DORCHESTER MINERALS LP
Form 10-Q
May 04, 2007

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 March 31, 2007   Commission file number 000-50175

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer   Accelerated filer X Non-accelerated filer

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

As of May 3, 2007, 28,240,431 common units of partnership interest were outstanding.

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DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

Statements included in this report which 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 discuss 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 "us," "our," "we," and "its" are sometimes used 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 herein 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.

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

CONDENSED BALANCE SHEETS
(In Thousands)

	March 31, 2007	December 31, 2006
ASSETS	(unaudited)	
Current assets:		
Cash and cash equivalents	$ 13,828	$ 13,927
Trade receivables	5,894	6,088
Net profits interests receivable - related party	3,871	4,126
Current portion of note receivable - related party	42	50
Prepaid expenses	37	-
Total current assets	23,672	24,191
Note receivable - related party less current portion	-	5
Other non-current assets	19	19
Total	19	24
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method):	291,875	291,875
Less accumulated full cost depletion	151,873	148,064
Total	140,002	143,811
Leasehold improvements	512	512
Less accumulated amortization	121	109
Total	391	403
Net property and leasehold improvements	140,393	144,214
Total assets	$164,084	$168,429
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 722	$ 303
Distributions payable to partners	44	-
Current portion of deferred rent incentive	39	39
Total current liabilities	805	342
Deferred rent incentive less current portion	277	287
Total liabilities	1,082	629
Commitments and contingencies		
Partnership capital:		
General partner	6,652	6,797
Unitholders	156,350	161,003
Total partnership capital	163,002	167,800
Total liabilities and partnership capital	$164,084	$168,429

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

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

CONDENSED STATEMENTS OF OPERATIONS
(Dollars In Thousands, Except Per Unit Amounts)
(Unaudited)

	Three Months Ended March 31, 2007	2006
Operating revenues:		
Net profits interests	$ 4,944	$ 6,556
Royalties	9,669	11,947
Lease bonus	93	764
Other	8	12
Total operating revenues	14,714	19,279
Cost and expenses:		
Operating, including production taxes	968	850
Depletion and amortization	3,821	4,708
General and administrative expenses	943	853
Total costs and expenses	5,732	6,411
Operating income	8,982	12,868
Other income, net	141	192
Net earnings	$ 9,123	$ 13,060
Allocation of net earnings:		
General partner	$ 260	$ 378
Unitholders	$ 8,863	$ 12,682
Net earnings per common unit (in dollars)	$ 0.31	$ 0.45
Wtd. avg. common units outstanding (000's)	28,240	28,240

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

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

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

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Net cash provided by operating activities	$ 13,765	$ 21,494
Cash flows provided by investing activities:		
Proceeds from related party note receivable	13	13
Total cash flows provided by investing activities	13	13
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(13,877)	(23,382)
Decrease in cash and cash equivalents	(99)	(1,875)
Cash and cash equivalents at January 1,	13,927	23,389
Cash and cash equivalents at March 31,	$ 13,828	$ 21,514

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

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

NOTES TO THE CONDENSED 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 condensed 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 income applicable to holders of our common units by the weighted average number of units outstanding. Certain amounts in the 2006 financial statements have been reclassified to conform with the 2007 presentation. Such reclassifications did not impact net income, or total assets, or total liabilities.

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. 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. The plaintiffs consist primarily of Texas County, Oklahoma residents who, in residences located

on leases use natural gas from gas wells located on the same leases, at their own risk, free of cost. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas leases entered into in the 1930s to the 1950s. Plaintiffs' claims against defendants include failure to prudently operate wells, violation of rights to free domestic gas, and fraud. Plaintiffs also seek certification of class action against defendants. On October 1, 2004, the plaintiffs severed claims against the operating partnership regarding royalty underpayments. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding domestic gas use. The operating partnership believes plaintiffs' remaining claim regarding royalty underpayments is completely without merit. An adverse 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 financial position 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 or will be:

	Per Unit Amount				
	2003	2004	2005	2006	2007
First Quarter	$0.206469	$0.415634	$0.481242	$0.729852	$0.461146
Second Quarter	$0.458087	$0.415315	$0.514542	$0.778120	
Third Quarter	$0.422674	$0.476196	$0.577287	$0.516082	
Fourth Quarter	$0.391066	$0.426076	$0.805543	$0.478596	

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 August 15, 2007.

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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 interests properties and a minor portion of mineral and royalty interest properties. We refer to Dorchester Minerals Operating LP as the "operating partnership." We directly and indirectly own a 96.97% net profits overriding royalty interest in four property groups, the three created when we commenced operations and the 2003-2006 NPI. We refer to our net profits overriding royalty interest in these property groups as the Net Profits Interests. We 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.

In accordance with our partnership agreement we have the continuing right and obligation to create additional Net Profits Interests by transferring properties to the operating partnership subject to the reservation of a Net Profits Interest identical to the Net Profit Interests created when we commenced operations in 2003. The purpose of such Net Profits Interests is to avoid the Partnership's participation as a working interest or other cost expense-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 was created for each of calendar years 2003 through 2006 by transferring various properties to the operating partnership subject to a Net Profits Interest. These interests were subsequently combined and we currently refer to them as the 2003-2006 NPI which is our fourth separate Net Profits Interest. As of March 31, 2007, cumulative operating and development costs presented in the following table, which include amounts equivalent to an interest charge, exceeded cumulative revenues of the 2003-2006 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 2003-2006 NPI recovers the deficit amount. Once in profit status, we will receive the Net Profits Interest payment attributable to these properties. Our 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 2003-2006 NPI.

The following table sets forth cash receipts and disbursements attributable to the 2003-2006 Net Profits Interest:

	2003-2006 Net Profits Interest Cash Basis Results (in Thousands)		
	Cumulative Total at December 31, 2006	Three Months Ended March 31, 2007	Cumulative Total at March 31, 2007
Cash received for revenue	$4,945	$ 634	$ 5,579
Cash paid for operating costs	(852)	(106)	(958)
Cash paid for development costs	(4,311)	(504)	(4,815)
Net cash (paid) received	$ (218)	$ 24	$ (194)
Cumulative NPI Deficit	$ (218)	$ (194)	$ (194)

The development costs pertain to more properties than the properties producing revenue due to timing differences between operating partnership expenditures and oil and gas production and payments to the operating partnership. Amounts in the above table 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 2003-2006 NPI may not be indicative of future results of the 2003-2006 NPI and may not indicate when the deficit status may end and when Net Profits Interests payment may begin from the 2003-2006 NPI.

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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 and general market volatility.

Results of Operations

Three Months Ended March 31, 2007 as compared to Three Months Ended March 31, 2006

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 March 31,	
Accrual Basis Sales Volumes:	2007	2006
Royalty Properties Gas Sales (mmcf)................	858	965
Royalty Properties Oil Sales (mbbls)...............	74	85
Net Profits Interests Gas Sales (mmcf).............	1,016	1,126
Net Profits Interests Oil Sales (mbbls)............	4	3
Accrual Basis Weighted Average Sales Price:		
Royalty Properties Gas Sales ($/mcf)...............	$ 6.60	$ 7.39
Royalty Properties Oil Sales ($/bbl)...............	$53.87	$56.67
Net Profits Interests Gas Sales ($/mcf)............	$ 6.74	$ 7.42
Net Profits Interests Oil Sales ($/bbl)............	$46.41	$47.04
Accrual Basis Production Costs Deducted Under the Net Profits Interests ($/mcfe) (1)........	$ 2.08	$ 1.75

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

Oil sales volumes attributable to our Royalty Properties during the first quarter decreased 12.9% from 85 mbbls in 2006 to 74 mbbls in 2007. Natural gas sales volumes attributable to our Royalty Properties during the first quarter decreased 11.1% from 965 mmcf in 2006 to 858 mmcf in 2007. The decreases in oil and natural gas sales volumes were primarily attributable to wells completed in the T-Patch Field in early 2006. As previously reported, these wells have exhibited significant production declines after initially producing at anomalously high rates. In addition, Royalty Properties located in the Mid-Continent experienced weather-related production disruptions in January.

Oil sales volumes attributable to our Net Profits Interests during the first quarter of 2007 were virtually unchanged from 2006. Natural gas sales volumes attributable to our Net Profits Interests during the first quarter decreased 9.8% from 1,126 mmcf during 2006 to 1,016 mmcf during 2007 due to natural reservoir decline, scheduled equipment and facility maintenance and weather-related production disruptions in January. Production sales volumes and prices from the 2003-2006 NPI are excluded from the above table. See "Overview" above.

Weighted average oil sales prices attributable to our interest in Royalty Properties decreased 4.9% from $56.67/bbl during the first quarter of 2006 to $53.87/bbl during the first quarter of 2007. Similarly, first quarter weighted average natural gas sales prices from Royalty Properties decreased

10.7% from $7.39/mcf during 2006 to $6.60/mcf during 2007. Both oil and natural gas price decreases resulted from changing market conditions.

First quarter weighted average oil sales prices from the Net Profits Interests' properties decreased 1.3% from $47.04/bbl in 2006 to $46.41/bbl in 2007. First quarter weighted average natural gas sales prices from the Net Profits Interests' properties decreased 9.2% from $7.42/mcf in 2006 to $6.74/mcf in 2007. Such oil and natural gas price decreases resulted from changing market conditions.

In an effort to provide the reader with information concerning prices of oil and 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 gas may be described generally, actual cash receipts may be materially impacted by purchasers' release of suspended funds and by prior period adjustments.

Cash receipts attributable to our Net Profits Interests during the 2007 first quarter totaled $5,199,000. These receipts generally reflect oil and gas sales from the properties underlying the Net Profits Interests during November 2006 through January 2007. The weighted average indicated prices for oil and gas sales during the 2007 first quarter attributable to the Net Profits Interests were $45.90/bbl and $6.43/mcf, respectively.

Cash receipts attributable to our Royalty Properties during the 2007 first quarter totaled $9,274,000. These receipts generally reflect oil sales during December 2006 through February 2007 and gas sales during November 2006 through January 2007. The weighted average indicated prices for oil and gas sales during the 2007 first quarter attributable to the Royalty Properties were $53.25/bbl and $6.59/mcf, respectively.

Our first quarter net operating revenues decreased 23.7% from $19,279,000 during 2006 to $14,714,000 during 2007 primarily as a result of decreased oil and gas sales prices and volumes. Additionally, first quarter 2006 net operating revenues included a non-refundable lease bonus payment of $616,000 related to our Arkansas lease transactions.

Costs and expenses decreased 10.6% from $6,411,000 during the first quarter of 2006 to $5,732,000 during the first quarter of 2007. Such decreases primarily resulted from decreased depletion and amortization.

Depletion and amortization decreased 18.8% during the first quarter ended March 31, 2007 when compared to the same period of 2006. The decrease from $4,708,000 to $3,821,000 resulted from a lower depletable base due to effects of previous depletion and upward revisions in oil and gas reserve estimates at 2006 year end.

We received cash payments in the amount of $270,000 from various sources during the first quarter of 2007 including lease bonuses attributable to 13 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 $300/acre.

We received division orders, or otherwise identified, 75 new wells completed on our Royalty Properties and Net Profit Interests located in 32 counties and parishes in 10 states during the first quarter of 2007. The operating partnership elected to participate in nine wells to be drilled on our Net Profits Interests located in six counties in three 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 and discussion. Wells detailed in the Fayetteville Shale discussion are excluded from this table:

State	County/Parish	Operator	Well Name	Ownership		Test R
				WI(1)	NRI(1)	Gas, m
Royalty Properties						
TX	Starr	Petrohawk Energy Corp	Cleopatra #5	--	1.625%	10,3
OK	Roger Mills	Conoco Phillips	Smith 6-5	--	1.871%	4,1
TX	Starr	Ascent Operating, LP	Garza Hitchcock #10	--	2.653%	2,1
TX	Panola	Chesapeake Operating	Bill Powers A #6	--	5.521%	9
TX	Hidalgo	Samson Lone Star LP	Schlaben #6	--	3.125%	1,5
OK	Woodward	Chesapeake Operating	Vera Mae 1-34	--	3.750%	9
AR	Logan	The Houston Expl Co	Lowder GU 7-2	--	0.459%	7,7
OK	Beckham	Apache Corp.	Perryman 8-25	--	1.489%	1,8
Net Profits Interests						
MT	Richland	Slawson Exploration	Saber 1-4H	1.645%	1.645%	
ND	Mountrail	Petro-Hunt	Rice 10B-2-1H	0.175%	0.175%	

(1) WI and NRI mean working interest and net revenue interest, respectively.

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. Nineteen wells have been permitted on the lands as of April 27, 2007. Wells which 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. Information concerning the permitted wells is set forth below:

			DMLP	DMOLP		
County	Operator	Well Name	NRI(2)	WI(1)	NRI(2)	Mcf

Cleburne	SEECO	Mulliniks 9-12 #1-35H	7.266%	5.000%	3.750%	
Cleburne	SEECO	Mulliniks 9-12 #2-35H	7.266%	5.000%	3.750%	
Cleburne	SEECO	Mulliniks 9-12 #3-35H	7.266%	5.000%	3.750%	
Conway	SEECO	Beck 8-16 #1-1H	10.000%	5.000%	3.750%	
Conway	Arrington	Beverly Crofford #1-14 H	2.500%	1.250%	0.938%	
Conway	SEECO	Jerome Carr #1-31H	5.054%	3.796%	2.847%	1
Conway	SEECO	Jerome Carr #2-31H	5.054%	3.796%	2.847%	3
Conway	SEECO	Polk 09-15 #1-30H	10.114%	5.556%	4.216%	
Pope	Penn Virginia	Brown #1-33H	2.500%	1.250%	0.938%	
Pope	Penn Virginia	Tackett #1-33H	2.500%	1.250%	0.938%	
Van Buren	SEECO	Hillis #1-27	6.250%	6.250%	6.250%	
Van Buren	SEECO	Hillis #1-27H	0.781%	0.000%	0.781%	2
Van Buren	SEECO	Jones 10-16 #1-33H	3.125%	3.125%	3.125%	2
Van Buren	SEECO	Jones 10-16 #2-33H	3.125%	3.125%	3.125%	
Van Buren	SEECO	Quattlebaum #1-32H	0.781%	0.000%	0.000%	1
Van Buren	SEECO	Quattlebaum #2-32H	0.781%	0.000%	0.000%	
Van Buren	SEECO	Russell #1-33H	6.250%	6.250%	6.250%	2
Van Buren	SEECO	Russell #2-33H	6.250%	6.250%	6.250%	
White	Chesapeake	Hays 8-6 #1-18H	0.781%	0.000%	0.000%	

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

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

First quarter net earnings allocable to common units decreased 30.1% from $12,682,000 during 2006 to $8,863,000 during 2007. The 2007 decrease from first quarter 2006 net earnings is primarily a result of decreased 2007 oil and gas sales prices and decreased gas sales volumes.

Net cash provided by operating activities decreased 36.0% from $21,494,000 during the first quarter of 2006 to $13,765,000 during the first quarter of 2007 due to market pricing of oil and gas sales which resulted in more income as well as higher receivables in first quarter 2006. See discussion above on volumes and prices.

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 prices and sales 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 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

During February 2007 the operating partnership drilled one replacement Guymon-Hugoton well and one Council Grove formation well, both in Oklahoma. The Guymon-Hugoton well is awaiting connection to a pipeline. The Council Grove well was a dry hole costing approximately $280,000. Final cost of the replacement Guymon-Hugoton well is expected to be $430,000.

During 2007, depending upon rig availability, the operating partnership anticipates drilling one additional well in the Oklahoma Council Grove formation. The operating partnership does not otherwise currently anticipate drilling additional wells as a working interest owner/operator in the Oklahoma or Kansas properties. Successful activities by others or other developments could prompt a reevaluation of this position. Present drilling and completion costs are estimated at $350,000 - $450,000 per well. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership anticipates continuing fracture treating in its Oklahoma properties but is unable to predict the cost as a specific engineering study is required for each fracture treatment. Previous fracture treatments in these properties have cost between $50,000 and $80,000 per well. They did not require casing repairs. Such activities by the operating partnership could influence the amount we receive from the Net Profits Interests.

The operating partnership owns and operates the wells, pipelines and 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. 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. The operating partnership believes it now has sufficient field compression and permits for vacuum operation for the foreseeable future.

Liquidity and Working Capital

Cash and cash equivalents totaled $13,828,000 at March 31, 2007 and $13,927,000 at December 31, 2006.

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 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 more 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 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 reasonably possible losses.

Market Risk Related to Oil and Natural Gas Prices

Essentially all of our assets and sources of income are from the Royalties 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 which 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 March 31, 2007 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, to the 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.

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

/s/ William Casey McManemin

William Casey McManemin
Chief Executive Officer

Date: May 3, 2007

/s/ H.C. Allen, Jr.

H.C. Allen, Jr.
Chief Financial Officer

Date: May 3, 2007

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)