Supplemental Q3 2015 Earnings Results

VANGUARD NATURAL RESOURCES, LLC
NASDAQ: VNR

THE MONTHLY DISTRIBUTION MLP™

Third Quarter 2015 Highlights

- Adjusted EBITDA (a non-GAAP financial measure defined at the end of this presentation) decreased 19% to $88.2 million in the third quarter of 2015 from $108.2 million in the third quarter of 2014 and decreased 3% from the $90.6 million recorded in the second quarter of 2015.

- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined at the end of this presentation) decreased 41% to $31.3 million from the $53.0 million generated in the third quarter of 2014 and decreased 12% from the $35.5 million generated in the second quarter of 2015.

- Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure defined at the end of this presentation) was $1.6 million in the third quarter of 2015, or $0.02 per basic unit, as compared to Adjusted Net Income of $27.9 million, or $0.34 per basic unit, in the third quarter of 2014 and Adjusted Net Loss of $6.6 million, or $0.07 per basic unit, in the second quarter of 2015. The third quarter of 2015 includes net non-cash losses of $470.6 million that are adjustments to arrive at Adjusted Net Income Attributable to Common and Class B Unitholders. The third quarter 2015 adjustments include a $491.5 million impairment charge on our oil and natural gas properties. The third quarter of 2014 results included net non-cash gains of $81.6 million primarily attributable to the change in fair value of commodity derivative contracts.

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Selected Summary Financials

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	($ in thousands, except per unit data) (Unaudited)			
Production (Mcfe/d)	386,679	321,847	383,067	301,816
Oil, natural gas and natural gas liquids sales	$ 90,827	$ 153,627	$ 285,562	$ 467,886
Net gains (losses) on commodity derivative contracts	$ 64,328	$ 83,311	$ 102,561	$ (11,125)
Operating expenses	$ 43,251	$ 46,141	$ 132,509	$ 142,419
Selling, general and administrative expenses	$ 8,046	$ 7,140	$ 26,239	$ 23,042
Depreciation, depletion, amortization, and accretion	$ 52,428	$ 55,680	$ 182,443	$ 150,798
Impairment of oil and natural gas properties	$ 491,487	$ —	$ 1,357,462	$ —
Net income (loss) attributable to Common and Class B unitholders	$ (468,967)	$ 109,150	$ (1,394,822)	$ 112,975
Adjusted Net Income Attributable to Common and Class B Unitholders (1)	$ 1,606	$ 27,916	$ 12,995	$ 74,483
Adjusted Net Income Attributable to Common and Class B Unitholders, per unit (1)	$ 0.02	$ 0.34	$ 0.15	$ 0.92
Adjusted EBITDA (1)	$ 88,204	$ 108,245	$ 264,122	$ 295,796
Interest expense, including settlements paid on interest rate derivative contracts	$ 22,118	$ 17,742	$ 64,661	$ 52,555
Estimated maintenance capital expenditures	$ 28,113	$ 32,566	$ 80,213	$ 92,716
Distributions to Preferred unitholders	$ 6,690	$ 4,949	$ 20,070	$ 11,507
Distributable Cash Flow Available to Common and Class B Unitholders (1)	$ 31,283	$ 52,988	$ 99,178	$ 140,968
Distributable Cash Flow per common and Class B unit (1)	$ 0.36	$ 0.63	$ 1.15	$ 1.73
Common and Class B unit distribution coverage (1)	1.02x	1.00x	1.09x	0.91x
Weighted average common and Class B units outstanding at record date attributable to distribution period	87,018	83,768	86,009	81,663

(1) Non-GAAP financial measures. Please see Adjusted Net Income Attributable to Common and Class B Unitholders, Adjusted EBITDA and Distributable Cash Flow Available to Common and Class B Unitholders tables at the end of this presentation for a reconciliation of these measures to their nearest comparable GAAP measure.

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Commodity Hedge Summary (as of 10/1/15)

Percent Production Hedged – VNR Stand Alone

	October 1 - December 31, 2015	Year 2016	Year 2017
Gas Production Hedged:			
% Anticipated Production Hedged	88%	68%	41%
Weighted Average Price ($/MMBtu)	$ 4.26	$ 4.37	$ 4.18
Oil Production Hedged:			
% Anticipated Production Hedged	79%	50%	—%
Weighted Average Price ($/Bbl)	$ 72.27	$ 81.14	$ —
NGLs Production Hedged:			
% Anticipated Production Hedged	9%	21%	—%
Weighted Average Price ($/Bbl)	$ 46.34	$ 29.96	$ —

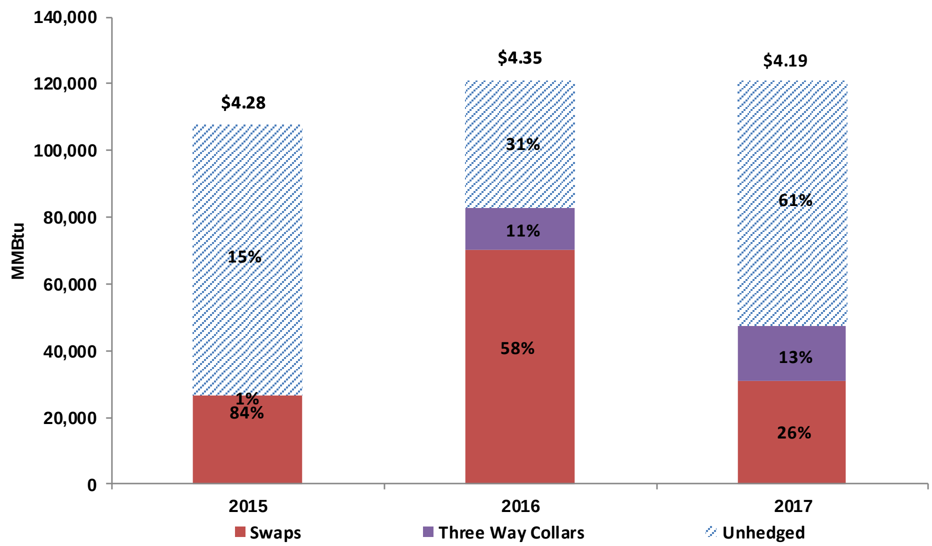
Percent Production Hedged – Pro Forma

	October 1 - December 31, 2015	Year 2016	Year 2017
Gas Production Hedged:			
% Anticipated Production Hedged	85%	69%	39%
Weighted Average Price ($/MMBtu)	$ 4.31	$ 4.35	$ 4.19
Oil Production Hedged:			
% Anticipated Production Hedged	78%	59%	17%
Weighted Average Price ($/Bbl)	$ 79.64	$ 83.27	$ 86.71
NGLs Production Hedged:			
% Anticipated Production Hedged	24%	21%	—%
Weighted Average Price ($/Bbl)	$ 34.13	$ 30.31	$ —

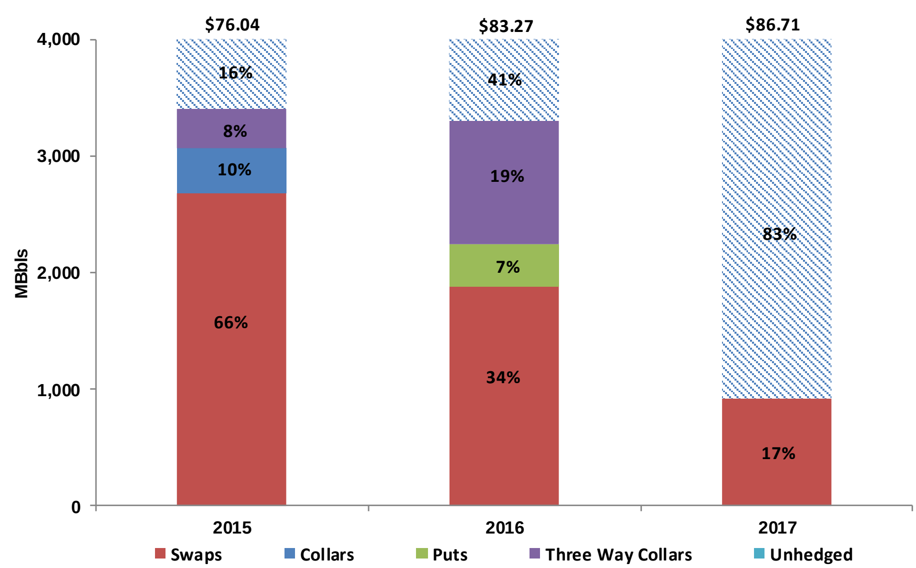
Note: Hedge prices reflect a weighted average of swap prices, long put prices and long put prices on three way collars.

Commodity Hedge Summary (as of 10/1/15)

Natural Gas Hedges (Full Year)



Oil Hedges (Full Year)



Note: Hedge prices reflect a weighted average of swap prices, long put prices and long put prices on three way collars. The impact of the pending mergers with LRE and EROC are included in the amounts and percentages shown.

Natural Gas Hedge Positions (Q4 2015 - 2017)

	Oct 1- Dec 31, 2015	Year 2016	Year 2017
Gas Positions:			
Fixed Price Swaps			
Notional Volume (MMBtu)	26,465,699	69,996,888	31,112,760
Fixed Price ($/MMBtu)	$4.31	$4.43	$4.33
Three Way Collars			
Notional Volume (MMBtu)	-	12,810,000	16,425,000
Floor Price ($/MMBtu)	-	$3.95	$3.92
Ceiling Price ($/MMBtu)	-	$4.25	$4.23
Put Sold Price ($/MMBtu)	-	$3.00	$3.37
Total			
Notional Volume (MMBtu)	26,465,699	82,806,888	47,537,760
Floor Price ($/MMBtu)	$4.31	$4.35	$4.19
Basis Swaps			
Northwest Rockies Pipeline - NYMEX			
Notional Volume (MMBtu)	7,360,000	23,790,000	10,950,000
Fixed Price ($/MMBtu)	($0.28)	($0.23)	($0.22)
WAHA - NYMEX			
Notional Volume (MMBtu)	422,138	1,608,814	-
Fixed Price ($/MMBtu)	($0.14)	($0.13)	-
HSC - NYMEX			
Notional Volume (MMBtu)	263,727	982,206	-
Fixed Price ($/MMBtu)	($0.10)	($0.08)	-
CEGT - NYMEX			
Notional Volume (MMBtu)	525,460	-	-
Fixed Price ($/MMBtu)	($0.23)	-	-
TexOk - NYMEX			
Notional Volume (MMBtu)	74,953	286,027	-
Fixed Price ($/MMBtu)	($0.13)	($0.10)	-
Calls Sold			
Notional Volume (MMBtu)	-	9,150,000	9,125,000
Fixed Price ($/MMBtu)	-	$4.25	$4.50
Puts Sold			
Notional Volume (MMBtu)	6,670,000	1,830,000	1,825,000
Fixed Price ($/MMBtu)	$3.16	$3.00	$3.50
Range Bonus Accumulators			
Notional Volume (MMBtu)	368,000	-	-
Bonus ($/MMBtu)	$0.16	-	-
Range Ceiling ($/MMBtu)	$4.00	-	-
Range Floor ($/MMBtu)	$2.50	-	-

Note: Hedge positions updated as of November 5, 2015. The impact of the pending mergers with LRE and EROC are included in the amounts and percentages shown.

Oil Hedge Positions (Q4 2015 - 2017)

	Oct 1- Dec 31, 2015	Year 2016	Year 2017
Oil Positions:			
NYMEX Fixed Price Swaps			
Notional Volume (Bbls)	936,730	1,875,531	749,698
Fixed Price ($/Bbl)	$79.00	$84.01	$85.70
LLS Fixed Price Swaps			
Notional Volume (Bbls)	-	-	168,000
Fixed Price ($/Bbl)	-	-	$91.25
Collars			
Notional Volume (Bbl)	166,000	-	-
Floor Price ($/Bbl)	$78.92	-	-
Ceiling Price ($/Bbl)	$86.72	-	-
Puts			
Notional Volume (Bbls)	-	366,000	-
Put ($/Bbl)	-	$60.00	-
Three Way Collars			
Notional Volume (Bbl)	69,000	1,061,400	-
Floor Price ($/Bbl)	$90.00	$90.00	-
Ceiling Price ($/Bbl)	$99.13	$96.18	-
Put Sold ($/Bbl)	$76.67	$73.62	-
Total			
Notional Volume (Bbls)	1,171,730	3,302,931	917,698
Floor Price ($/Bbl)	$79.64	$83.27	$86.71
Basis Swaps			
Midland-Cushing			
Notional Volume (Bbls)	220,005	968,700	-
Fixed Price ($/Bbl)	($2.33)	($1.01)	-
Cushing-WTS			
Notional Volume (Bbls)	36,800	219,600	-
Fixed Price ($/Bbl)	($2.33)	($0.43)	-
WTI-WCS			
Notional Volume (Bbls)	184,000	-	-
Fixed Price ($/Bbl)	($14.50)	-	-
Call Spreads			
Notional Volume (Bbls)	473,800	-	-
Call Price ($/Bbl)	$70.00	-	-
Short Call Price ($/Bbl)	$85.00	-	-
Calls Sold			
Notional Volume (Bbls)	18,400	622,200	365,000
Fixed Price ($/Bbl)	$105.00	$125.00	$95.00
Range Bonus Accumulators			
Notional Volume (Bbl)	46,000	183,000	-
Bonus ($/Bbl)	$4.00	$4.00	-
Range Ceiling ($/Bbl)	$100.00	$100.00	-
Range Floor ($/Bbl)	$75.00	$75.00	-
Puts Sold			
Notional Volume (Bbls)	128,800	146,400	73,000
Put Sold ($/Bbl)	$71.43	$75.00	$75.00

Note: Hedge positions updated as of November 5, 2015. The impact of the pending mergers with LRE and EROC are included in the amounts and percentages shown.

NGL Hedge Positions (Q4 2015 - 2017)

	Oct 1- Dec 31, 2015	Year 2016	Year 2017
Natural Gas Liquids:			
Fixed Price Swaps			
Mont Belviu Ethane			
Notional Volume (Bbls)	15,491	-	-
Fixed Price ($/Bbl)	$11.35	-	-
Mont Belviu Propane			
Notional Volume (Bbls)	135,823	455,700	-
Fixed Price ($/Bbl)	$31.33	$23.62	-
Mont Belviu N. Butane			
Notional Volume (Bbls)	46,604	201,300	-
Fixed Price ($/Bbl)	$35.00	$28.54	-
Mont Belviu Isobutane			
Notional Volume (Bbls)	31,663	95,700	-
Fixed Price ($/Bbl)	$38.94	$28.54	-
Mont Belviu N. Gasoline			
Notional Volume (Bbls)	25,494	154,200	-
Fixed Price ($/Bbl)	$55.15	$53.50	-
NGL Composite Hedge			
Notional Volume (Bbls)	20,460	-	-
Fixed Price ($/Bbl)	$34.38	-	-
Total			
Notional Volume (Bbls)	275,535	906,900	-
Fixed Price ($/Bbl)	$34.13	$30.31	-

Note: Hedge positions updated as of November 5, 2015. The impact of the pending mergers with LRE and EROC are included in the amounts and percentages shown.

Adjusted EBITDA

Adjusted EBITDA

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

Adjusted EBITDA is not intended to represent cash flows for the period, nor is it presented as a substitute for net income (loss), operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income (loss) and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies. For example, we fund premiums paid for derivative contracts, acquisitions of oil and natural gas properties, including the assumption of derivative contracts related to these acquisitions, and other capital expenditures primarily with proceeds from debt or equity offerings or with borrowings under our Reserve-Based Credit Facility. For the purposes of calculating Adjusted EBITDA, we consider the cost of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investments related to our underlying oil and natural gas properties; therefore, they are not deducted in arriving at our Adjusted EBITDA. Our Consolidated Statements of Cash Flows, prepared in accordance with GAAP, present cash settlements on matured derivatives and the initial cash outflows of premiums paid to enter into derivative contracts as operating activities. When we assume derivative contracts as part of a business combination, we allocate a part of the purchase price and assign them a fair value at the closing date of the acquisition. The fair value of the derivative contracts acquired is recorded as a derivative asset or liability and presented as cash used in investing activities in our Consolidated Statements of Cash Flows. As the volumes associated with these derivative contracts, whether we entered into them or we assumed them, are settled, the fair value is recognized in operating cash flows. Whether these cash settlements on derivatives are received or paid, they are reported as operating cash flows which may increase or decrease the amount we have available to fund distributions.

As noted above, for purposes of calculating Adjusted EBITDA, we consider both premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities. This is similar to the way the initial acquisition or development costs of our oil and natural gas properties are presented in our Consolidated Statements of Cash Flows; the initial cash outflows are presented as cash used in investing activities, while the cash flows generated from these assets are included in operating cash flows. The consideration of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities for purposes of determining our Adjusted EBITDA differs from the presentation in our consolidated financial statements prepared in accordance with GAAP which (i) presents premiums paid for derivatives entered into as operating activities and (ii) the fair value of derivative contracts acquired as part of a business combination as investing activities.

Distributable Cash Flow

Distributable Cash Flow Available to Common and Class B Unitholders

Distributable Cash Flow Available to Common and Class B Unitholders is used by management as a tool to measure (prior to the establishment of any cash reserves by our board of directors) the cash distributions we could pay our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our monthly distribution rates. However, Distributable Cash Flow Available to Common and Class B Unitholders should not be viewed as indicative of the amount that we plan to distribute for a given period. Distributable Cash Flow Available to Common and Class B Unitholders is not intended to be a substitute for net income (loss), operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Distributable Cash Flow Available to Common and Class B Unitholders is a metric commonly used by investors and the analyst community to assess our financial performance from period to period.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital or other borrowings, and not solely on our GAAP net income (loss), which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may be able to pay distributions during periods when we incur net losses. Our board of directors determines the appropriate level of distributions on a periodic basis in accordance with the provisions of our limited liability company agreement. Management considers the timing and size of capital expenditures and long-term views about expected results in determining the amount of distributions. Capital spending and the resulting production and net cash provided by operating activities do not typically occur evenly throughout the year due to a variety of factors which are difficult to predict, including rig availability, weather, well performance, the timing of completions and the commodity price environment. Consistent with practices common to publicly traded partnerships, our board of directors historically has not varied the distribution it declares period to period based on uneven available distributable cash flow. Our board of directors reviews historical financial results and forecasts for future periods, including development activities, as well as considers the impact of significant acquisitions in making a determination to increase, decrease or maintain the current level of distribution. In instances following acquisitions and development activities, our board of directors reviews any excess in distributable cash flows after distributions to unitholders in those periods, as well as forecasts of expected future net cash flows to determine if increases in distributions could be made. If shortfalls are sustained over time and forecasts demonstrate expectations for continued future shortfalls, our board of directors may determine to reduce, suspend or discontinue paying distributions. Our board of directors may decide to retain the excess in distributable cash flows after distributions to unitholders for our future operations, future capital expenditures, future debt service or other future obligations. Any shortfalls are funded with cash on hand and/or with borrowings under our reserve-based credit facility.

Adjusted Net Income

Adjusted Net Income Available to Common and Class B Unitholders

This information is provided because management believes exclusion of the impact of these items will help investors compare results between periods and identify operating trends that could otherwise be masked by these items and to highlight the significant fluctuations that commodity price volatility has on our results, particularly as it relates to changes in the fair value of our derivative contracts. Adjusted Net Income (Loss) Attributable to Common and Class B Unitholders is not intended to represent cash flows for the period, nor is it presented as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP.

Adjusted EBITDA and Distributable Cash Flow (a)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$ (462,277)	$ 114,099	$ (1,374,752)	$ 124,482
Plus:				
Interest expense	21,130	16,721	61,693	49,529
Depreciation, depletion, amortization, and accretion	52,428	55,680	182,443	150,798
Impairment of oil and natural gas properties	491,487	—	1,357,462	—
Net (gains) losses on commodity derivative contracts	(64,328)	(83,311)	(102,561)	11,125
Net cash settlements received (paid) on matured commodity derivative contracts [(a)(b)(c)]	45,368	6,033	125,988	(13,347)
Net (gains) losses on interest rate derivative contracts[(d)]	807	(511)	2,291	1,068
Net (gains) losses on acquisitions of oil and natural gas properties	284	(2,409)	284	(34,523)
Texas margin taxes	(522)	156	(380)	(125)
Compensation related items	3,827	1,438	11,654	6,440
Material transaction costs incurred on acquisitions	—	349	—	349
Adjusted EBITDA	$ 88,204	$ 108,245	$ 264,122	$ 295,796
Less:				
Interest expense, including settlements paid on interest rate derivatives	(22,118)	(17,742)	(64,661)	(52,555)
Estimated maintenance capital expenditures[(f)]	(28,113)	(32,566)	(80,213)	(92,716)
Distributions to Preferred unitholders	(6,690)	(4,949)	(20,070)	(11,507)
Proceeds from sale of leasehold interests	—	—	—	1,950
Distributable Cash Flow Available to Common and Class B Unitholders	**$ 31,283**	**$ 52,988**	**$ 99,178**	**$ 140,968**
Distributions to Common and Class B unitholders	30,674	52,774	90,955	154,139
Excess (shortfall) of distributable cash flow after distributions to unitholders	**$ 609**	**$ 214**	**$ 8,223**	**$ (13,171)**
Distributable Cash Flow per Common and Class B unit	$ 0.36	$ 0.63	$ 1.15	$ 1.73
Common and Class B unit Distribution Coverage	1.02x	1.00x	1.09x	0.91x

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

(b) Excludes premiums paid, whether at inception or deferred, for derivative contracts that settled during theperiod. We consider the cost of premiums paid for derivatives as an investment related to our underlying oil and natural gas properties.	$ 2,057	$ —	$ 4,624	$ —
(c) Excludes the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. We consider the amounts paid to sellers for derivative contracts assumed with business combinations a part of the purchase price of the underlying oil and natural gas properties. Also excludes the fair value of derivative contracts acquired and settled during the period	$ 12,453	$ 5,608	$ 32,734	$ 16,472
(d) Excludes fair value of restructured derivative contracts.	$ —	$ —	$ (31,945)	$ —
(e) Includes settlements paid on interest rate derivatives.	$ 988	$ 1,021	$ 2,968	$ 3,026

(f) Estimated maintenance capital expenditures are intended to represent the amount of capital required to offset the decrease in production from the prior year due to the decline in proved developed producing production. These costs, which are incorporated in our annual capital budget as approved by the board of directors, include development drilling, recompletions, workovers and various other procedures to generate new or improve existing production from both operated and non-operated properties. Actual production decline rates and capital efficiency may materially differ from our projections and such estimated maintenance capital expenditures may not maintain our production. Further, because estimated maintenance capital expenditures are not intended to target specific levels of reserves, if we do not acquire new proved or unproved reserves, our total reserves will decrease over time and we would be unable to sustain production at current levels, which could adversely affect our ability to pay a distribution at the current level or at all.

Adjusted Net Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income (Loss) Attributable to Common and Class B Unitholders	$ (468,967)	$ 109,150	$ (1,394,822)	$ 112,975
Plus (less):				
Change in fair value of commodity derivative contracts	(33,470)	(82,886)	18,014	(18,694)
Change in fair value of interest ratederivative contracts	(181)	(1,532)	(677)	(1,958)
Unrealized fair value of phantom units granted to officers	—	(364)	—	(138)
Fair value of derivative contracts acquired that apply to contracts settled during the period	12,453	5,608	32,734	16,472
Net gains (losses) on acquisitions of oil and natural gas properties	284	(2,409)	284	(34,523)
Impairment of oil and natural gas properties	491,487	—	1,357,462	—
Material transaction costs incurred on acquisitions	—	349	—	349
Adjusted Net Income Attributable to Common and Class B Unitholders	$ 1,606	$ 27,916	$ 12,995	$ 74,483
Net Income (Loss) Attributable to Common and Class B Unitholders, per unit	$ (5.39)	$ 1.31	$ (16.25)	$ 1.39
Plus (less):				
Change in fair value of commodity derivative contracts	(0.38)	(0.99)	0.21	(0.23)
Change in fair value of interest rate derivative contracts	—	(0.02)	(0.01)	(0.02)
Unrealized fair value on phantom units granted to officers	—	—	—	—
Fair value of derivative contracts acquired that apply to contracts settled during the period	0.14	0.07	0.38	0.20
Net gains (losses) on acquisitions of oil and natural gas properties	—	(0.03)	—	(0.42)
Impairment of oil and natural gas properties	5.65	—	15.82	—
Adjusted Net Income Attributable to Common and Class B Unitholders, per unit	$ 0.02	$ 0.34	$ 0.15	$ 0.92
Weighted average common and Class B units outstanding	87,012	83,525	85,834	81,377

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Coverage Ratio Calculation

Distribution Coverage Ratio

The coverage ratio is used to determine the amount of actual cash distributions the company makes, relative to the amount it could potentially pay out. The amount of distribution which could be paid out is referred to as Distributable Cash Flow. The coverage ratio is then calculated by dividing Distributable Cash Flow by the actual cash distribution.

	Three Months Ended		
	3/31/15	**6/30/15**	**9/30/15**
Adjusted EBITDA	$85,339	$90,579	$88,204
Interest expense, net	(21,179)	(21,364)	(22,118)
Maintenance capital expenditures	(25,069)	(27,031)	(28,113)
Distributions to preferred unitholders	(6,690)	(6,690)	(6,690)
Distributable cash flow	$32,401	$35,494	$31,283
Distributable cash flow per unit	$0.38	$0.41	$0.36
Distribution per unit	$0.3525	$0.3525	$0.3525
Units outstanding (millions)	84.5	86.5	87.0
Distribution coverage ratio	1.09x	1.16x	1.02x

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Production and Realized Pricing

	Three Months Ended September 30, 2015 [(a)]	Three Months Ended September 30, 2014 [(a)]	Percentage Increase / (Decrease)	Three Months Ended June 30, 2015	Percentage Increase / (Decrease)
Total production volumes:					
Oil (MBbls)	839	813	3 %	866	(3)%
Natural Gas (MMcf)	26,242	20,962	25 %	23,543	11 %
NGLs (MBbls)	717	629	14 %	796	(10)%
Combined (MMcfe)	35,574	29,610	20 %	33,514	6 %
Average daily production volumes:					
Oil (Bbls/day)	9,115	8,832	3 %	9,511	(3)%
Natural Gas (Mcf/day)	285,236	227,850	25 %	258,720	11 %
NGLs (Bbls/day)	7,792	6,835	14 %	8,751	(10)%
Combined (Mcfe/day)	386,679	321,847	20 %	368,290	6 %
Average NYMEX prices:					
Oil (Price/Bbl)	$ 46.39	$ 97.13	(52)%	$ 57.94	(20)%
Natural Gas (Price/Mcf)	$ 2.77	$ 4.07	(32)%	$ 2.63	5 %
Average realized prices, excluding hedges:					
Oil (Price/Bbl)	$ 40.10	$ 84.96	(53)%	$ 50.85	(21)%
Natural Gas (Price/Mcf)	$ 1.94	$ 3.24	(40)%	$ 1.69	15 %
NGLs (Price/Bbl)	$ 8.86	$ 26.66	(67)%	$ 14.98	(41)%
Average realized prices, including hedges[(b)]:					
Oil (Price/Bbl)	$ 53.66	$ 84.36	(36)%	$ 58.02	(8)%
Natural Gas (Price/Mcf)	$ 3.17	$ 3.55	(11)%	$ 3.16	— %
NGLs (Price/Bbl)	$ 11.23	$ 26.70	(58)%	$ 16.93	(34)%

(a) During 2015 and 2014, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included from the closing date of the acquisition forward.

(b) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

Statements of Operations (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$ 33,624	$ 69,034	$ 113,425	$ 211,197
Natural gas sales	50,851	67,827	146,502	201,175
NGLs sales	6,352	16,766	25,635	55,514
Net gains (losses) on commodity derivative contracts	64,328	83,311	102,561	(11,125)
Total revenues	155,155	236,938	388,123	456,761
Costs and expenses:				
Production:				
Lease operating expenses	34,169	31,011	101,247	95,726
Production and other taxes	9,082	15,130	31,262	46,693
Depreciation, depletion, amortization, and accretion	52,428	55,680	182,443	150,798
Impairment of oil and natural gas properties	491,487	—	1,357,462	—
Selling, general and administrative expenses	8,046	7,140	26,239	23,042
Total costs and expenses	595,212	108,961	1,698,653	316,259
Income (loss) from operations	(440,057)	127,977	(1,310,530)	140,502
Other income (expense):				
Interest expense	(21,130)	(16,721)	(61,693)	(49,529)
Net gains (losses) on interest rate derivative contracts	(807)	511	(2,291)	(1,068)
Net gains (losses) on acquisitions of oil and natural gas properties	(284)	2,409	(284)	34,523
Other	1	(77)	46	54
Total other income (expense), net	(22,220)	(13,878)	(64,222)	(16,020)
Net income (loss)	$ (462,277)	$ 114,099	$ (1,374,752)	$ 124,482
Distributions to Preferred unitholders	(6,690)	(4,949)	(20,070)	(11,507)
Net income (loss) attributable to Common and Class B unitholders	$ (468,967)	$ 109,150	$ (1,394,822)	$ 112,975
Net income (loss) per Common and Class B units				
Basic	$ (5.39)	$ 1.31	$ (16.25)	$ 1.39
Diluted	$ (5.39)	$ 1.30	$ (16.25)	$ 1.38
Weighted average Common units outstanding				
Common units – basic	86,592	83,105	85,414	80,957
Common units – diluted	86,592	83,333	85,414	81,231
Class B units – basic & diluted	420	420	420	420

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Balance Sheets (Unaudited)

	September 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$ 19,490	$ —
Trade accounts receivable, net	66,200	140,017
Derivative assets	139,901	142,114
Other current assets	11,119	4,102
Total current assets	236,710	286,233
Oil and natural gas properties, at cost	4,257,859	4,140,527
Accumulated depletion, amortization and impairment	(2,695,554)	(1,164,721)
Oil and natural gas properties evaluated, net– full cost method	1,562,305	2,975,806
Other assets		
Goodwill	420,955	420,955
Derivative assets	62,890	83,583
Other assets	30,529	27,015
Total assets	$ 2,313,389	$ 3,793,592
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 17,682	$ 15,118
Affiliates	1,512	823
Accrued liabilities:		
Lease operating	13,152	19,822
Development capital	9,274	24,706
Interest	21,987	11,517
Production and other taxes	47,155	29,981
Derivative liabilities	636	3,583
Oil and natural gas revenue payable	22,192	40,117
Distributions payable	11,241	18,640
Other	20,770	14,297
Total current liabilities	165,601	178,604
Long-term debt	1,889,674	1,932,816
Derivative liabilities	473	1,380
Asset retirement obligations, net of current portion	173,898	146,676
Other long-term liabilities	730	—
Total liabilities	2,230,376	2,259,476
Commitments and contingencies (Note 7)		
Members' equity (Note 8)		
Cumulative Preferred units, 13,881,873 units issued and outstanding at September 30, 2015 and December 31, 2014	335,444	335,444
Common units, 86,597,301 units issued and outstanding at September 30, 2015 and 83,451,746 at December 31, 2014	(260,046)	1,191,057
Class B units, 420,000 issued and outstanding at September 30, 2015 and December 31, 2014	7,615	7,615
Total members' equity	83,013	1,534,116
Total liabilities and members' equity	$ 2,313,389	$ 3,793,592