DORCHESTER MINERALS LP
Form 10-Q
November 05, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
Or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

For the Quarterly Period Ended September 30, 2009	Commission file number 000-50175

DORCHESTER MINERALS, L.P.
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of Incorporation or organization)	81-0551518 (I.R.S. Employer Identification No.)

3838 Oak Lawn Avenue, Suite 300, Dallas, Texas 75219
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (214) 559-0300

None
Former name, former address and former fiscal
year, if changed since last report

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 x No o

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 o No o

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

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

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

As of November 5, 2009, 29,840,431 common units of partnership interest were outstanding.

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DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this 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), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements disc future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. In this report, the term "Partnership," as well as the terms "DMLP," "us," "our," "we," and "its" are sometimes us as abbreviated references to Dorchester Minerals, L.P. itself or Dorchester Minerals, L.P. and its related entities.

These forward-looking statements are based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and, therefore, involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements for a number of important reasons. Examples of such reasons include, but are not limited to, changes in the price or demand for oil and natural gas, changes in the operations on or development of our properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and our financial position, business strategy and other plans and objectives for future operations. These and other factors are set forth in our filings with the Securities and Exchange Commission.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest, you should be aware that the occurrence of any of the events described in this report could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline, and you could lose all or part of your investment.

PART I

ITEM 1. FINANCIAL INFORMATION

See attached financial statements on the following pages.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED BALANCE SHEETS
(In Thousands)

ASSETS	September 30, 2009 (unaudited)	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 10,012	$ 16,211
Trade and other receivables	4,674	5,053
Net profits interests receivable - related party	1,245	4,428
Prepaid expenses	20	-
Total current assets	15,951	25,692
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	327,063	291,818
Accumulated full cost depletion	(189,533)	(178,272)
Total	137,530	113,546
Leasehold improvements	512	512
Accumulated amortization	(243)	(207)
Total	269	305
Net property and leasehold improvements	137,799	113,851
Total assets	$ 153,769	$ 139,562
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,420	$ 733
Current portion of deferred rent incentive	39	39
Total current liabilities	1,459	772
Deferred rent incentive less current portion	178	208
Total liabilities	1,637	980
Commitments and contingencies		
Partnership capital:		

General partner		5,285		5,971
Unitholders		146,847		132,611
Total partnership capital		152,132		138,582
Total liabilities and partnership capital	$	153,769	$	139,562

The accompanying condensed notes are an integral part of these consolidated financial statements.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands except Earnings per Unit)
(Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Operating revenues:				
Royalties	$ 8,450	$ 18,284	$ 23,481	$ 51,659
Net profits interests	1,668	6,040	5,043	22,609
Lease bonus	531	154	620	411
Other	57	9	70	68
Total operating revenues	10,706	24,487	29,214	74,747
Costs and expenses:				
Operating, including production taxes	1,017	1,491	2,600	4,027
Depletion and amortization	4,524	3,775	11,297	11,213
General and administrative expenses	771	744	2,623	2,615
Total costs and expenses	6,312	6,010	16,520	17,855
Operating income	4,394	18,477	12,694	56,892
Other income, net	21	113	218	274
Net earnings	$ 4,415	$ 18,590	$ 12,912	$ 57,166
Allocation of net earnings:				
General partner	$ 152	$ 593	$ 436	$ 1,718
Unitholders	$ 4,263	$ 17,997	$ 12,476	$ 55,448
Net earnings per common unit (basic and diluted)	$ 0.14	$ 0.64	$ 0.43	$ 1.97
Weighted average common units outstanding	29,840	28,240	28,779	28,240

The accompanying condensed notes are an integral part of these consolidated financial statements.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)
(Unaudited)

	Nine Months Ended September 30, 2009	2008
Net cash provided by operating activities	$ 28,692	$ 67,968
Cash flows provided by (used in) investing activities:		
Adjustment related to acquisition of natural gas properties	967	-
Capital expenditures	-	(50)
Total cash flows provided by (used in) investing activities	967	(50)
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(35,858)	(54,021)
(Decrease) increase in cash and cash equivalents	(6,199)	13,897
Cash and cash equivalents at beginning of period	16,211	15,001
Cash and cash equivalents at end of period	$ 10,012	$ 28,898
Non-cash investing and financing activities:		
Value of units issued for natural gas properties acquired	$ 36,496	

The accompanying condensed notes are an integral part of these consolidated financial statements.

DORCHESTER MINERALS, L.P.
(A Delaware Limited Partnership)

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1 Basis of Presentation: Dorchester Minerals, L.P. is a publicly traded Delaware limited partnership that was formed in December 2001, and commenced operations on January 31, 2003. The consolidated financial statements include the accounts of Dorchester Minerals, L.P., Dorchester Minerals Oklahoma LP, Dorchester Minerals Oklahoma GP, Inc., Dorchester Minerals Acquisition LP, and Dorchester Minerals Acquisition GP, Inc. All significant intercompany balances and transactions have been eliminated in consolidation.

The condensed consolidated financial statements reflect all adjustments (consisting only of normal and recurring adjustments unless indicated otherwise) that are, in the opinion of management, necessary for the fair presentation of our financial position and operating results for the interim period. Interim period results are not necessarily indicative of the results for the calendar year. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information. Per-unit information is calculated by dividing the earnings or loss applicable to holders of our Partnership's common units by the weighted average number of units outstanding. The Partnership has no potentially dilutive securities and, consequently, basic and dilutive earnings or loss per unit do not differ. These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2008.

Fair Value of Financial Instruments—The carrying amount of cash and cash equivalents, trade receivables and payables approximates fair value because of the short maturity of those instruments. These estimated fair values may not be representative of actual values of the financial instruments that could have been realized as of quarter close or that will be realized in the future.

2 Contingencies: In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights sued Dorchester Hugoton, Ltd., along with several other operators in Texas County, Oklahoma regarding the use of natural gas from the wells in residences. Dorchester Minerals Operating LP, the operating partnership, now owns and operates the properties formerly owned by Dorchester Hugoton. These properties contribute a major portion of the Net Profits Interests amounts paid to us. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding such residential gas use. On October 4, 2004, the plaintiffs filed severed claims against the operating partnership regarding royalty underpayments, which the Texas County District Court subsequently dismissed with a grant of time to replead. On January 27, 2006, one of the original plaintiffs again sued the operating partnership for underpayment of royalty, seeking class action certification. On October 1, 2007, the Texas County District Court granted the operating partnership's motion for summary judgment finding no royalty underpayments. Subsequently, the District Court denied the plaintiff's motion for reconsideration, and the plaintiff filed an appeal. At present, the litigation awaits result of the appeal to the Oklahoma Supreme Court. An adverse appellate decision could reduce amounts we receive from the Net Profits Interests.

Gain - Dorchester Minerals, L.P filed Cause No. 07-0250-15; Dorchester Minerals, LP v. H&S Production, Inc. in the 15th District Court of Grayson County Texas in January, 2007. The suit involved claims under an oil and gas lease between us as lessor and H&S as lessee. Our Motion for Summary Judgment, which included damages in the amount of $496,000, was granted by the trial court in May 2008. H&S appealed the Judgment. The Fifth District Court of Appeals affirmed the Judgment on liability and remanded on damages. The subsequent Motion for Rehearing filed by H&S was denied by the Fifth District Appeals Court. The matter was settled on October 22, 2009 with the Appeals Court ruling on liability continuing to stand, the dismissal with prejudice of the remanded action on damages, and receipt of a $500,000 payment from H&S to us. The deposit will be recorded in the fourth quarter 2009 financial statements.

The Partnership and the operating partnership are involved in other legal and/or administrative proceedings arising in the ordinary course of their businesses, none of which have predictable outcomes and none of which are believed to have any significant effect on consolidated financial position, cash flows, or operating results.

3 Acquisition for Units: On June 30, 2009, we acquired producing and non-producing Barnett Shale mineral and royalty interests located in Tarrant County, Texas for 1,600,000 common units of Dorchester Minerals, L.P. issued pursuant to a shelf registration statement. Net assets acquired at the date of acquisition totaled $36,496,000. The Condensed Consolidated Balance Sheets presented include $35,245,000 in property additions. After the issuance, 3,400,000 units remain available under the shelf registration statement.

4 Distributions to Holders of Common Units: Unitholder cash distributions per common unit since 2005 have been:

	Per Unit Amount				
	2009	2008	2007	2006	2005
First quarter	$0.401205	$0.572300	$0.461146	$0.729852	$0.481242
Second quarter	$0.271354	$0.769206	$0.473745	$0.778120	$0.514542
Third quarter	$0.286968	$0.948472	$0.560502	$0.516082	$0.577287
Fourth quarter		$0.542081	$0.514625	$0.478596	$0.805543

Distributions beginning with the second quarter of 2009 were paid on 29,840,431 units; previous distributions above were paid on 28,240,431 units. The third quarter 2009 distribution was paid November 5, 2009. Fourth quarter distributions shown above are paid in the first calendar quarter of the following year. Our partnership agreement requires the next cash distribution to be paid by February 15, 2010.

5 New Accounting Pronouncements: The Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 105-10-5, General Principles, Generally Accepted Accounting Principles defines the new hierarchy for U.S. GAAP and explains how the FASB will use its Accounting Standards Codification as the sole source for all authoritative guidance. FASB ASC 105-10-5 replaces SFAS 162, The Hierarchy of Generally Accepted Accounting Principles, which was issued in May 2008. It was effective for all reporting periods ending after September 15, 2009 and we have revised all references to pre-codification GAAP in our financial statements. It did not have a material impact on our consolidated financial statements.

FASB ASC 805-10, Business Combinations, among other things, establishes principles and requirements for how the acquirer in a business combination (a) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquired business, (b) changes the accounting for contingent consideration, in process research and development, and restructuring costs, (c) expenses acquisition-related costs as incurred, (d) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (e) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. We adopted FASB ASC 805-10 as of January 1, 2009 with no material impact on our consolidated financial statements.

FASB ASC 820-10, Fair Value Measurements and Disclosures, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. It also emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Under FASB ASC 820-10, fair value measurements are disclosed by level within that hierarchy. We adopted ASC 820-10 for the fiscal year beginning January 1, 2008 with no material impact on our consolidated financial statements. We adopted the delayed portion for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis beginning January 1, 2009 with no material impact on our consolidated financial statements.

FASB ASC 825-10-65, Interim Disclosures about Fair Value of Financial Instruments requires disclosures about fair value of financial instruments for interim reporting periods and amends FASB ASC 270-10 Interim Reporting to require those disclosures in summarized financial information at interim reporting periods. It was effective for all reporting periods after June 15, 2009 and did not have a material impact on our consolidated financial statements.

FASB ASC 855-10, Subsequent Events, incorporates the accounting and disclosure requirements for subsequent events into U.S. generally accepted accounting principles. FASB ASC 855-10 introduces new terminology, defines a date through which management must evaluate subsequent events, and lists the circumstances under which an entity must recognize and disclose events or transactions occurring after the balance-sheet date. We adopted FASB ASC 855-10 as of June 30, 2009, which was the required effective date.

6 Subsequent Events: We evaluated subsequent events through November 5, 2009, which represents the date the financial statements were issued. We are not aware of any subsequent events, which are not already recognized or disclosed, that would require recognition or disclosure in the financial statements.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We own producing and nonproducing mineral, royalty, overriding royalty, net profits and leasehold interests. We refer to these interests as the Royalty Properties. We currently own Royalty Properties in 574 counties and parishes in 25 states.

Dorchester Minerals Operating LP, a Delaware limited partnership owned directly and indirectly by our general partner, holds working interest properties and a minor portion of mineral and royalty interest properties. We refer to Dorchester Minerals Operating LP as the "operating partnership" or "DMOLP." We directly and indirectly own a 96.97% net profits overriding royalty interest (referred to as Net Profits Interests, or NPIs) in property groups made up of four NPIs created when we commenced operations in 2003 and one immaterial deficit NPI subsequently created. We currently receive monthly payments equaling 96.97% of the preceding month's net profits actually realized by the operating partnership from three of the property groups. The purpose of such Net Profits Interests is to avoid the participation as a working interest or other cost-bearing owner that could result in unrelated business taxable income. Net profits interest payments are not considered unrelated business taxable income for tax purposes. One such Net Profits Interest, referred to as the Minerals NPI, has continuously had costs that exceed revenues. As of September 30, 2009, cumulative operating and development costs presented in the following table, which include amounts equivalent to an interest charge, exceeded cumulative revenues of the Minerals NPI, resulting in a cumulative deficit. All cumulative deficits (which represent cumulative excess of operating and development costs over revenue received) are borne 100% by our general partner until the Minerals NPI recovers the deficit amount. Once in profit status, we will receive the Net Profits Interest payments attributable to these properties. Our consolidated financial statements do not reflect activity attributable to properties subject to Net Profits Interests that are in a deficit status. Consequently, Net Profits Interest payments and production sales volumes and prices set forth in other portions of this quarterly report do not reflect amounts attributable to the Minerals NPI, which includes all of the operating partnership's Fayetteville Shale working interest properties in Arkansas.

The following table sets forth receipts and disbursements attributable to the Minerals NPI:

Minerals NPI Results (in Thousands)

	Cumulative Total at 12/31/08	Nine Months Ended 9/30/09	Cumulative Total at 9/30/09
Cash received for revenue	$ 14,216	$ 2,518	$ 16,734
Cash paid for operating costs	2,226	610	2,836
Cash paid for development costs	11,724	3,377	15,101
Budgeted capital expenditures	905	481	1,386
Net	$ (639)	$ (1,950)	$ (2,589)

The development costs pertain to more properties than the properties producing revenue due to timing differences between operating partnership expenditures and oil and natural gas production and payments to the operating partnership. The amounts reflect the operating partnership's ownership of the subject properties. Net Profits Interest payments to us, if any, will equal 96.97% of the cumulative net profits actually received by the operating partnership attributable to subject properties. The above financial information attributable to the Minerals NPI may not be indicative of future results of the Minerals NPI and may not indicate when the deficit status may end and when Net Profits Interest payments may begin from the Minerals NPI.

Commodity Price Risks

Our profitability is affected by volatility in prevailing oil and natural gas prices. Oil and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for oil and natural gas in the market along with domestic and international political economic conditions.

Results of Operations

Three and Nine Months Ended September 30, 2009 as compared to Three and Nine Months Ended September 30, 2008

Normally, our period-to-period changes in net earnings and cash flows from operating activities are principally determined by changes in oil and natural gas sales volumes and prices. Our portion of oil and natural gas sales and weighted average prices were:

	Three Months Ended September 30,		June 30,	Nine Months Ended September 30,	
Accrual basis sales volumes:	2009	2008	2009	2009	2008
Royalty properties gas sales (mmcf)	1,148	1,000	1,019	3,204	2,864
Royalty properties oil sales (mbbls)	71	77	80	225	229
Net profits interests gas sales (mmcf)	915	961	903	2,705	2,922
Net profits interests oil sales (mbbls)	3	2	3	9	9
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$ 3.39	$ 9.41	$ 3.47	$ 3.63	$ 9.31
Royalty properties oil sales ($/bbl)	$ 63.94	$ 115.62	$ 55.90	$ 52.74	$ 109.33
Net profits interests gas sales ($/mcf)	$ 3.04	$ 7.76	$ 2.95	$ 3.10	$ 9.23
Net profits interests oil sales ($/bbl)	$ 58.76	N/A	$ 55.70	$ 47.27	$ 118.47
Accrual basis production costs deducted					
Under the net profits interests ($/mcfe) (1)	$ 1.45	$ 1.90	$ 1.41	$ 1.44	$ 1.94

(1) Provided to assist in determination of revenues; applies only to Net Profits Interest sales volumes and prices.

Oil sales volumes attributable to our Royalty Properties during the third quarter were down 7.8% from 77 mbbls during the third quarter of 2008 to 71 mbbls in the same period of 2009 due to normal production volume variations. Oil sales volumes attributable to our Royalty Properties during the first nine months were down slightly at 225 mbbls in 2009 compared to 229 mbbls in 2008. Natural gas sales volumes attributable to our Royalty Properties during the third quarter increased 14.8% from 1,000 mmcf in 2008 to 1,148 mmcf in 2009. Natural gas sales volumes attributable to our Royalty Properties during the first nine months increased 11.9% from 2,864 in 2008 to 3,204 mmcf in 2009. The increase in natural gas sales volumes was primarily attributable to the acquisition of properties in the Barnett Shale during the second quarter of 2009.

Oil sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2009 were virtually unchanged when compared to the same periods of 2008. Natural gas sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2009 decreased from the same periods of 2008. Third quarter sales volumes of 915 mmcf during 2009 were 4.8% less than 961 mmcf during 2008. First nine month sales volumes of 2,705 mmcf during 2009 were 7.4% less than 2,922 mmcf during 2008. Both natural gas sales volume decreases were a result of natural reservoir decline. Production sales volumes and prices from the Minerals NPI are excluded from the above table. See “Overview” above.

The weighted average oil sales prices attributable to our interest in Royalty Properties decreased 44.7% from $115.62/bbl during the third quarter of 2008 to $63.94/bbl during the third quarter of 2009 and decreased 51.8% from $109.33/bbl during the first nine months of 2008 to $52.74/bbl during the same period of 2009. Third quarter weighted average natural gas sales prices from Royalty Properties decreased 64.0% from $9.41/mcf during 2008 to $3.39/mcf during 2009. The nine months ended September 30 weighted average Royalty Properties natural gas sales prices decreased 61.0% from $9.31/mcf during 2008 to $3.63/mcf during 2009. Both oil and natural gas price changes resulted from changing market conditions.

Third quarter weighted average oil sales prices from the Net Profits Interests properties decreased significantly from 2008 to $58.76/bbl in 2009. The third quarter of 2008 included a purchaser correction that significantly distorted the price due to small volumes; thus, we have not shown an average price in order to avoid confusion. The first nine months Net Profits Interests’ oil sales prices decreased 60.1% from $118.47/bbl in 2008 to $47.27/bbl in 2009. Changing market conditions resulted in decreased oil prices. Weighted average natural gas sales prices attributable to the Net Profits Interests decreased during the third quarter of 2009 and first nine months of 2009 compared to the same periods of 2008. Third quarter natural gas sales prices of $3.04/mcf in 2009 were 60.8% less than $7.76/mcf in 2008. The nine months ended September 30, 2009 natural gas prices decreased 66.4% to $3.10/mcf from $9.23/mcf in the same period of 2008. Natural gas sales price decreases during the three- and nine- month periods resulted from changing market conditions and, to a lesser degree, a natural gas liquids payment received in 2008 that related to prior year production. The natural gas liquids payment is based on an Oklahoma Guymon-Hugoton field 1994 gas delivery agreement that is in effect through 2015. Under the terms of the agreement, when the market price of natural gas liquids increases sufficiently disproportionately to natural gas market prices, the operating partnership receives a portion of that increase in an annual payment based on calendar year data. In the event the evaluation at the end of the annual contract period shows the payment to be determinable and collectable, the revenue is accrued.

Our third quarter net operating revenues decreased 56.3% from $24,487,000 during 2008 to $10,706,000 during 2009. Net operating revenues for the first nine months of 2009 decreased 60.9% from $74,747,000 during 2008 to $29,214,000 during 2009. Both the quarterly and nine-month decrease resulted from decreased gas and oil sales prices combined with a 2007 natural gas liquid payment received during the second quarter 2008.

Costs and expenses increased 5.0% from $6,010,000 during the third quarter of 2008 to $6,312,000 during the third quarter of 2009, while nine months ended September 30 costs and expenses decreased 7.5% from $17,855,000 during 2008 to $16,520,000 during 2009. The third quarter increase primarily resulted from increased depletion related to the Barnett Shale acquisition at the end of the second quarter partially offset by decreased production tax on lower operating revenues. The decrease in the nine-month period primarily resulted from decreased production tax.

Depletion and amortization increased 19.8% during the third quarter ended September 30, 2009 and 0.7% during the nine months ended September 30, 2009 when compared to the same periods of 2008. The increases from $3,775,000 and $11,213,000 during the third quarter and nine months ended September 30, 2008, respectively, to $4,524,000 and $11,297,000 during the same periods of 2009 respectively, resulted primarily from a higher depletable base due to the June 30, 2009 acquisition of properties in the Barnett Shale.

Third quarter net earnings allocable to common units decreased 76.3% from $17,997,000 during 2008 to $4,263,000 during 2009. First nine months common unit net earnings decreased 77.5% from $55,448,000 during 2008 to $12,476,000 during 2009. Both decreases are primarily the result of decreased oil and natural gas sales prices.

Net cash provided by operating activities decreased 67.3% from $28,082,000 during the third quarter of 2008 to $9,181,000 during the third quarter of 2009 and decreased 57.8% from $67,968,000 for the first nine months during 2008 to $28,692,000 during the same period of 2009. Decreases in both periods are primarily due to decreased oil and natural gas sales prices.

In an effort to provide the reader with information concerning prices of oil and natural gas sales that correspond to our quarterly distributions, management calculates the weighted average price by dividing gross revenues received by the net volumes of the corresponding product without regard to the timing of the production to which such sales may be attributable. This "indicated price" does not necessarily reflect the contract terms for such sales and may be affected by transportation costs, location differentials, and quality and gravity adjustments. While the relationship between our cash receipts and the timing of the production of oil and natural gas may be described generally, actual cash receipts may be materially impacted by purchasers' release of suspended funds and by purchasers' prior period adjustments.

Cash receipts attributable to our Royalty Properties during the 2009 third quarter totaled approximately $7,800,000. These receipts generally reflect oil sales during June through August 2009 and natural gas sales during May through July 2009. The weighted average indicated prices for oil and natural gas sales during the 2009 third quarter attributable to the Royalty Properties were $62.52/bbl and $3.46/mcf, respectively.

Cash receipts attributable to our Net Profits Interests during the 2009 third quarter totaled approximately $1,600,000. These receipts reflect oil and natural gas sales from the properties underlying the Net Profits Interests generally during May through July 2009. The weighted average indicated prices received during the 2009 third quarter for oil and natural gas sales were $55.30/bbl and $3.07/mcf, respectively.

We received cash payments of approximately $560,000 from various sources during the third quarter of 2009 including lease bonuses attributable to 25 consummated leases and pooling elections located in five counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $1,200/acre.

We received division orders for, or otherwise identified, 71 new wells completed on our Royalty Properties and Net Profits Interests located in 38 counties and parishes in seven states during the third quarter of 2009. The operating partnership elected to participate in ten wells to be drilled on our Net Profits Interests located in three counties in Arkansas. Selected new wells and the royalty interests owned by us and the working and net revenue interests owned by the operating partnership are summarized in the tables below.

This table does not include wells drilled in the Fayetteville Shale trend as they are detailed in a subsequent discussion and table.

State	County /Parish	Operator	Well Name	DMLP NRI(2)	DMOLP WI(1)	DMOLP NRI(2)	Test Rates per day Gas, mcf	Test Rates per day Oil, bbls
ND	Dunn	Marathon Oil Co.	Borth 41-14 H	0.916%	--	--	207	451
ND	Dunn	Marathon Oil Co.	Gehrer 21-14 H	0.916%	--	--	1,640	396
OK	Garvin	Cimarex Energy Co.	Cole 1-5	1.363%	--	--	292	484
OK	Garvin	Cimarex Energy Co.	Howard D 4-17 ENT	1.563%	--	--	215	181
TX	Hidalgo	Dewbre Petroelum	E.E. Guerra 20	0.521%	--	--	7,205	--
TX	Shelby	Devon Energy Corp.	Oliver Gas Unit 4	0.360%	--	--	19,623	--
TX	Upton	Hunt Oil Co.	V.T. Amacker 105 15H	0.977%	--	--	3,191	--

(1) WI means the working interest owned by the operating partnership and subject to a Net Profits Interest.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's royalty and working interest, which is subject to a Net Profits Interest.

FAYETTEVILLE SHALE TREND OF NORTHERN ARKANSAS – We own varying undivided perpetual mineral interests totaling 23,336/11,464 gross/net acres located in Cleburne, Conway, Faulkner, Franklin, Johnson, Pope, Van Buren, and White counties, Arkansas in an area commonly referred to as the "Fayetteville Shale" trend of the Arkoma Basin. One hundred eighty-two wells have been permitted on the lands as of September 30, 2009. Wells that have been proposed to be drilled by the operator but for which permits have not yet been issued by the Arkansas Oil & Gas Commission are not reflected in this number. Available test results for new wells producing in the third quarter, along with ownership interests owned by us and interests owned by the operating partnership subject to the Minerals NPI, are summarized in the following table.

County	Operator	Well Name	DMLP NRI(2)	DMOLP WI(1)	DMOLP NRI(2)	Gas Test Rates mcf per day
Conway	Chesapeake	Collinsworth 7-16 #1-10H3	2.312%	4.553%	3.414%	4,815
Conway	SEECO	Green Bay Packaging 9-15 #3-19H	0.056%	0.000%	0.000%	4,221
Conway	SEECO	Green Bay Packaging 9-15 #4-19H	0.056%	0.000%	0.000%	4,242
Conway	SEECO	Polk 9-15 #4-30H	5.930%	5.561%	4.220%	2,434
Faulkner	Chesapeake	Glover 8-13 #1-25H	3.222%	7.185%	5.648%	1,433
Faulkner	Chesapeake	Glover 8-13 #2-25H	2.990%	4.807%	3.614%	2,439
Van Buren	Chesapeake	Collister 12-13 #2-32H	1.561%	1.274%	0.956%	228
Van Buren	Chesapeake	Collister 12-13 #3-32H	1.561%	1.274%	0.956%	469
Van Buren	Petrohawk	Green Bay 11-14 #1-20H	0.703%	0.000%	0.000%	723
Van Buren	Petrohawk	Trahan 11-14 #1-30H	0.039%	0.000%	0.000%	4,144
Van Buren	SEECO	Handy 10-12 #3-18H19	0.395%	0.944%	0.708%	4,180
Van Buren	SEECO	Handy 10-12 #4-18H	2.971%	6.344%	4.758%	2,876

Van Buren	SEECO	Handy 10-12 #5-18H	2.972%	6.347%	4.760%	3,679
Van Buren	SEECO	Handy 10-12 #6-18H	2.972%	6.347%	4.760%	3,422
Van Buren	SEECO	Howard Family Trust 10-12 #2-9H16	2.594%	4.576%	3.432%	5,184

(1) WI means the working interest owned by the operating partnership and subject to the Minerals NPI.

(2) NRI means the net revenue interest attributable to our royalty interest or to the operating partnership's royalty and working interest, which is subject to the Minerals NPI.

Set forth below are totals and a summary of permitting, drilling and completion activity through September 30, 2009 for wells in which we have a royalty interest or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	Total to date (2)	Year 2006	Year 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009
New Well Permits	180	11	35	16	21	12	21	19	20	22
Wells Spud	145	9	33	12	17	20	13	21	15	4
Wells Completed	126	5	23	10	17	12	17	13	14	14
Wells in Pay Status (1)	85	0	14	4	7	14	7	14	10	14

(1) Wells in pay status means wells for which revenue was initially received during the indicated period.
(2) Includes activity since 2004.

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled $306,000 in the third quarter from 72 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled approximately $280,000 in the third quarter from 44 wells.

BARNETT SHALE — We own producing and nonproducing mineral and royalty interests located in Tarrant County, Texas. The properties consist of varying undivided mineral and overriding royalty interests in six tracts totaling approximately 1,820 acres in what is commonly referred to as the Core Area of the Barnett Shale Trend. All of the mineral interests were leased in 2003 to a predecessor of Chesapeake Energy Corporation, the current operator of and majority working interest owner in the properties. Approximately 577 acres of the subject lands are pooled into six units totaling 1,800 acres, approximately 1,129 acres are developed on a lease basis and the remaining lands are leased but not pooled or drilled upon. As of September 30, 2009, 34 wells were drilled from 11 padsites located on or adjacent to the properties, of which 27 wells were completed for production and seven were drilled but not yet completed or connected to a pipeline. Permits to drill two additional wells on the properties had been issued by regulatory agencies.

HORIZONTAL BAKKEN, WILLISTON BASIN – We own varying undivided perpetual mineral interests totaling 70,390/7,602 gross/net acres located in Burke, Divide, Dunn, McKenzie, Mountrail and Williams Counties, North Dakota. Operators active in this area include Continental Resources, EOG Resources, Hess Corporation and Marathon Oil Company. Seventy-nine wells have been permitted on these lands as of September 30, 2009. In all cases we have elected not to lease our lands and not to pay our share of well costs thus becoming a non-consenting mineral owner. According to North Dakota law, non-consenting owners receive the average royalty rate from the date of first production and back-in for their full working interest after the operator has recovered 150% of drilling and completion costs. Once 150% payout occurs, the working interest will be owned by the operating partnership and will be subject to the Minerals NPI. Non-consenting owners are not entitled to well data other than public information available from the North Dakota Industrial Commission.

Set forth below are totals and a summary of permitting, drilling and completion activity through September 30, 2009 for wells in which we have a royalty interest or Net Profits Interest.

	Total to Date(2)	Year 2006	Year 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009
New Well Permits	82	0	16	10	17	16	14	0	6	0
Wells Spud	69	0	12	2	10	11	10	11	4	7
Wells Completed	54	0	7	5	5	11	6	12	5	1

WI Wells in Pay Status(1)	3	0	0	0	2	1	0	0	0	0

(1) Wells in pay status means wells for which revenue was initially received during the indicated period.

(2) Includes activity since 2004.

APPALACHIAN BASIN — We own varying undivided perpetual mineral interests in approximately 31,000/22,000 gross/net acres in 19 counties in southern New York and northern Pennsylvania. Approximately 75% of these net acres are located in eastern Allegany and western Steuben Counties in New York, an area which some industry press reports suggest may be prospective for gas production from unconventional reservoirs including the Marcellus Shale. We are monitoring industry activity and encouraging dialogue with industry participants to determine the proper course of action regarding our interests.

Liquidity and Capital Resources

Capital Resources

Our primary sources of capital are our cash flow from the Net Profits Interests and the Royalty Properties. Our only cash requirements are the distributions to our unitholders, the payment of oil and natural gas production and property taxes not otherwise deducted from gross production revenues and general and administrative expenses incurred on our behalf and allocated in accordance with our partnership agreement. Since the distributions to our unitholders are, by definition, determined after the payment of all expenses actually paid by us, the only cash requirements that may create liquidity concerns for us are the payments of expenses. Since most of these expenses vary directly with oil and natural gas sales prices and volumes, we anticipate that sufficient funds will be available at all times for payment of these expenses. See Note 4 of the Notes to the Condensed Consolidated Financial Statements for the amounts and dates of cash distributions to unitholders.

We are not directly liable for the payment of any exploration, development or production costs. We do not have any transactions, arrangements or other relationships that could materially affect our liquidity or the availability of capital resources. We have not guaranteed the debt of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

Pursuant to the terms of our partnership agreement, we cannot incur indebtedness, other than trade payables, (i) in excess of $50,000 in the aggregate at any given time or (ii) which would constitute “acquisition indebtedness” (as defined in Section 514 of the Internal Revenue Code of 1986, as amended).

Expenses and Capital Expenditures

The operating partnership plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and drilling. Costs of such techniques vary widely and are not predictable as each effort requires specific engineering. The operating partnership owns and operates the wells, pipelines and natural gas compression and dehydration facilities located in Kansas and Oklahoma. The operating partnership anticipates gradual increases in expenses as repairs to these facilities become more frequent and anticipates gradual increases in field operating expenses as reservoir pressure declines. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future. The operating partnership does not anticipate incurring significant expense to replace these facilities at this time. These capital and operating costs influence the Net Profits Interests payments we receive from the operating partnership and are included in the accrual basis production costs $/mcfe in the table under “Results of Operations.”

Liquidity and Working Capital

Cash and cash equivalents totaled $10,012,000 at September 30, 2009 and $16,211,000 at December 31, 2008.

Critical Accounting Policies

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this method, all such costs are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. Oil and natural gas properties are evaluated using the full cost ceiling test at the end of each quarter and when events indicate possible impairment.

The discounted present value of our proved oil and natural gas reserves is a major component of the ceiling calculation and requires many subjective judgments. Estimates of reserves are forecasts based on engineering and geological analyses. Different reserve engineers may reach different conclusions as to estimated quantities of natural gas reserves based on the same information. Our reserve estimates are prepared by independent consultants. The passage of time provides more qualitative information regarding reserve estimates, and revisions are made to prior estimates based on updated information. However, there can be no assurance that significant revisions will not be necessary in the future. Significant downward revisions could result in an impairment representing a non-cash charge to earnings. In addition to the impact on calculation of the ceiling test, estimates of proved reserves are also a major component of the calculation of depletion.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of our reserves are objectively determined. The ceiling test calculation requires use of prices and costs in effect as of the last day of the accounting period, which are generally held constant for the life of the properties. As a result, the present value is not necessarily an indication of the fair value of the reserves. Oil and natural gas prices have historically been volatile and the prevailing prices at any given time may not reflect our Partnership's or the industry's forecast of future prices.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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. For example, estimates of uncollected revenues and unpaid expenses from royalties and net profits interests in properties operated by non-affiliated entities are particularly subjective due to our inability to gain accurate and timely information. Therefore, actual results could differ from those estimates.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following information provides quantitative and qualitative information about our potential exposures to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates and currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses but, rather, indicators of possible losses.

Market Risk Related to Oil and Natural Gas Prices

Essentially all of our assets and sources of income are from Royalty Properties and the Net Profits Interests, which generally entitle us to receive a share of the proceeds based on oil and natural gas production from those properties. Consequently, we are subject to market risk from fluctuations in oil and natural gas prices. Pricing for oil and natural gas production has been volatile and unpredictable for several years. We do not anticipate entering into financial hedging activities intended to reduce our exposure to oil and natural gas price fluctuations.

Absence of Interest Rate and Currency Exchange Rate Risk

We do not anticipate having a credit facility or incurring any debt, other than trade debt. Therefore, we do not expect interest rate risk to be material to us. We do not anticipate engaging in transactions in foreign currencies that could expose us to foreign currency related market risk.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, our principal executive officer and principal financial officer carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective.

Changes in Internal Controls

There were no changes in our internal controls (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

See Note 2 – Contingencies in Notes to the Condensed Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 other than the following:

Federal hydraulic fracturing legislation could delay or restrict development of our oil and gas properties.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit the practice of hydraulic fracturing or subject the process to regulation. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. Although it is not possible at this time to predict the final outcome of the legislation, any new federal restrictions on hydraulic fracturing could significantly increase operating, capital and compliance costs. Such cost increases could delay or restrict development by operators of our oil and gas properties.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

See the attached Index to Exhibits.

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.

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP
its General Partner

By: Dorchester Minerals Management GP LLC
its General Partner

By: /s/ William Casey McManemin
William Casey McManemin
Chief Executive Officer

Date: November 5, 2009

By: /s/ H.C. Allen, Jr.
H.C. Allen, Jr.
Chief Financial Officer

Date: November 5, 2009

INDEX TO EXHIBITS

Number	Description
3.1	Certificate of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.1 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.2	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals, L.P. (incorporated by reference to Exhibit 3.2 to Dorchester Minerals' Report on Form 10-K filed for the year ended December 31, 2002)
3.3	Certificate of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.4	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Management LP (incorporated by reference to Exhibit 3.4 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.5	Certificate of Formation of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.7 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.6	Amended and Restated Limited Liability Company Agreement of Dorchester Minerals Management GP LLC (incorporated by reference to Exhibit 3.6 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.7	Certificate of Formation of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.8	Limited Liability Company Agreement of Dorchester Minerals Operating GP LLC (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.9	Certificate of Limited Partnership of Dorchester Minerals Operating LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Registration Statement on Form S-4, Registration Number 333-88282)
3.10	Amended and Restated Agreement of Limited Partnership of Dorchester Minerals Operating LP. (incorporated by reference to Exhibit 3.10 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.11	Certificate of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.11 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.12	Agreement of Limited Partnership of Dorchester Minerals Oklahoma LP (incorporated by reference to Exhibit 3.12 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.13	Certificate of Incorporation of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.13 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.14	

	Bylaws of Dorchester Minerals Oklahoma GP, Inc. (incorporated by reference to Exhibit 3.14 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2002)
3.15	Certificate of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.15 to Dorchester Minerals' Report on Form 10-K for the year ended December 31, 2004)
3.16	Agreement of Limited Partnership of Dorchester Minerals Acquisition LP (incorporated by reference to Exhibit 3.16 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
3.17	Certificate of Incorporation of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.17 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
3.18	Bylaws of Dorchester Minerals Acquisition GP, Inc. (incorporated by reference to Exhibit 3.18 to Dorchester Minerals' Report on Form 10-Q for the quarter ended September 30, 2004)
31.1*	Certification of Chief Executive Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer of the Partnership pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of Chief Executive Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350
32.2*	Certification of Chief Financial Officer of the Partnership pursuant to 18 U.S.C. Sec. 1350 (contained within Exhibit 32.1 hereto)

* Filed herewith