DORCHESTER MINERALS LP
Form 10-Q
November 06, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC. 20549

FORM 10-Q

[X] QUARTERLY REPORT UNDER 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, 2008	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 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	Smaller reporting company o

(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 Act.): Yes o No x

As of November 6, 2008, 28,240,431 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, 2008 (unaudited)	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 28,898	$ 15,001
Trade receivables	8,475	7,053
Net profits interests receivable - related party	3,373	3,576
Prepaid expenses	12	-
Total current assets	40,758	25,630
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	291,818	291,830
Less accumulated full cost depletion	174,758	163,582
Total	117,060	128,248
Leasehold improvements	512	512
Less accumulated amortization	195	158
Total	317	354
Net property and leasehold improvements	117,377	128,602
Total assets	$ 158,154	$ 154,251
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,305	$ 517
Current portion of deferred rent incentive	39	39
Total current liabilities	1,344	556
Deferred rent incentive less current portion	218	248
Total liabilities	1,562	804

Commitments and contingencies				
Partnership capital:				
General partner		6,532		6,417
Unitholders		150,060		147,030
Total partnership capital		156,592		153,447
Total liabilities and partnership capital	$	158,154	$	154,251

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

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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, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Operating revenues:				
Royalties	$ 18,284	$ 10,552	$ 51,659	$ 31,334
Net profits interests	6,040	4,072	22,609	15,273
Lease bonus	154	84	411	401
Other	9	8	68	35
Total operating revenues	24,487	14,716	74,747	47,043
Costs and expenses:				
Operating, including production taxes	1,491	838	4,027	2,829
Depletion and amortization	3,775	3,963	11,213	11,657
General and administrative expenses	744	775	2,615	2,485
Total costs and expenses	6,010	5,576	17,855	16,971
Operating income	18,477	9,140	56,892	30,072
Other income, net	113	334	274	607
Net earnings	$ 18,590	$ 9,474	$ 57,166	$ 30,679
Allocation of net earnings:				
General partner	$ 593	$ 293	$ 1,718	$ 895
Unitholders	$ 17,997	$ 9,181	$ 55,448	$ 29,784
Net earnings per common unit (basic and diluted)	$ 0.64	$ 0.33	$ 1.97	$ 1.05
Weighted average common units outstanding	28,240	28,240	28,240	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, 2008	Nine Months Ended September 30, 2007
Net cash provided by operating activities	$ 67,968	$ 44,583
Cash flows (used in) provided by investing activities:		
Proceeds from related party note receivable	-	38
Capital expenditures	(50)	(16)
Total cash flows (used in) provided by investing activities	(50)	22
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(54,021)	(41,105)
Increase in cash and cash equivalents	13,897	3,500
Cash and cash equivalents at beginning of period	15,001	13,927
Cash and cash equivalents at end of period	$ 28,898	$ 17,427

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, 2007.

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 on January 7, 2008, the plaintiff filed an appeal. On March 3, 2008, the appeal was dismissed by the Oklahoma Supreme Court pending disposition by the District Court of unresolved related claims. On June 23, 2008, the operating partnership dismissed, without prejudice, its counterclaim. All unresolved related claims have since been concluded and all issues, including the operating partnership's grant of summary judgment, are awaiting results of appeal to the Oklahoma Supreme Court. An adverse appellate decision could reduce amounts we receive from the Net Profits Interests.

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. Distributions to Holders of Common Units: Since commencing operations on January 31, 2003, unitholder cash distributions per common unit have been:

	Per Unit Amount					
	2003	2004	2005	2006	2007	2008
First quarter	$0.206469	$0.415634	$0.481242	$0.729852	$0.461146	$0.572300

Second quarter	$0.458087	$0.415315	$0.514542	$0.778120	$0.473745	$0.769206
Third quarter	$0.422674	$0.476196	$0.577287	$0.516082	$0.560502	$0.948472
Fourth quarter	$0.391066	$0.426076	$0.805543	$0.478596	$0.514625	

Distributions beginning with the third quarter of 2004 were paid on 28,240,431 units; previous distributions were paid on 27,040,431 units. 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, 2009.

4. New Accounting Pronouncements: In December 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 141 (revised 2007), Business Combinations, which replaces SFAS No 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase accounting. It also changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. SFAS No. 141R is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Management currently believes that the adoption of this statement will not have a material impact on the Company's financial statements.

In September 2006, the FASB issued Statement No. 157, "Fair Value Measurements" ("SFAS 157"), which defines fair value, establishes a framework to measure assets and liabilities, and expands disclosures about fair value measurements. This statement applies whenever other statements require or permit assets or liabilities to be measured at fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007, except for nonfinancial assets and liabilities that are recognized or disclosed at fair value in financial statements on a recurring basis, for which application has been deferred for one year. We adopted SFAS 157 in the first quarter of 2008 with no material impact on our consolidated 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 573 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 in property groups made up of four NPIs created when we commenced operations in 2003. We refer to our net profits overriding royalty interest in these property groups as the Net Profits Interests. 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, 2008, 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 cash receipts and disbursements attributable to the Minerals NPI:

Minerals NPI Cash Basis Results

	(in Thousands)		
	Cumulative Total at 12/31/07	Nine Months Ended 9/30/08	Cumulative Total at 9/30/08
Cash received for revenue	$ 8,200	$ 4,416	$ 12,616
Cash paid for operating costs	1,373	596	1,969
Cash paid for development costs	6,946	3,856	10,802
Net cash paid	$ (119)	$ (36)	$ (155)
Cumulative NPI deficit	$ (119)	$ (155)	$ (155)

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. Amounts in the above table include budgeted capital expenditures of $1,639,000 at September 30, 2008. The amounts also 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, 2008 as compared to Three and Nine Months Ended September 30, 2007

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			Nine Months Ended	
	September 30,		June 30,	September 30,	
Accrual basis sales volumes:	2008	2007	2008	2008	2007
Royalty properties gas sales (mmcf)	1,000	892	872	2,864	2,588
Royalty properties oil sales (mbbls)	77	77	80	229	230
Net profits interests gas sales (mmcf)	961	1,049	974	2,922	3,100
Net profits interests oil sales (mbbls)	2	4	3	9	12
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$ 9.41	$ 5.60	$ 10.73	$ 9.31	$ 6.62
Royalty properties oil sales ($/bbl)	$ 115.62	$ 72.41	$ 116.43	$ 109.33	$ 61.86
Net profits interests gas sales ($/mcf)	$ 7.76	$ 5.78	$ 11.90	$ 9.23	$ 6.78
Net profits interests oil sales ($/bbl)	N/A	$ 67.82	$ 116.81	$ 118.47	$ 56.89

Accrual basis production costs deducted under the net profits interests ($/mcfe) (1)	$ 1.90	$ 2.16	$ 1.94	$ 1.94	$ 2.10

(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 unchanged at 77 mbbls in both 2007 and 2008. Oil sales volumes attributable to our Royalty Properties during the first nine months were also virtually unchanged at 230 mbbls in 2007 compared to 229 mbbls in 2008. Natural gas sales volumes attributable to our Royalty Properties during the third quarter increased 12.1% from 892 mmcf in 2007 to 1,000 mmcf in 2008. Natural gas sales volumes attributable to our Royalty Properties during the first nine months increased 10.7% from 2,588 in 2007 to 2,864 mmcf in 2008. The increase in year-to-date natural gas sales volumes were primarily attributable to weather-related problems that negatively affected production in the first quarter and portions of the second quarter of 2007. The increase in third quarter natural gas sales volumes was primarily attributable to the results of new drilling activity on the Royalty Properties during 2008 and to a lesser degree the contribution of natural gas liquids and plant products to natural gas equivalent volumes resulting from the significant increase in crude oil prices during the summer months.

Oil sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2008 were lower when compared to the same periods of 2007 due to an operator's adjustments to production from prior periods. Natural gas sales volumes attributable to our Net Profits Interests during the third quarter and first nine months of 2008 decreased from the same periods of 2007. Third quarter sales of 961 mmcf during 2008 were 8.4% less than 1,049 mmcf during 2007. The first nine month sales of 2,922 mmcf during 2008 were 5.7% less than 3,100 mmcf during 2007. 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 price attributable to our interest in Royalty Properties increased 59.7% from $72.41/bbl during the third quarter of 2007 to $115.62/bbl during the third quarter of 2008 and increased 76.7% from $61.86/bbl during the first nine months of 2007 to $109.33/bbl during the same period of 2008. The third quarter weighted average natural gas sales price from Royalty Properties increased 68.0% from $5.60/mcf during 2007 to $9.41/mcf during 2008. The nine months ended September 30 weighted average Royalty Properties natural gas sales price increased 40.6% from $6.62/mcf during 2007 to $9.31/mcf during 2008. Both oil and natural gas price changes resulted from changing market conditions.

The third quarter weighted average oil sales price from the Net Profits Interests' properties increased from 2007 levels. However, due to the small amount of oil production, the third quarter oil price was highly distorted by an operator's adjustments to production from prior periods. We have not shown such average price in the table above to avoid undue confusion. The first nine months Net Profits Interests' oil sales price increased 108.2% from $56.89/bbl in 2007 to $118.47/bbl in 2008. Changing market conditions and production adjustments for prior periods mentioned previously resulted in increased oil prices. The weighted average natural gas sales price attributable to the Net Profits Interests increased during the third quarter of 2008 compared to the same period of 2007 and increased from the first nine months of 2007 to the same period of 2008. The third quarter natural gas sales price of $7.76/mcf in 2008 was 34.3% more than $5.78/mcf in 2007. The nine months ended September 30, 2008 weighted average natural gas sales price increased 36.1% to $9.23/mcf from $6.78/mcf in the same period of 2007. Natural gas sales price increases during the three-and nine-month periods resulted from changing market conditions plus a natural gas liquid payment received in the second quarter 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. We will evaluate such payment at the end of annual contract period and will accrue such revenue when payment is determinable and collectability is assured. Only immaterial amounts were received prior to 2007.

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 2008 third quarter totaled $19,794,000. These receipts generally reflect oil sales during June through August 2008 and natural gas sales during May through July 2008. The weighted average indicated price for oil and natural gas sales during the 2008 third quarter attributable to the Royalty Properties was $124.82/bbl and $10.89/mcf, respectively.

Cash receipts attributable to our Net Profits Interests during the 2008 third quarter totaled $8,783,000. These receipts reflect oil and natural gas sales from the properties underlying the Net Profits Interests generally during May through July 2008. The weighted average indicated price received during the 2008 third quarter for oil and natural gas sales was $121.61/bbl and $10.22/mcf, respectively.

Our third quarter net operating revenues increased 66.4% from $14,716,000 during 2007 to $24,487,000 during 2008. Net operating revenues for the first nine months of 2008 increased 58.9% from $47,043,000 during 2007 to $74,747,000 during 2008. Both the quarterly and nine month increase resulted from increased gas and oil sales prices including a 2007 natural gas liquid payment received during the second quarter 2008.

Costs and expenses increased 7.8% from $5,576,000 during the third quarter of 2007 to $6,010,000 during the third quarter of 2008, while nine months ended September 30 costs and expenses increased 5.2% from $16,971,000 during 2007 to $17,855,000 during 2008. Such increases primarily resulted from increased production tax on higher operating revenues.

Depletion and amortization decreased 4.7% during the third quarter ended September 30, 2008 and 3.8% during the nine months ended September 30, 2008 when compared to the same periods of 2007. The decreases from $3,963,000 and $11,657,000 during the third quarter and nine months ended September 30, 2007, respectively, to $3,775,000 and $11,213,000 during the same periods of 2008 respectively, resulted from a lower depletable base due to effects of previous depletion and upward revisions in oil and natural gas reserve estimates at 2007 year end.

Third quarter net earnings allocable to common units increased 96.0% from $9,181,000 during 2007 to $17,997,000 during 2008. The first nine months common unit net earnings increased 86.2% from $29,784,000 during 2007 to $55,448,000 during 2008. The 2008 increase from the third quarter 2007 and the first nine months 2007 net earnings is primarily the result of increased oil and natural gas sales prices.

Net cash provided by operating activities increased 68.4% from $16,675,000 during the third quarter of 2007 to $28,082,000 during the third quarter of 2008 and increased 52.5% from $44,583,000 for the first nine months during 2007 to $67,968,000 during the same period of 2008. Increases in both periods are primarily due to increased oil and natural gas sales prices along with abnormal natural gas liquid payments. See discussion above on net operating revenues for more details.

We received cash payments in the amount of $268,000 from various sources during the third quarter of 2008 including lease bonuses attributable to eight consummated leases and pooling elections located in seven counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $500/acre.

We received division orders for, or otherwise identified, 121 new wells completed on our Royalty Properties and Net Profits Interests located in 47 counties and parishes in 10 states during the third quarter of 2008. The operating partnership elected to participate in 14 wells to be drilled on our Net Profits Interests located in five counties in two states. 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 following table.

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

	County			DMLP	DMOLP		Test Rates per day	
State	/Parish	Operator	Well Name	NRI(2)	WI(1)	NRI(2)	Gas, mcf	Oil, bbls
ND	Dunn	Marathon Oil Co.	Scott #24-31H	1.377%	--	--	171	327
OK	Washita	JMA Energy	Kellogg #1-13	0.417%	--	--	2,573	184
OK	Woodward	Chesapeake Operating	Alva #1-34	3.750%	--	--	753	--
OK	Woodward	Chesapeake Operating	United #1-34	3.750%	--	--	399	12
TX	Hidalgo	El Paso E & P Co.	Coates A-41	6.382%	--	--	1,577	--
TX	Jackson	Chesapeake Operating	Kubecka #3	3.784%	--	--	4,734	--

TX	Starr	Ascent Operating	Garza Hitchcock #14	2.653%	--	--	2,870	--
TX	Starr	Ascent Operating	Garza Hitchcock #17	2.653%	--	--	2,715	--
TX	Starr	El Paso E & P Co.	Cow Creek Corporation #3	10.242%	--	--	14,812	--

(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 nine wells have been permitted on the lands as of September 30, 2008. 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 wells completed 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	SEECO	Green Bay Packaging 9-15 #3-18H19	0.252%	0.000%	0.000%	3,356
Conway	SEECO	Green Bay Packaging 9-15 #4-18H19	0.259%	0.000%	0.000%	3,985
Conway	SEECO	Green Bay Packaging 9-15 #4-29H30	2.099%	1.968%	1.502%	3,113
Conway	SEECO	McCoy 8-16 #2-1H	6.250%	5.000%	3.750%	536
Conway	SEECO	Polk 9-15 #3-30H	5.930%	5.561%	4.245%	--
Faulkner	Chesapeake	Hardy 7-13 #1-5H	1.577%	2.109%	1.689%	1,649
Faulkner	Petrohawk	Jolly 8-12 #2-9H	0.977%	0.000%	0.000%	--
Van Buren	SEECO	Love 10-12 #3-17H16	3.442%	5.052%	3.793%	1,618
Van Buren	Chesapeake	Bradley 11-13 #1-9H	1.563%	1.250%	0.938%	1,859
Van Buren	Petrohawk	Smith 11-13 #2-30H	0.684%	0.000%	0.000%	954
Van Buren	SH Exploration	Chavez 11-16 #1-8H	4.688%	5.000%	3.750%	785
Van Buren	SH Exploration	Chavez 11-16 #2-8H	4.688%	5.000%	3.750%	642

(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 is a summary of all permitting, drilling and completion activity through September 30, 2008 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI, which is currently in a deficit status.

	2004	2005	2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Total
New Well Permits	1	2	11	4	9	12	11	18	26	15	109
Wells Spud	0	1	9	4	7	9	13	12	17	21	93
Wells Completed	0	1	5	2	4	8	9	10	17	12	68
Wells in Pay Status (1)	0	1	0	2	3	3	6	4	7	14	40

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

Net cash receipts for the Royalty Properties attributable to interests in these lands totaled $713,000 in the third quarter from 29 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled $878,000 in the third quarter.

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 circulated a Request for Proposal to industry participants in May 2008 to solicit expressions of interest to lease or jointly develop our interests in this area. As of October 27, 2008, we have not received any proposals. We will continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests.

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. Fifty-four wells have been permitted on these lands as of September 30, 2008. 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,

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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 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 is a summary of all permitting, drilling and completion activity through September 30, 2008 for wells in which we have a royalty or Net Profits Interest.

	2004	2005	2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Total
New Well Permits	2	1	0	2	4	4	5	8	15	13	54
Wells Spud	1	1	0	1	2	4	4	2	10	8	33
Wells Completed	1	1	0	0	1	4	2	5	3	3	20
WI Wells in Pay Status(1)	0	0	0	0	0	0	0	0	1	0	1

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

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 3 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

In the Oklahoma Guymon-Hugoton field, the operating partnership perforated two additional zones in two wells and re-perforated/fracture treated one well during the third quarter of 2008. Total costs on the three wells were $147,000 and total increase in gas production was 31 mcf per day. The operating partnership plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and replacing existing wells. Based on prior efforts, costs vary widely and are not predictable as each effort requires specific engineering. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests as reflected in the accrual basis production costs $/mcfe in the table under "Results of Operations."

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 does not anticipate incurring significant expense to replace these facilities at this time. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future. These capital and operating costs are reflected in the Net Profits Interests payments we receive from the operating partnership.

In 1998, Oklahoma regulations removed production quantity restrictions in the Guymon-Hugoton field and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Infill drilling could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable and could influence the amount we receive from the Net Profits Interests.

Liquidity and Working Capital

Cash and cash equivalents totaled $28,898,000 at September 30, 2008 and $15,001,000 at December 31, 2007.

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 effectively ensure that the information required to be disclosed in the reports we file with the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission.

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, 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls subsequent to the date of their evaluation of our disclosure controls and procedures.

PART II

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

None.

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.

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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 6, 2008

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

Date: November 6, 2008

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)