DORCHESTER MINERALS, L.P.
Form 10-Q
November 02, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011
Or

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

For the transition period from __________ to __________

Commission file number 000-50175

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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):

Non-accelerated filer o

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

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

As of November 2, 2011, 30,675,431 common units representing limited partnership interests were outstanding.

TABLE OF CONTENTS

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 – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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, 2011 (unaudited)	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 15,739	$ 11,253
Trade and other receivables	6,470	5,548
Net profits interests receivable - related party	3,754	3,651
Prepaid expenses	12	-
Total current assets	25,975	20,452
Other non-current assets	19	19
Total	19	19
Property and leasehold improvements - at cost:		
Oil and natural gas properties (full cost method)	344,196	344,194
Accumulated full cost depletion	(225,365)	(211,761)
Total	118,831	132,433
Leasehold improvements	512	512
Accumulated amortization	(341)	(305)
Total	171	207
Net property and leasehold improvements	119,002	132,640
Total assets	$ 144,996	$ 153,111
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable and other current liabilities	$ 1,455	$ 542
Current portion of deferred rent incentive	39	39
Total current liabilities	1,494	581
Deferred rent incentive less current portion	99	129
Total liabilities	1,593	710
Commitments and contingencies (Note 2)		
Partnership capital:		
General partner	4,385	4,669
Unitholders	139,018	147,732
Total partnership capital	143,403	152,401

Total liabilities and partnership capital	$	144,996	$	153,111

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues:				
Royalties	$ 13,841	$ 11,631	$ 40,075	$ 34,299
Net profits interests	4,405	2,358	8,498	8,029
Lease bonus	56	2,417	386	3,817
Other	24	61	90	117
Total operating revenues	18,326	16,467	49,049	46,262
Costs and expenses:				
Operating, including production taxes	1,212	1,100	3,685	3,247
Depletion and amortization	4,817	5,068	13,640	13,842
General and administrative expenses	828	782	2,745	2,806
Total costs and expenses	6,857	6,950	20,070	19,895
Operating income	11,469	9,517	28,979	26,367
Other income, net	37	19	37	27
Net earnings	$ 11,506	$ 9,536	$ 29,016	$ 26,394
Allocation of net earnings:				
General partner	$ 367	$ 335	$ 986	$ 897
Unitholders	$ 11,139	$ 9,201	$ 28,030	$ 25,497
Net earnings per common unit (basic and diluted)	$ 0.36	$ 0.30	$ 0.91	$ 0.84
Weighted average common units outstanding	30,675	30,675	30,675	30,400

The accompanying condensed notes are an integral part of these condensed 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, 2011	2010
Net cash provided by operating activities	$ 42,506	$ 42,892
Cash flows used in investing activities:		
Adjustment related to acquisition of natural gas properties	-	683
Capital expenditures	(6)	(119)
Total cash flows (used in) provided by investing activities	(6)	564
Cash flows used in financing activities:		
Distributions paid to general partner and unitholders	(38,014)	(37,226)
Increase in cash and cash equivalents	4,486	6,230
Cash and cash equivalents at beginning of period	11,253	10,124
Cash and cash equivalents at end of period	$ 15,739	$ 16,354
Non-cash investing and financing activities:		
Value of units issued for natural gas properties acquired	$ -	$ 17,685

The accompanying condensed notes are an integral part of these condensed 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. and its wholly-owned subsidiaries Dorchester Minerals Oklahoma LP, Dorchester Minerals Oklahoma GP, Inc., Maecenas Minerals LLP, and Dorchester-Maecenas GP LLC. 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, 2010.

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

2 Contingencies: In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights sued Dorchester Hugoton, Ltd., along with several other operators in Texas County, Oklahoma regarding the use of natural gas from the wells in residences. Dorchester Minerals Operating LP, the operating partnership, now owns and operates the properties formerly owned by Dorchester Hugoton. These properties contribute a major portion of the NPI amounts paid to us. On April 9, 2007, plaintiffs, for immaterial costs, dismissed with prejudice all claims against the operating partnership regarding such residential gas use. On October 4, 2004, the plaintiffs filed severed claims against the operating partnership regarding royalty underpayments, which the Texas County District Court subsequently dismissed with a grant of time to replead. On January 27, 2006, one of the original plaintiffs again sued the operating partnership for underpayment of royalty, seeking class action certification. On October 1, 2007, the Texas County District Court granted the operating partnership’s motion for summary judgment finding no royalty underpayments. Subsequently, the District Court denied the plaintiff’s motion for reconsideration, and the plaintiff filed an appeal. On March 31, 2010, the appeal decision reversed and remanded to the Texas County District Court to resolve material issues of fact. On June 30, 2011, the District Court issued a revised partial summary judgment in favor of the operating partnership. A claim of underpayment of royalty remains pending. An adverse final decision could reduce amounts we receive from the NPIs.

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

3 Acquisition for Units: On March 31, 2010, Dorchester Minerals, LP and a newly formed subsidiary acquired all of the outstanding partnership interests in Maecenas Minerals, LLP, a Texas limited liability partnership that owns

producing and nonproducing mineral and royalty interests located in 17 states, in exchange for 835,000 common units of Dorchester Minerals, L.P. valued at $17,685,000 and issued pursuant to a shelf registration statement. The Condensed Consolidated Balance Sheets presented include $17,121,000 in property additions as well as other assets and liabilities acquired. After the issuance, 2,565,000 units remain available under the shelf registration statement.

4 Distributions to Holders of Common Units: Unitholder cash distributions per common unit since 2007 have been:

	Per Unit Amount				
	2011	2010	2009	2008	2007
First quarter	$ 0.426745	$ 0.449222	$ 0.401205	$ 0.572300	$ 0.461146
Second quarter	$ 0.417027	$ 0.412207	$ 0.271354	$ 0.769206	$ 0.473745
Third quarter	$ 0.455546	$ 0.471081	$ 0.286968	$ 0.948472	$ 0.560502
Fourth quarter		$ 0.354074	$ 0.321540	$ 0.542081	$ 0.514625

5

Distributions from first quarter of 2010 through the present were paid on 30,675,431 units; distributions from the second quarter of 2009 through the fourth quarter of 2009 were paid on 29,840,431 units; previous distributions above were paid on 28,240,431 units. The third quarter 2011 distribution will be paid on November 3, 2011. 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, 2012.

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

The following discussion contains forward-looking statements. For a description of limitations inherent in forward-looking statements, see page 1 of this Form 10-Q.

Overview

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

Dorchester Minerals Operating LP is a Delaware limited partnership owned directly and indirectly by our general partner. We refer to Dorchester Minerals Operating LP as the "operating partnership" or "DMOLP." The operating partnership owns cost bearing interests (including working interests and participating mineral interests) and a minor amount of producing and nonproducing mineral and royalty interest properties. We (Dorchester Minerals, L.P.) directly and indirectly own 96.97% net profits overriding royalty interests (individually referred to as an NPI, or collectively as NPIs) in the properties owned by the operating partnership in six distinct groups. NPIs are transaction structures utilized to avoid recognition of unrelated business taxable income attributable to participating, working and other cost bearing interests in oil and gas properties. NPI payments are considered royalty payments for tax purposes. Four NPIs were created prior to our formation in 2003 and two NPIs were created as a result of acquisitions consummated since our formation.

An additional NPI, referred to as the Minerals NPI, owns cost bearing interests associated with nonproducing mineral, royalty and leasehold interest properties acquired upon our formation. All of the cost bearing interests owned by the Minerals NPI were created subsequent to our formation. The Minerals NPI recently achieved a cumulative net profit status as a result of its cumulative net revenue exceeding cumulative operating and actual and budgeted capital expenditures and development costs. As of September 30, 2011 cumulative net profit was approximately $382,000, resulting in an NPI payment of approximately $370,000 from Operating to us in October 2011. Our fourth quarter limited partner distribution will reflect this payment, plus payments for November and December, if any. Our consolidated financial statements reflect activity attributable to the Minerals NPI for the first time and include a portion of September 2011 cash receipts and disbursements and accrued revenues and costs not yet received or paid. Prior to the Minerals NPI achieving a cumulative payout status, activity attributable to the Minerals NPI was not reflected in our consolidated financial statements in accordance with generally accepted accounting principles. Our consolidated financial statements will in the future reflect activity attributable to the Minerals NPI regardless of its net profit status on a cumulative or reporting period basis. As of September 30, 2011 each of the six NPIs has cumulative revenue that exceeds cumulative costs, such excess constituting net proceeds on which NPI payments are determined. In the event an NPI has a deficit of cumulative revenue versus cumulative costs, the deficit will be borne solely by the operating partnership.

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

Minerals NPI Results

	(in Thousands)			
	Cumulative Total at 12/31/10	Nine Months Ended 9/30/11	Cumulative Total at 9/30/11	Included in Financial Statements
Cash received for revenue	$25,525	$8,080	$33,605	$351
Cash paid for operating costs	4,823	1,499	6,322	65
Cash paid for development costs	19,321	4,028	23,349	218
Budgeted capital expenditures	4,425	(873)	3,552	(314)
Net	$(3,044)	$3,426	$382	$382

Properties located in the Fayetteville Shale Trend of Northeast Arkansas, the Bakken Trend of Montana and North Dakota, and the Permian Basin of West Texas and Southeast New Mexico represent approximately 27%, 38% and 31% of the cumulative revenue less operating costs (on a cash basis) for the nine months ended 9/30/11 listed above. Many of the properties to which the development costs identified above are attributable are not now and may never be productive of hydrocarbons. Consequently, significant timing differences may and do occur between the recognition of the operating partnership's obligation to fund development costs and its receipt of revenue associated with such costs, if any. Cumulative operating and development costs include amounts equivalent to an interest charge. The amounts reflect the operating partnership's ownership share of the subject properties. NPI 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 is not indicative of future results of the Minerals NPI and is not indicative of whether NPI payments will continue 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, 2011 as compared to Three and Nine Months Ended September 30, 2010

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

	Three Months Ended September 30,		June 30,	Nine Months Ended September 30,	
Accrual basis sales volumes:	2011	2010	2011	2011	2010
Royalty properties gas sales (mmcf)	1,585	1,412	1,558	4,486	3,749
Royalty properties oil sales (mbbls)	86	82	81	245	244
NPI gas sales (mmcf)	990	856	778	2,553	2,526
NPI oil sales (mbbls)	14	2	2	18	7
Accrual basis weighted average sales price:					
Royalty properties gas sales ($/mcf)	$ 3.94	$ 4.11	$ 3.95	$ 3.95	$ 4.40
Royalty properties oil sales ($/bbl)	$ 87.69	$ 71.23	$ 98.44	$ 91.17	$ 73.04
NPI gas sales ($/mcf)	$ 4.10	$ 4.08	$ 4.33	$ 4.19	$ 4.50
NPI oil sales ($/bbl)	$ 82.74	$ 64.54	$ 97.02	$ 84.68	$ 68.06
Accrual basis production costs deducted under the NPIs ($/mcfe) (1)	$ .93	$ 1.57	$ 2.11	$ 1.56	$ 1.60

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

Oil sales volumes attributable to our Royalty Properties during the third quarter were up 4.9% from 82 mbbls during the third quarter of 2010 to 86 mbbls in the same period of 2011. Oil sales volumes attributable to our Royalty Properties during the first nine months were about the same at 244 mbbls in 2010 compared to 245 mbbls in 2011. Natural gas sales volumes attributable to our Royalty Properties during the third quarter increased 12.3% from 1,412 mmcf in 2010 to 1,585 mmcf in 2011. Natural gas sales volumes attributable to our Royalty Properties during the first nine months increased 19.7% from 3,749 in 2010 to 4,486 mmcf in 2011. The increase in oil and natural gas sales volumes was primarily attributable to the effect of the acquisition of Maecenas Minerals LLP on March 31, 2010, activity in the Fayetteville Shale trend of Arkansas, and continued development activities on the Royalty Properties.

During the third quarter of 2011 oil and gas sales volumes attributable to our NPIs included for the first time volumes attributable to the Minerals NPI. The Minerals NPI had cumulative revenues exceed cumulative operating and development costs at September 30, 2011. Sales volumes and prices attributable to the Minerals NPI during periods prior to the third quarter of 2011 are excluded from the above table because DMLP did not receive any payments as a result of such NPI sales volumes during those prior periods. See “Overview” above.

Oil sales volumes attributable to our NPIs during the third quarter and first nine months of 2011 were 14 mbbls and 18 mbbls, respectively, an increase from 2 mbbls and 7mbbls during the same periods of 2010, respectively. Natural gas sales volumes attributable to our NPIs during the third quarter and first nine months of 2011 also increased from the same periods of 2010. Third quarter gas sales volumes of 990 mmcf during 2011 were 15.7% higher than 856 mmcf during 2010. First nine month sales volumes of 2,553 mmcf during 2011 were about the same compared to 2,526 mmcf during the same period of 2010. Natural gas and oil sales volume changes were a result of the inclusion of the Minerals NPI which partially offset natural reservoir decline.

The weighted average oil sales prices attributable to our interest in Royalty Properties increased 23.1% from $71.23/bbl during the third quarter of 2010 to $87.69/bbl during the third quarter of 2011 and increased 24.8% from $73.04/bbl during the first nine months of 2010 to $91.17/bbl during the same period of 2011. Third quarter weighted average natural gas sales prices from Royalty Properties decreased 4.1% from $4.11/mcf during 2010 to $3.94/mcf during 2011. The nine months ended September 30 weighted average Royalty Properties natural gas sales prices decreased 10.2% from $4.40/mcf during 2010 to $3.95/mcf during 2011. Both oil and natural gas price changes resulted from changing market conditions.

Third quarter weighted average oil sales prices from the NPIs increased 28.2% from $64.54/bbl in 2010 to $82.74/bbl in 2011. The first nine months NPIs’ oil sales prices increased 24.4% from $68.06/bbl in 2010 to $84.68/bbl in 2011. Changing market conditions resulted in increased oil prices. Third quarter weighted average natural gas sales prices attributable to the NPIs were about the same at $4.08/mcf in 2010 compared to $4.10/mcf in 2011. The first nine months ended September 30, 2011 natural gas prices decreased 6.9% to $4.19/mcf from $4.50/mcf in the same period of 2010. Natural gas sales price changes during the three- and nine-month periods resulted from changing market conditions.

Our third quarter net operating revenues increased 11.3% from $16,467,000 during 2010 to $18,326,000 during 2011. Net operating revenues for the first nine months of 2011 increased 6.0% from $46,262,000 during 2010 to $49,049,000 during 2011. Both the quarterly and nine-month increases resulted primarily from increased oil prices and oil and gas sales volumes discussed above.

Costs and expenses of $6,857,000 and $20,070,000 during the third quarter and nine months of 2011, respectively, were about the same as $6,950,000 and $19,895,000 during the same periods of 2010. The third quarter and nine-month 2011 decreases in depletion and amortization costs offset increased production tax on higher operating revenues in 2011.

Depletion and amortization costs were $4,817,000 and $13,640,000 during the third quarter and nine months ended September 30, 2011, respectively, compared to $5,068,000 and $13,842,000 during the same periods of 2010. Higher sales volumes during 2011 did not have a significant impact on the depletion calculation as upward reserve revisions at 2010 year-end along with the inclusion this quarter of Minerals NPI more than offset the increase in full cost basis related to the acquisition of Maecenas Minerals at March 31, 2010.

Third quarter net earnings allocable to common units increased 21.1% from $9,201,000 during 2010 to $11,139,000 during 2011. First nine months common unit net earnings increased 9.9% from $25,497,000 during 2010 to $28,030,000 during 2011. Both increases are primarily the result of increased oil prices and natural gas sales volumes as discussed above, partially offset by reduced lease bonus income.

Net cash provided by operating activities decreased 2.7% from $15,307,000 during the third quarter of 2010 to $14,892,000 during the third quarter of 2011 and was about the same at $42,892,000 for the first nine months of 2010 compared to $42,506,000 during the same period of 2011. Decreases in both periods are primarily due to decreased lease bonus income partially offset by increased oil and natural gas sales volumes.

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 2011 third quarter totaled approximately $13,300,000. These receipts generally reflect oil sales during June through August 2011 and natural gas sales during May through July 2011. The weighted average indicated prices for oil and natural gas sales during the 2011 third quarter attributable to the Royalty Properties were $91.68/bbl and $4.11/mcf, respectively.

Cash receipts attributable to our NPIs during the 2011 third quarter totaled approximately $2,100,000. These receipts reflect oil and natural gas sales from the properties underlying the NPIs generally during May through July 2011. The weighted average indicated prices received during the 2011 third quarter for oil and natural gas sales were $94.01/bbl and $4.38/mcf, respectively.

We received cash payments of approximately $235,000 from various sources during the third quarter of 2011 some attributable to 11 consummated leases and pooling elections located in eight counties and parishes in three states. The consummated leases reflected royalty terms ranging up to 25% and lease bonuses ranging up to $2,000/acre.

We received division orders for, or otherwise identified, 96 new wells completed on our Royalty Properties and NPIs located in 36 counties and parishes in six states during the third quarter of 2011. The operating partnership elected to participate during the quarter in 11 wells to be drilled on our NPI properties located in two counties in one state.

APPALACHIAN BASIN — We own varying undivided perpetual mineral interests in approximately 31,000/24,000 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, New York, an area which some industry press reports suggest may be prospective for gas production from unconventional reservoirs, including the Marcellus Shale. The New York State Department of Environmental Conservation has completed its regulatory review of high-volume hydraulic fracturing practices; however, development of these natural gas resources will be limited until remaining regulatory issues have been resolved. We continue to monitor industry activity and encourage dialogue with industry participants to determine the proper course of action regarding our interests in this area.

BARNETT SHALE -– We own varying undivided mineral and overriding royalty interests in approximately 1,820 acres located in Tarrant County, Texas in an area commonly referred to as the Core Area of the Barnett Shale Trend. As of September 30, 2011, 43 wells had been drilled, of which 41 wells were completed for production and two were drilled but not yet completed or connected to a pipeline. Permits to drill two additional wells on the properties had been issued by regulatory agencies. In the third quarter seven wells were brought on production with an average reported test rate of 3.4 mmcfd. DMLP owns a 17.1% NRI in these wells.

FAYETTEVILLE SHALE, 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. Three hundred forty-seven wells have been permitted on the lands as of Septembe 30, 2011, of which the operating partnership has an interest in 215. In total, 322 wells had been spud of which 283 had been completed as producers, 34 were in various stages of drilling or completion operations or waiting on a pipeline, and five wells had been abandoned. 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.

Set forth below is a summary of Fayetteville Shale activity through September 30, 2011 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI.

	2004 through 2007	2008	2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Total to Date
New Well Permits(1)	47	66	68	23	21	31	34	22	18	17	347
Wells Spud	41	62	70	22	15	28	23	20	23	18	322
Wells Completed(2)	27	54	49	13	32	18	25	29	17	16	280
Royalty Wells in Pay Status (3)	6	30	55	10	14	20	26	22	17	16	216

(1) Excludes permits that expire undrilled.
(2) Completing date defined as the day the well commences production.
(3) 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 $1,096,000 in the third quarter from 216 wells. Net cash receipts for the Minerals NPI Properties attributable to interests in these lands totaled approximately $710,000 in the third quarter from 115 wells.

HORIZONTAL BAKKEN, WILLISTON BASIN –- We own varying undivided perpetual mineral interests totaling 70,390/8,905 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, Marathon Oil Company, and Whiting Oil & Gas. There have been a total of 182 wells permitted on these lands as of September 30, 2011 with 126 completed as producers. In virtually all cases we have elected not to lease our lands and not to pay our share of well costs, thus becoming a non-consenting mineral owner. According to North Dakota law, non-consenting owners receive the average royalty rate from the date of first production and back-in for their full working interest after the operator has recovered 150% of drilling and completion costs. Once 150% payout occurs, the working interest will be owned by the operating partnership and 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. As of September 30, 2011, ten of these wells had achieved 150% payout.

Set forth below is a summary of Horizontal Bakken activity through September 30, 2011 for wells in which we have a royalty or Net Profits Interest. This includes wells subject to the Minerals NPI.

	2004 through 2007	2008	2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Total to Date
New Well Permits	17	44	23	7	16	13	22	11	16	13	182
Wells Spud	14	26	30	7	15	12	10	18	15	17	164
Wells Completed	9	22	31	9	6	13	10	8	12	6	126
Wells Reaching 150% Payout(1)	0	3	1	1	0	3	0	0	1	1	10

(1) Wells reaching 150% payout means wells for which the 150% risk penalty has been recovered during the indicated period.

Liquidity and Capital Resources

Capital Resources

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

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

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

Expenses and Capital Expenditures

The operating partnership plans to continue its efforts to increase production in Oklahoma with techniques that may include fracture treating, deepening, recompleting, and drilling. Costs 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 NPIs 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. These capital and operating costs are reflected in the NPI 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 NPIs. 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 $15,739,000 at September 30, 2011 and $11,253,000 at December 31, 2010.

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. The full cost ceiling is evaluated 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 or crude oil 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 the unweighted arithmetic average of the first day of the month price during the 12-month period ending on the balance sheet date 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 Royalty Properties and NPI 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 NPIs, which generally entitle us to receive a share of the proceeds based on oil and natural gas production from those properties. Consequently, we are subject to market risk from fluctuations in oil and natural gas prices. Pricing for oil and natural gas production has been volatile and unpredictable for several years. We do not anticipate entering into financial hedging activities intended to reduce our exposure to oil and natural gas price fluctuations.

Absence of Interest Rate and Currency Exchange Rate Risk

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

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Controls

There were no changes in our internal controls (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) during the quarter ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 6. EXHIBITS

See the attached Index to Exhibits.

SIGNATURES

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

DORCHESTER MINERALS, L.P.

By: Dorchester Minerals Management LP
its General Partner

By: Dorchester Minerals Management GP LLC
its General Partner

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

Date: November 2, 2011

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

Date: November 2, 2011

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 Limited Partnership Agreement 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)
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)
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith