 compared to $2.8 million for the six months ended June 30, 2010 primarily due to approximately $5.1 million of interest expense on the Term Loan borrowed in connection with the Encore Acquisition, $4.4 million of interest expense incurred for ENP's Credit Agreement and higher average outstanding debt under our reserve-based credit facility during the six months ended June 30, 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 June 30, 2011, our critical accounting policies were 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 VNR's reserve-based credit facility or ENP's Credit Agreement and publicly offered equity or debt, depending on market conditions. After taking into consideration the interim redetermination of our borrowing base which resulted in an increase of our borrowing base to $265.0 million and the funding of the recently closed acquisition in the Permian Basin, as of August 4, 2011, we had $48.5 million and $146.0 million available to be borrowed under Vanguard's reserve-based credit facility and under ENP's Credit Agreement, respectively.

The borrowing bases are subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future oil, natural gas and 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. If our outstanding borrowings under VNR's 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 matures on March 7, 2012; therefore, all outstanding borrowings under the ENP Credit Agreement are reflected as a current liability on the balance sheet. In July 2011, Vanguard began the syndication of a new credit facility that would retire all of the outstanding debt of ENP and the $175.0 million on year Term Loan upon the consummation of a merger with Vanguard. In the event that the merger is not consummated, we will continue to evaluate our options which, based on discussions with lenders, include extending the term of the ENP revolving credit facility or refinancing under a new revolving credit facility.

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

Cash Flow from Operations

Net cash provided by operating activities was $84.8 million during the six months ended June 30, 2011, compared to $31.5 million during the six months ended June 30, 2010. The increase in cash provided by operating activities during the six months ended June 30, 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 $8.5 million in 2011 compared to decreasing total cash flows by $3.0 million in 2010. Contributing to the decrease in working capital during 2011 was a $4.7 million increase in accounts receivable resulting from the timing of collections and a $3.4 million decrease in accounts payable, oil and natural gas revenue payable and accrued expenses that resulted primarily from the timing effects of payments for transaction costs related to the Encore Acquisition and compensation related amounts and the timing of payment for invoices. Unrealized derivative gains and losses are non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the six months ended June 30, 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, puts, swaptions, put spreads, NYMEX collars and three-way 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 $27.0 million for the six months ended June 30, 2011, compared to $121.1 million during the same period in 2010. Cash used in investing activities during the first six months of 2011 was primarily attributable to $8.7 million for the drilling and development of oil and natural gas properties, $12.0 million for the acquisition of oil and natural gas properties, primarily in the Newfield Acquisition, and $10.7 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties, offset by $5.0 million in proceeds from the divestiture of certain oil and natural gas properties in the Permian Basin. Cash used in investing activities during the first six months of 2010 included $112.3 million for the acquisition of natural gas and oil properties in the Parker Creek acquisition, $7.6 million for the drilling and development of natural gas and oil properties and $0.9 million for prepayments for the drilling and development of natural gas and oil properties.

Cash Flow from Financing Activities

Cash used in financing activities was approximately $54.2 million for the six months ended June 30, 2011, compared to cash provided by financing activities of $91.4 million for the six months ended June 30, 2010. During the six months ended June 30, 2011, total net proceeds from borrowings under our financing arrangements were $4.5 million. Additionally, cash of $34.1 million was used in distributions to unitholders and $24.3 million in ENP's distributions to non-controlling interest. Cash provided by financing activities during the six months ended June 30, 2010 included $41.9 million in net borrowings under our reserve-based credit facility and proceeds from our public equity offering completed in May 2010 of $71.4 million. Offsetting the cash provided by financing activities during the six months ended June 30, 2010 was cash used of $19.8 million for distributions to unitholders.

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 included 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. 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. At June 30, 2011, we had $185.0 million outstanding under our reserve-based credit facility and the applicable margins and other fees will 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. 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. In July 2011, in connection with our recent acquisition in the Permian Basin, we requested an interim redetermination of our borrowing base under our reserve-based credit facility which resulted in an increase of our borrowing base to $265.0 million. After taking into consideration the funding of the recently closed acquisition in the Permian Basin, as of August 4, 2011, we had $48.5 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 June 30, 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 June 30, 2011, we were in compliance with all covenants under our reserve-based credit facility. 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 LIBOR 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 six months' duration, each day prior to the last day of such interest period that occurs at intervals of six months' duration after the first day of such interest period and accrues at a rate per annum of 5.50% plus the Adjusted LIBOR 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 June 30, 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 June 30, 2011. In July 2011, Vanguard began the syndication of a new credit facility that would retire all of the outstanding debt of ENP upon the consummation of a merger with Vanguard. In the event that the merger is not consummated, we will continue to evaluate our options which, based on discussions with lenders, include extending the term of the ENP revolving credit facility or refinancing under a new revolving credit facility.

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 $400.0 million, which is redetermined semi-annually and upon requested special redeterminations. As of June 30, 2011, there were $230.0 million of outstanding borrowings and $170.0 million of borrowing capacity under the Credit Agreement. After taking into consideration the funding of the recently closed acquisition in the Permian Basin, as of August 4, 2011, there were $254.0 million of outstanding borrowings and $146.0 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, six, 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 June 30, 2011, we were in compliance with all covenants under ENP's Credit Agreement.

Off-Balance Sheet Arrangements

At June 30, 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 June 30, 2011, there were no loss contingencies.

The following pending litigation is outstanding related to the proposed merger with ENP. On March 29, 2011, John O'Neal, a purported unitholder of ENP filed a class action complaint in the 125th Judicial District of Harris County, Texas on behalf of unitholders of ENP. Similar actions were filed on April 4, 2011 by Jerry P. Morgan and on April 5, 2011 by Herbert F. Rower in other Harris County district courts. The *O'Neal, Morgan, and Rower* actions were consolidated on June 5, 2011 as *John O'Neal v. Encore Energy Partners, L.P., et al*., Case Number 2011-19340, which is pending in the 125th Judicial District Court of Harris County. On July 13, 2011, plaintiffs in the consolidated *O'Neal* action filed an amended putative class action complaint alleging breaches of fiduciary duty and aiding and abetting breach of fiduciary duty claims against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, VNG, Vanguard Acquisition Company, LLC, and Vanguard. Plaintiffs seek an injunction prohibiting the proposed merger from going forward and compensatory damages if the proposed merger is consummated. The defendants named in the Texas lawsuits intend to defend vigorously against them.

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

Commitments and Contractual Obligations

A summary of our contractual obligations as of June 30, 2011 is provided in the following table (in thousands):

	Payments Due by Year						
	2011	2012	2013	2014	2015	After 2015	Total
Management base salaries	$ 415	$ 830	$ 97	$ —	$ —	$ —	$ 1,342
Asset retirement obligations (1)	917	858	1,004	622	447	27,061	30,909
Derivative liabilities (2)	10,005	32,179	22,002	19,130	6,230	—	89,546
Financing arrangements (3)	175,000	415,000	—	—	—	—	590,000
Operating leases	857	932	251	—	—	—	2,040
Development commitments (4)	890	—	—	—	—	—	890
Total	$ 188,084	$ 449,799	$ 23,354	$ 19,752	$ 6,677	$ 27,061	$ 714,727

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

(2) Represents liabilities for commodity and interest rate derivative contracts, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read "Item 3—Quantitative and Qualitative Disclosures About Market Risk" and Note 4 of the Notes to the Consolidated Financial Statements included in Item 1. Unaudited Financial Statements for additional information regarding our commodity and interest rate derivative contracts.

(3) This table does not include interest to be paid on the principal balances shown as the interest rates on our financing arrangements are variable. Please read Note 3 of the Notes to the Consolidated Financial Statements included in Item 1. Unaudited Financial Statements for additional information regarding our long-term debt.

(4) Represents authorized purchases for work in process.

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income attributable to Vanguard unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income attributable to Vanguard unitholders plus net income attributable to the non-controlling interest. The result is net income 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;
- Loss on acquisition of natural gas and oil properties;
- Deferred taxes;
- Unit-based compensation expense;
- Fair value of phantom units granted to officers;
- Material transaction costs incurred on acquisitions and mergers;
- 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 June 30, 2011 as compared to the three months ended June 30, 2010, Adjusted EBITDA attributable to Vanguard unitholders increased 90%, from $19.1 million to $36.5 million. For the six months ended June 30, 2011 as compared to the six months ended June 30, 2010, Adjusted EBITDA attributable to Vanguard unitholders increased 97%, from $37.6 million to $74.1 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income attributable to Vanguard unitholders	$ 31,799	$ 3,905	$ 1,387	$ 25,608
Net income attributable to non-controlling interest	20,171	—	533	—
Net income	51,970	3,905	1,920	25,608
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	7,453	2,006	15,133	3,812
Depreciation, depletion, amortization and accretion	21,551	5,713	41,378	9,951
Amortization of premiums paid on derivative contracts	471	493	4,838	998
Amortization of value on derivative contracts acquired	66	558	118	1,168
Unrealized (gains) losses on other commodity and interest rate derivative contracts	(30,743)	524	40,715	(10,036)
Loss on acquisition of natural gas and oil properties	870	5,680	870	5,680
Deferred taxes	83	31	195	(49)
Unit-based compensation expense	667	212	1,146	466
Fair value of phantom units granted to officers	21	21	233	48
Material transaction costs incurred on acquisitions and mergers	563	—	563	—
Adjusted EBITDA before non-controlling interest	52,972	19,143	107,109	37,646
Non-controlling interest attributable to adjustments above	(17,239)	—	(34,499)	—
Administrative services fees eliminated in consolidation	727	—	1,467	—
Adjusted EBITDA attributable to Vanguard unitholders	$ 36,460	$ 19,143	$ 74,077	$ 37,646

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 (“WTI”) 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. We also may enter into three-way collar contracts which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price of NYMEX WTI crude oil drops below the price of the short put. This allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. We temporarily enter into put spreads which combine a long put with a short put, with the intention of adding a short call to convert them into three-way collars. We also enter into swaption agreements, under which we provide options to counterparties to extend swap contracts into subsequent years. In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management’s view on future commodity pricing. The amount of oil and natural gas production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Typically, management intends to hedge 75% to 85% of projected production for a six 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 June 30, 2011, the fair value of commodity derivative contracts was a liability of approximately $57.8 million, of which $5.0 million settles during the next twelve months.

The following table summarizes commodity derivative contracts in place at June 30, 2011:

	July 1, - December 31, 2011	Year 2012	Year 2013
Gas Positions:			
Fixed Price Swaps:			
VNG			
Notional Volume (MMBtu)	1,642,052	1,281,000	2,190,000
Weighted Average Fixed Price ($/MMBtu)	$ 7.81	$ 5.45	$ 5.62
ENP			
Notional Volume (MMBtu)	1,877,168	3,733,932	3,358,000
Weighted Average Fixed Price ($/MMBtu)	$ 6.06	$ 5.70	$ 5.12
Consolidated			
Notional Volume (MMBtu)	3,519,220	5,014,932	5,548,000
Weighted Average Fixed Price ($/MMBtu)	$ 6.88	$ 5.64	$ 5.32
Collars:			
VNG			
Notional Volume (MMBtu)	975,200	—	—
Floor Price ($/MMBtu)	$ 7.34	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.44	$ —	$ —
Puts:			
ENP			
Notional Volume (MMBtu)	625,232	328,668	—
Weighted Average Fixed Price ($/MMBtu)	$ 6.31	$ 6.76	$ —
Total Gas Positions:			
VNG			
Notional Volume (MMBtu)	2,617,252	1,281,000	2,190,000
ENP			
Notional Volume (MMBtu)	2,502,400	4,062,600	3,358,000
Consolidated			
Notional Volume (MMBtu)	5,119,652	5,343,600	5,548,000

	July 1, - December 31, 2011	Year 2012	Year 2013	Year 2014
Oil Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (Bbls)	254,900	420,900	305,400	209,875
Weighted Average Fixed Price ($/Bbl)	$ 90.05	$ 92.42	$ 90.26	$ 94.37
ENP				
Notional Volume (Bbls)	279,340	984,540	1,295,750	1,168,000
Weighted Average Fixed Price ($/Bbl)	$ 82.90	$ 84.10	$ 88.95	$ 88.95
Consolidated				
Notional Volume (Bbls)	534,240	1,405,440	1,601,150	1,377,875
Weighted Average Fixed Price ($/Bbl)	$ 86.31	$ 86.59	$ 89.20	$ 89.78
Collars:				
VNG				
Notional Volume (Bbls)	18,400	118,950	82,125	12,000
Floor Price ($/Bbl)	$ 100.00	$ 90.77	$ 88.89	$ 100.00
Ceiling Price ($/Bbl)	$ 116.20	$ 106.62	$ 107.34	$ 116.20
ENP				
Notional Volume (Bbls)	345,920	475,800	—	—
Floor Price ($/Bbl)	$ 80.00	$ 74.23	$ —	$ —
Ceiling Price ($/Bbl)	$ 96.49	$ 90.98	$ —	$ —
Consolidated				
Notional Volume (Bbls)	364,320	594,750	82,125	12,000
Floor Price ($/Bbl)	$ 81.01	$ 77.54	$ 88.89	$ 100.00
Ceiling Price ($/Bbl)	$ 97.49	$ 94.11	$ 107.34	$ 116.20
Put Spreads to be converted to Three-Way Collars (1):				
VNG				
Notional Volume (Bbls)	—	45,750	45,625	—
Floor Price ($/Bbl)	$ —	$ 90.00	$ 90.00	$ —
Put Sold Price ($/Bbl)	$ —	$ 70.00	$ 70.00	$ —
ENP				
Notional Volume (Bbls)	—	45,750	45,625	—
Floor Price ($/Bbl)	$ —	$ 90.00	$ 90.00	$ —
Put Sold Price ($/Bbl)	$ —	$ 70.00	$ 70.00	$ —
Consolidated				
Notional Volume (Bbls)	—	91,500	91,250	—
Floor Price ($/Bbl)	$ —	$ 90.00	$ 90.00	$ —
Put Sold Price ($/Bbl)	$ —	$ 70.00	$ 70.00	$ —
Three-Way Collars:				
VNG				
Notional Volume (Bbls)	19,125	—	—	—
Floor Price ($/Bbl)	$ 90.00	$ —	$ —	$ —
Ceiling Price ($/Bbl)	$ 103.50	$ —	$ —	$ —
Put Sold Price ($/Bbl)	$ 70.00	$ —	$ —	$ —
ENP				
Notional Volume (Bbls)	19,125	—	—	—
Floor Price ($/Bbl)	$ 90.00	$ —	$ —	$ —
Ceiling Price ($/Bbl)	$ 102.35	$ —	$ —	$ —
Put Sold Price ($/Bbl)	$ 70.00	$ —	$ —	$ —
Consolidated				
Notional Volume (Bbls)	38,250	—	—	—
Floor Price ($/Bbl)	$ 90.00	$ —	$ —	$ —
Ceiling Price ($/Bbl)	$ 102.93	$ —	$ —	$ —
Put Sold Price ($/Bbl)	$ 70.00	$ —	$ —	$ —
Total Oil Positions:				
VNG				
Notional Volume (Bbls)	292,425	585,600	433,150	221,875
ENP				
Notional Volume (Bbls)	644,385	1,506,090	1,341,375	1,168,000
Consolidated				
Notional Volume (Bbls)	936,810	2,091,690	1,774,525	1,389,875

(1) On July 7, 2011, we sold $120 calls on 125 Bbl/day for 2012-2013, establishing a Three-Way Collar.

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
Gas Positions:				
Swaptions:				
VNG				
Notional Volume (MMBtu)	—	—	1,277,500	—
Weighted Average Fixed Price ($/MMBtu)	$ —	$ —	$ 5.77	$ —
ENP				
Notional Volume (MMBtu)	—	—	365,000	—
Weighted Average Fixed Price ($/MMBtu)	$ —	$ —	$ 5.40	$ —
Consolidated				
Notional Volume (MMBtu)	—	—	1,642,500	—
Weighted Average Fixed Price ($/MMBtu)	$ —	$ —	$ 5.69	$ —
Oil Positions:				
Swaptions:				
VNG				
Notional Volume (Bbls)	91,500	68,600	127,750	292,000
Weighted Average Fixed Price ($/Bbl)	$ 95.20	$ 99.44	$ 95.00	$ 95.63
ENP				
Notional Volume (Bbls)	—	36,500	—	—
Weighted Average Fixed Price ($/Bbl)	$ —	$ 105.00	$ —	$ —
Consolidated				
Notional Volume (Bbls)	91,500	105,100	127,750	292,000
Weighted Average Fixed Price ($/Bbl)	$ 95.20	$ 101.37	$ 95.00	$ 95.63

Interest Rate Risks

At June 30, 2011, we had debt outstanding of $590.0 million. The amount outstanding under our reserve-based credit facility at June 30, 2011 of $185.0 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 nine thousand dollar 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 June 30, 2011 of $175.0 million. At June 30, 2011, we had outstanding borrowings under ENP's Credit Agreement of $230.0 million, $50.0 million of which has a fixed interest rate pursuant to an interest rate swap through March 2012 and the remainder of which 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 $0.03 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, VNR 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.

The following summarizes information concerning our positions in open interest rate derivative contracts at June 30, 2011 (in thousands):

Period:	Notional Amount	Fixed Libor Rates
VNG		
July 1, 2011 to January 31, 2013	$ 20,000	2.38%
July 1, 2011 to December 10, 2014	$ 20,000	2.60%
July 1, 2011 to January 31, 2015	$ 40,000	1.75%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
ENP		
July 1, 2011 to March 7, 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 June 30, 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 Liabilities	Total Amount Due From/(Owed To) Counterparty at June 30, 2011
Citibank, N.A. (A+)	$ 2,395	$ —	$ (516)	$ 1,879
Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA)	—	(4,881)	(9,852)	(14,733)
BNP Paribas (AA)	2,436	(2,728)	(16,908)	(17,200)
The Bank of Nova Scotia (AA-)	307	—	(8,003)	(7,696)
BBVA Compass (A)	—	(97)	(900)	(997)
Credit Agricole (A+)	171	(3,410)	(10,557)	(13,796)
Royal Bank of Canada (AA-)	632	—	(8,570)	(7,938)
Natixis S.A. (A+)	205	—	(378)	(173)
Bank of America (A+)	—	(819)	—	(819)
Total	$ 6,146	$ (11,935)	$ (55,684)	$ (61,473)

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 June 30, 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 June 30, 2011. Pursuant to this acquisition, the functions of the ENP 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 continuing to implement new processes and modify 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.

Additionally, the following pending litigation is outstanding related to the proposed merger with ENP. On March 29, 2011, John O'Neal, a purported unitholder of ENP filed a class action complaint in the 125th Judicial District of Harris County, Texas on behalf of unitholders of ENP. Similar actions were filed on April 4, 2011 by Jerry P. Morgan and on April 5, 2011 by Herbert F. Rower in other Harris County district courts. The *O'Neal, Morgan, and Rower* actions were consolidated on June 5, 2011 as *John O'Neal v. Encore Energy Partners, L.P., et al*., Case Number 2011-19340, which is pending in the 125th Judicial District Court of Harris County. On July 13, 2011, plaintiffs in the consolidated *O'Neal* action filed an amended putative class action complaint alleging breaches of fiduciary duty and aiding and abetting breach of fiduciary duty claims against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, VNG, Vanguard Acquisition Company, LLC, and Vanguard. Plaintiffs seek an injunction prohibiting the proposed merger from going forward and compensatory damages if the proposed merger is consummated. The defendants named in the Texas lawsuits intend to defend vigorously against them.

On April 5, 2011, Stephen Bushansky, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption *In re: Encore Energy Partners LP Unitholder Litigation,* C.A. No. 6347-VCP. On June 21, 2011, those plaintiffs jointly filed a consolidated class action complaint naming as defendants ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, and Vanguard. That putative class action complaint alleges, among other things, that defendants breached contractual duties owed to ENP's unitholders under the applicable partnership agreement by proposing and recommending the proposed merger. Plaintiffs seek an injunction prohibiting the proposed merger from going forward and compensatory damages if the proposed merger is consummated. In response, Vanguard has filed a motion to dismiss and it intends to defend vigorously against this lawsuit.

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

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.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the Safe Drinking Water Act's (the "SDWA") Underground Injection Control Program and has begun the process of drafting guidance documents on regulating requirements for companies that plan to conduct hydraulic fracturing using diesel fuel. A number of federal agencies are analyzing a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with initial results expected to be available by late 2012 and final results by 2014. In addition, U.S. Department of Energy ("DOE") and the U.S. Government Accountability Office have undertaken studies related to hydraulic fracturing operations, and the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. A committee of the United States House of Representatives also has conducted an investigation of hydraulic fracturing practices. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including the states in which we operate. For example, on June 17, 2011, Texas signed into law a bill that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulations oil and natural gas production) and the public. The disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently Proposed Rules Regulating Air Emissions from Oil and Gas Operations Could Cause Us to Incur Increased Capital Expenditures and Operating Costs.

On July 28, 2011, the Environmental Protection Agency ("EPA") proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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)
10.1	Purchase and Sale Agreement, dated June 22, 2011 among Vanguard Permian, LLC and Encore Energy Partners Operating, LLC and EnerVest Institutional Fund X-A, L.P. and EnerVest Institutional Fund X-WI, L.P.	Form 8-K, filed June 23, 2011 (File No. 001-33756)
10.2	Purchase and Sale Agreement, dated June 22, 2011 among Vanguard Permian, LLC and Encore Energy Partners Operating, LLC and EV Properties, L.P.	Form 8-K, filed June 23, 2011 (File No. 001-33756)
10.3	Agreement and Plan of Merger, dated July 10, 2011 among Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Vanguard Acquisition Company, LLC, Encore Energy Partners L.P. and Encore Energy Partners GP LLC	Form 8-K, filed July 11, 2011 (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

SIGNATURES

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

VANGUARD NATURAL RESOURCES, LLC
(Registrant)

Date: August 9, 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 Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: August 9, 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 Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: August 9, 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 Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended June 30, 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; 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)

August 9, 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 Quarterly Report of Vanguard Natural Resources, LLC (the “Company”) on Form 10-Q for the period ended June 30, 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; 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)

August 9, 2011