UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **May 10, 2011**

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

Delaware	000-50175	81-0551518
(State or other jurisdiction of incorporation or organization	Commission File Number	(I.R.S. Employer Identification No.)

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

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

N/A
(Former name, former address and former fiscal year, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (See General Instruction A.2. below):

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure

On May 11, 2011, the Registrant will hold its 2011 Annual Meeting of Limited Partners. As the Chairman of the meeting, William Casey McManemin, the Chief Executive Officer of Dorchester Minerals, L.P., will discuss historical financial and operational information of Dorchester Minerals, L.P. The slide presentation Mr. McManemin will use in conjunction with his presentation is attached as Exhibit No. 99.1.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

99.1 Slide Presentation is attached hereto as Exhibit 99.1 and incorporated herein by reference.

Limitation on Incorporation by Reference

In accordance with general instructions B.2 and B.6 of Form 8-K, the information disclosed in this report under Item 7.01, including Exhibit 99.1, is being furnished and shall not be deemed "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section, and shall not be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended.

SIGNATURE

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.
Registrant

by Dorchester Minerals Management LP
its General Partner,
by Dorchester Minerals Management GP LLC
its General Partner

Date: May 10, 2011

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

Exhibit 99.1

Dorchester Minerals, LP
Annual Meeting

May 11, 2011

Forward-Looking Statements

Portions of this document may constitute "forward-looking statements" as defined by federal law. Such statements are subject to certain risks, uncertainties and assumptions. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated or projected. Examples of such uncertainties and risk factors 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 the Partnership’s properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and the Partnership’s consolidated financial position, business strategy and other plans and objectives for future operations. These and other factors are set forth in the Partnership's filings with the Securities and Exchange Commission.

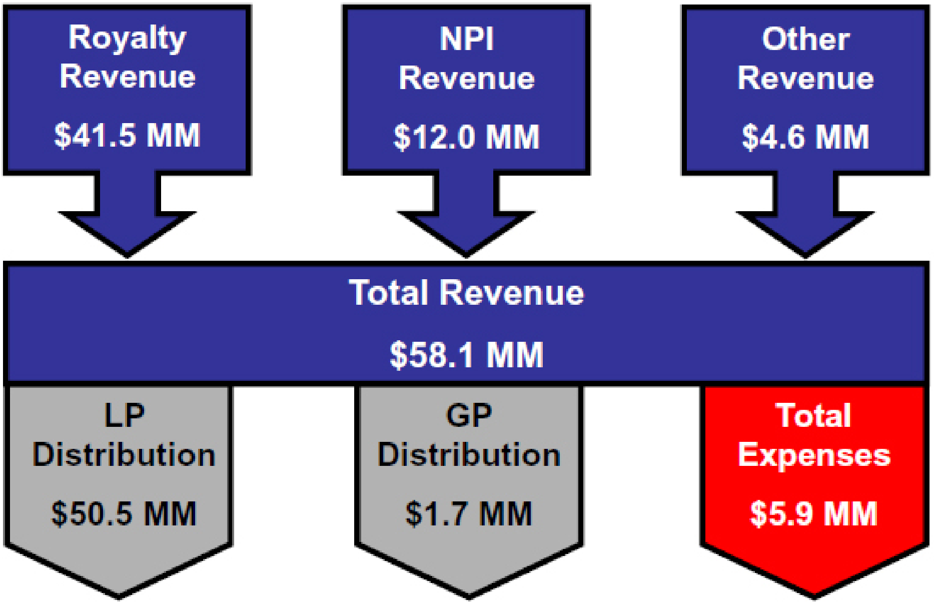
Presentation Outline

- Overview of 2010
  - Distributions and Financial Results
  - Production and Reserves
  - Peer Group Analysis
- Maecenas Minerals Acquisition
- Royalty Overview
- Net Profits Interest Overview
- Property Highlights
  - Barnett Shale
  - Hugoton Operations
  - Fayetteville Shale
  - Horizontal Bakken
  - Permian Basin
- Developing Plays

Overview of 2010 Results

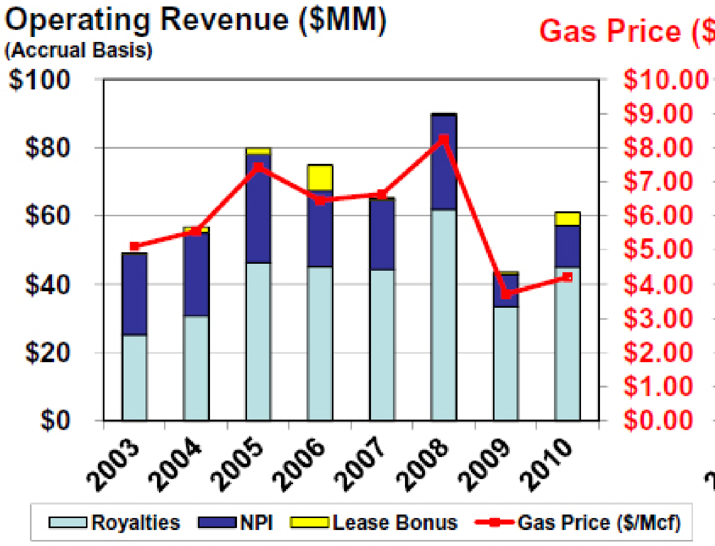
2010 Distributions

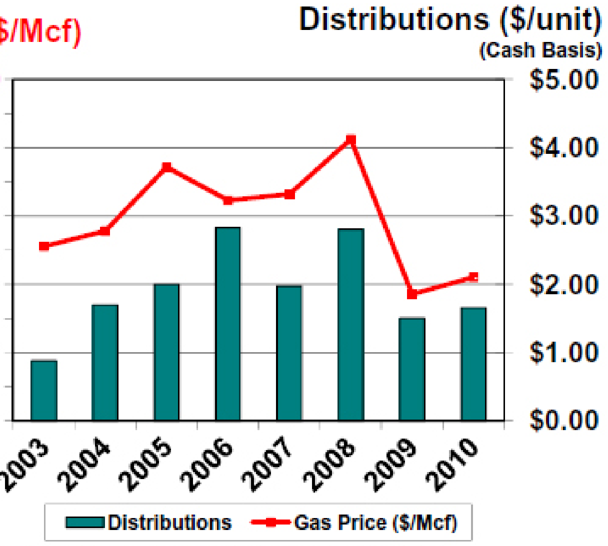
- Cash Distributions Paid in Calendar 2010
  - Reflects Q4 2009 to Q3 2010 activity



2010 Financial Results

- Revenue – Price – Distributions
  - Royalty properties contributed 74% to total operating revenues
  - Gross Revenue → 53% gas sales, 41% oil sales, 6% other revenue
  - NPI and lease bonuses have become a smaller portion of revenues



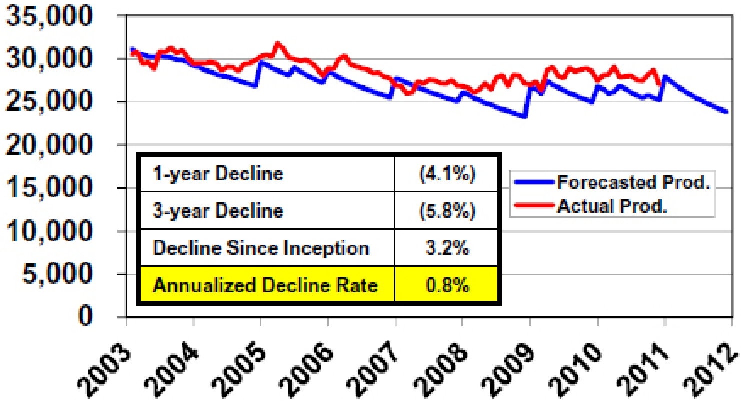


Note: Operating Revenue does not reflect production costs or other expenses incorporated in calculating the net profits interest payments

2010 Production Overview

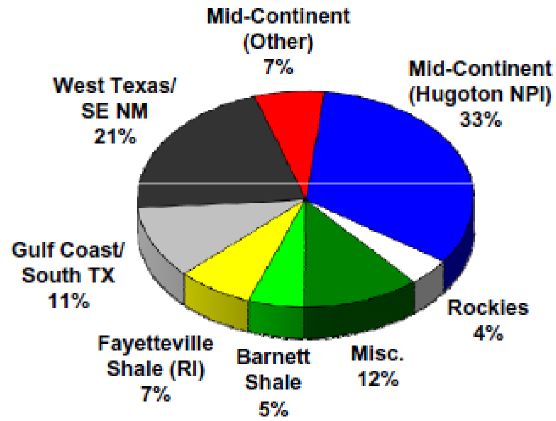
- Total Production of 10.75 Bcfe
  - 82% of total production was natural gas, 18% oil and condensate
  - High quality properties + Diverse portfolio → Low decline rate
  - Year-over-year production rate increased 4.1%

Production Profile



1-year Decline	(4.1%)
3-year Decline	(5.8%)
Decline Since Inception	3.2%
Annualized Decline Rate	0.8%

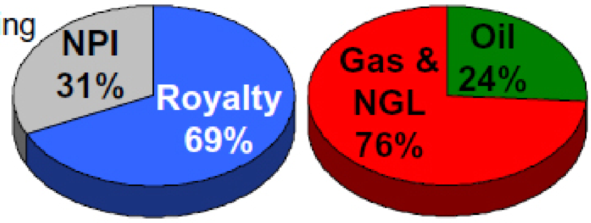
Geographic Breakdown



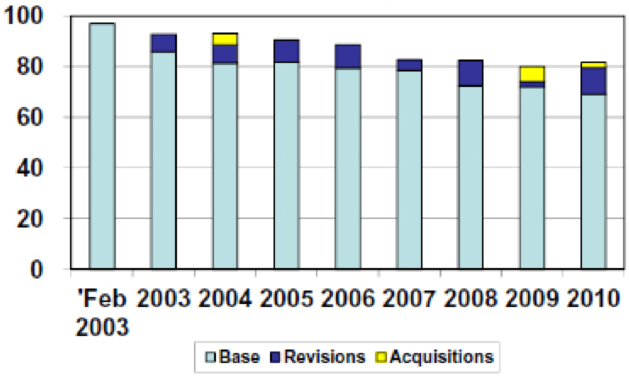
Note: Total production on wellhead basis, daily production on sales basis, gas-oil equivalency based on 6:1 ratio

2010 Reserves Overview

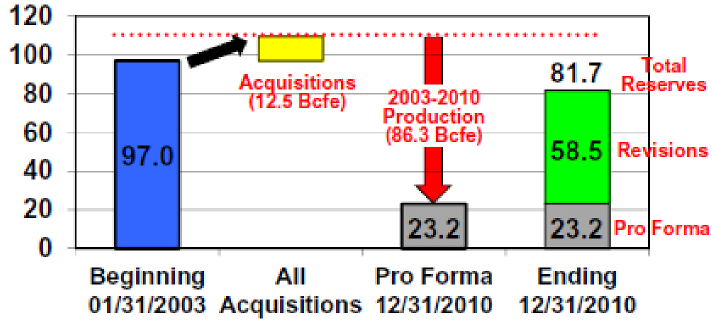
- Total Proved Reserves of 81.7 Bcfe on 12/31/10
  - All reserves are Proved Developed Producing
  - Demonstrated history of positive revisions
  - Revisions accounted for 72% of total reserves at 12/31/2010
  - Driven by new plays, field extensions, infill drilling, new technology, etc.
  - Fayetteville Shale (RI only) represents 5% of reserves



Year-end Reserves (Bcfe)



Cumulative Reserve Revisions (Bcfe)

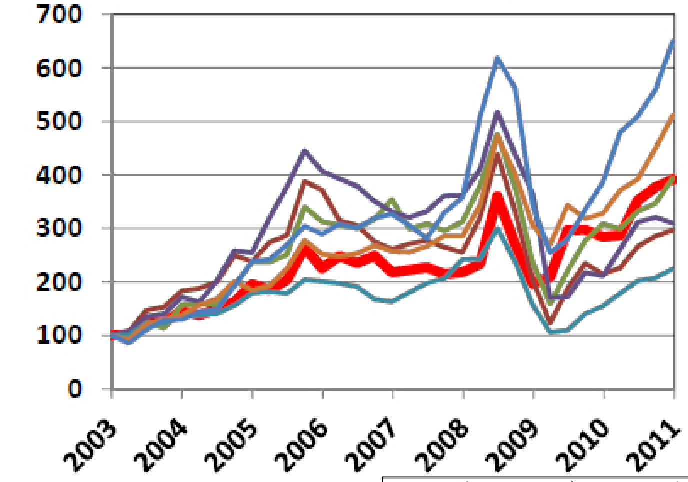


Note: 12.5 Bcfe of acquired reserves at time transactions closed.

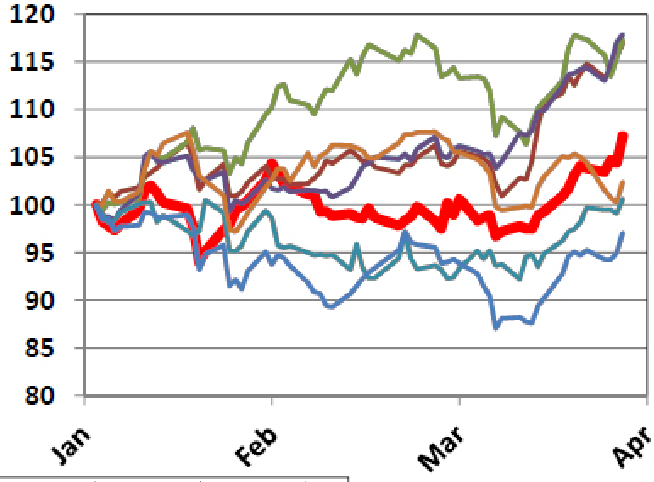
Peer Group Comparison

- Market Performance
  - Pure royalties lack operating leverage inherent in net profits interests → Less volatility
    - Underperforming in high price environment (mid-2008)
    - Outperforming in low price environment (mid-2009) due to lower fixed cost structure

2003-2010 Normalized Returns (reinvested)



YTD 2011 Normalized Returns (reinvested)

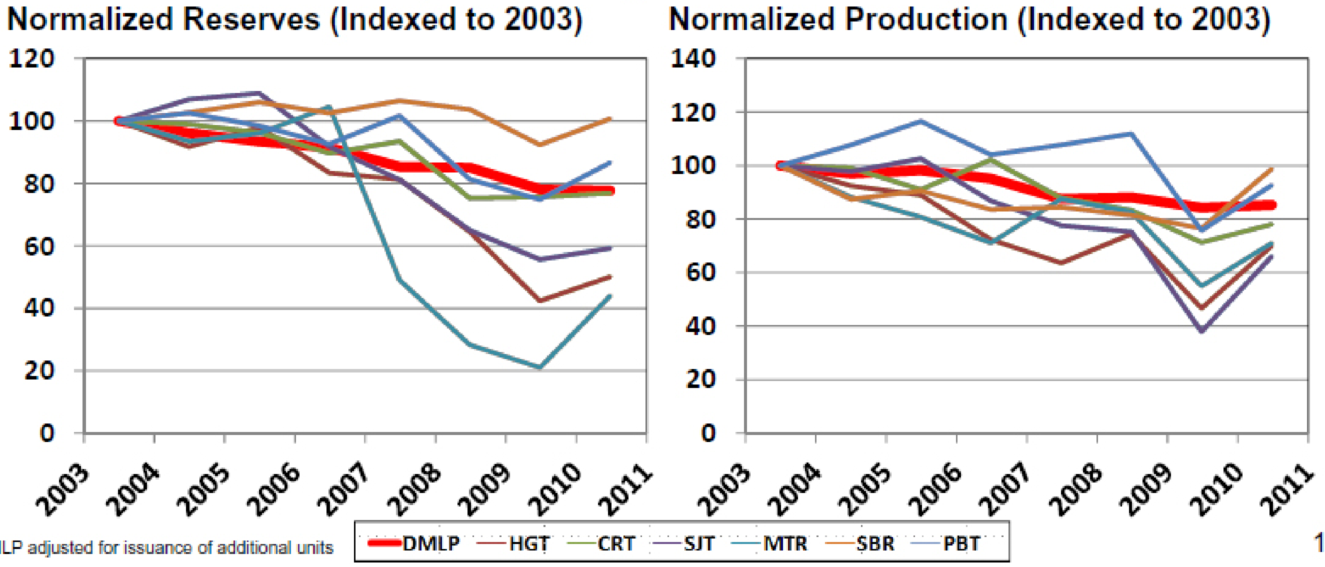


Note: Dist. reinvested on last day of quarter

DMLP HGT CRT SJT MTR SBR PBT

Peer Group Comparison

- Reserves and Production Performance
  - DMLP is a cross between a royalty trust with 100% net profits interests (SJT) and one with 100% royalties (SBR), plus the upside of a large non-producing mineral portfolio with potential for future drilling and development
  - DMLP has the ability to expand its portfolio of assets through acquisitions



DMLP adjusted for issuance of additional units

Maecenas Minerals Acquisition

Maecenas Minerals Acquisition

- Minerals and Royalties – 206 counties in 17 states
  - Transaction closed on 03/31/10 as a non-taxable exchange for 835,000 units
  - Assets concentrated in Texas and North Dakota with increased exposure to oil plays
    - Permian Basin → Seminole (San Andres), Goldsmith, Wolfberry potential
    - Williston Basin → Cedar Hills South Unit, Bakken and Three Forks/Sanish potential
  - DMLP already owns interests in all acquired properties
  - Simple integration into existing accounting and land systems
  - Portfolio includes significant undeveloped acreage with upside potential
  - First year results:

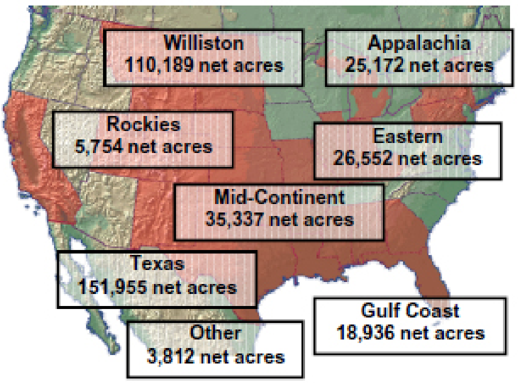
	Units	Cash to LP	Cash per Unit	Accretion
DMLP (stand-alone)	29,840,431	$50.08 MM	$1.678	
Maecenas Minerals	835,000	$1.66 MM	$1.988	18.5%

Note: Cash to LP based on distributions declared in 2010.

Royalty Overview

Royalty Overview

- Diverse Portfolio – 574 counties in 25 states
  - 377,707 net mineral acres (2,308,024 gross acres)
  - Varying NPRI's, ORRI's and leasehold interests in 861,823 gross acres
  - Majority of acreage is undeveloped
  - Wide geographic spread including most major producing basins
  - Assets range from mature legacy production to areas with exploratory potential



Basin/Area	Legacy Production	Ongoing Development	Expansion Potential
West Texas Southeast NM	Denver Unit Wasson	Wolfberry	Delaware Basin West TX Overthrust
Gulf Coast South Texas	Jeffress McAllen Ranch	Bob West	Horizontal Wilcox
Mid-Continent	Hugoton	Fayetteville	Horizontal Granite Wash
Williston Basin	Nesson Anticline	Bakken Red River	Three Forks Sanish
Appalachia			Marcellus/Utica Upper Devonian

Note: Acreage count as of 12/31/2010, includes Maecenas transaction. Gross acres are not additive due to overlapping ownership among categories

Royalty Overview

- Leasing and Development Activity
  - Consummated 103 leases/elections on 2,288 net acres in 32 counties/ parishes in eight states
  - Lease bonus payments up to $5,010/acre
  - Initial royalty terms up to 26%
  - 121 active lease offers as of May 2011
  - Identified 348 new wells on royalty properties in 10 states
  - Fayetteville Shale activity continued to ramp up in 2010
  - Low gas price environment → reduced infill drilling and redevelopment on legacy gas properties, opposite is true for oil.

Net Profits Interests Overview

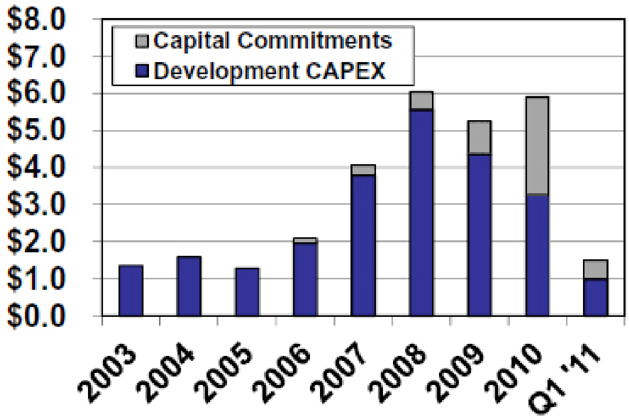
Net Profits Interests Overview

- NPI Provides LP Exposure to Working Interest Potential Without Generating UBTI
  - Four NPI groups were created at the time of formation in 2003 and two additional NPI groups created subsequently
  - Capitalize on strong negotiating position to capture additional value
  - Leverage information franchise
  - Optional working interest participation in numerous leases
  - Minerals NPI represents the majority of new development activity
  - Added 85 new wells located in Arkansas, Louisiana, Mississippi, North Dakota, Oklahoma and Texas
    - 57 wells completed in 2010
    - 20 wells in various stages of drilling or completion at year-end 2010
    - 8 wells completed in prior years (APO back-in interests)

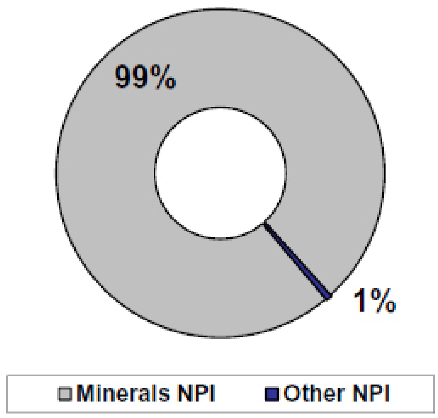
Net Profits Interests Overview

- Actual Capital Expenditures Through Year-end 2010
  - $27.6 million of cumulative investments in all net profits interest properties
  - Majority of CAPEX was used to drill new wells in the Minerals NPI
  - Continue to reinvest Minerals NPI cash flow

Historical NPI CAPEX ($MM)



2010 NPI CAPEX

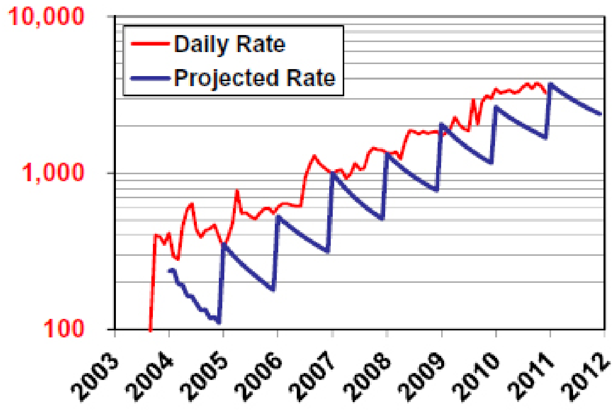


Note: CAPEX incurred by the operating partnership on a cash basis. Capital commitments are included in calculating the Minerals NPI payout status.

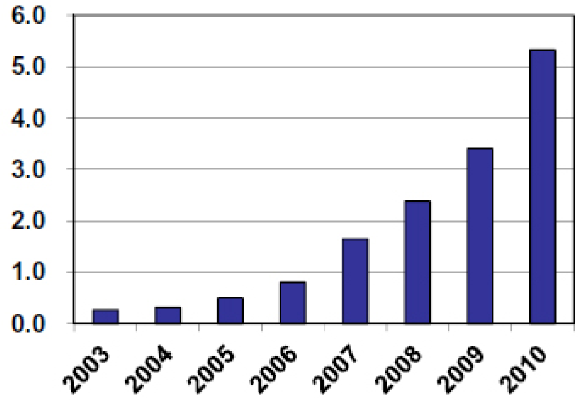
Net Profits Interests Overview

- Minerals NPI Performance
  - Production and reserves growing steadily since inception
  - 261 wells/units producing in Q4 2010 (215 in pay status)
  - 3.9 Bcfe in production receipts through year-end 2010
  - Total proved reserves of 5.3 Bcfe at year-end 2010, a 56% increase over 2009
  - Minerals NPI production and reserves are not included in DMLP results

Net Daily Gas Rate (Mcfd)



Proved Reserves (Bcfe)



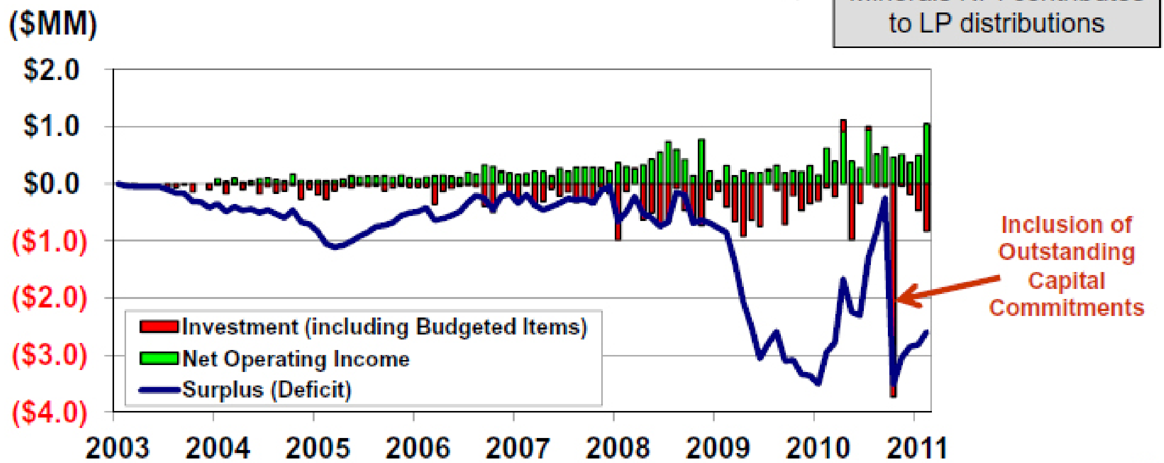
Note: Gas rate based on sales volumes

Net Profits Interests Overview

- Minerals NPI Cash Flow – Inception through Q1 2011

Cumulative Revenue	$27.9 MM
Cumulative Expense (LOE, taxes, etc)	($5.2 MM)
Cumulative Operating Income	$22.7 MM
Cumulative Investment/Commitments	($25.3 MM)
Cumulative Surplus (Deficit)	($2.6 MM)

Surplus balance must be positive before the Minerals NPI contributes to LP distributions



Note: Figures provide on a cash basis

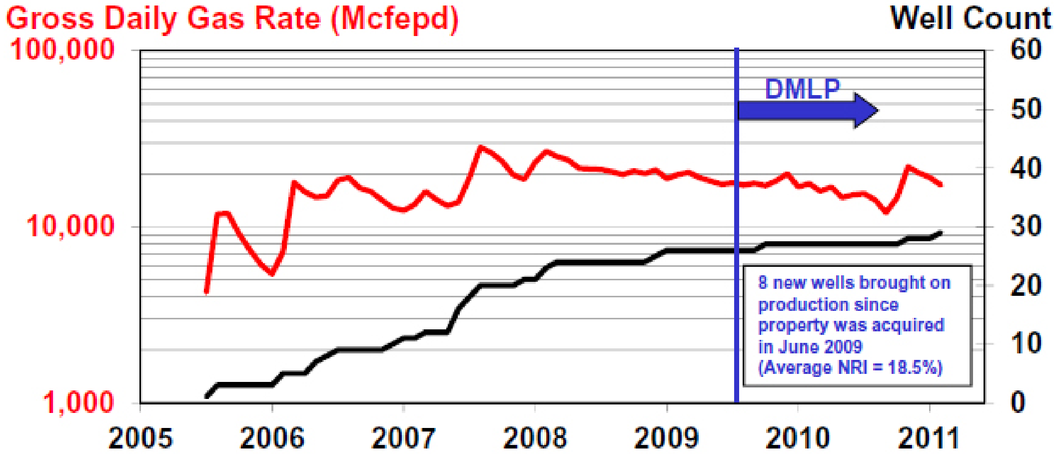
Property Highlights

Barnett Shale

Barnett Shale (Royalty)

- Fort Worth Basin – Tarrant County, Texas
  - NRIs range from 0.5% to 20% in 1,824 net mineral acres
  - Current Development Activity (CHK Operated)
    - 34 producing wells (5 currently S/I)
    - 7 wells waiting on completion or pipeline
    - 4 permitted locations

    45 wells/permits
  - Upside potential in undeveloped acreage, downspacing and improved stimulation

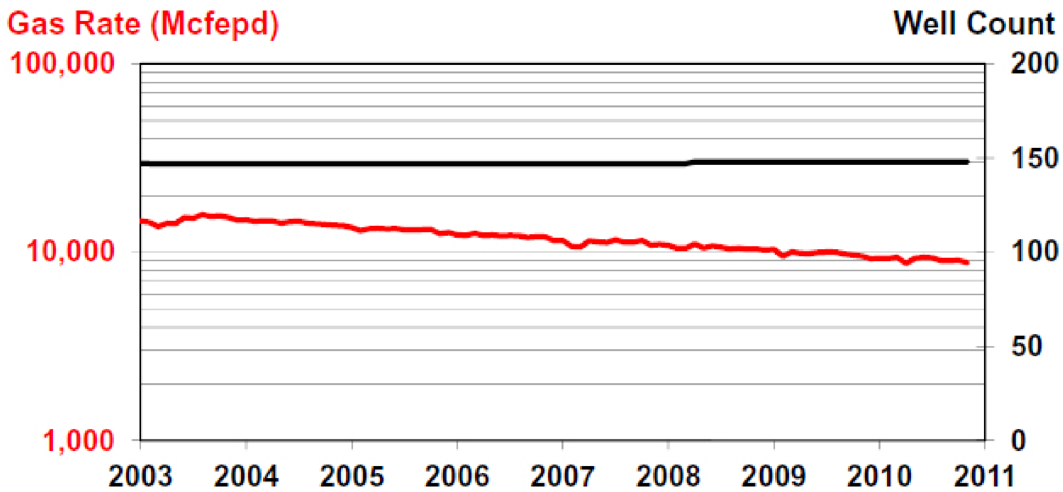


Property Highlights

Hugoton Operated Properties

Hugoton Operated Properties (NPI)

- Hugoton Field – Oklahoma Panhandle & SW Kansas
  - 2010 production within 3% of projection
  - Year-over-year production decline of 7.6% with a 3% decrease in net reserves
  - World-class asset but limited upside potential
  - Ongoing well optimization and cost-saving initiatives



Note: Gas rate based on sales volumes

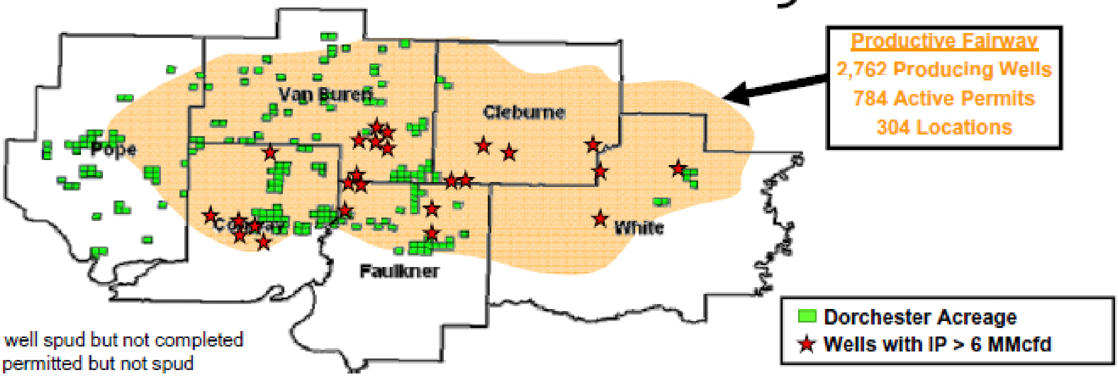
Property Highlights

Fayetteville Shale

Fayetteville Shale (Royalty & NPI)

- Eastern Arkoma Basin – Northern Arkansas
  - Ownership Summary
    - 23,336 gross/11,464 net acres in 196 sections
    - Leased 9,800 net acres in 179 sections for 25% royalty with optional participation in 111 sections (subject to Minerals NPI)
    - Tracts not HBP will expire in Q2 2011 (drilling or permitting activity on 53% of sections)
  - Current development activity on DMLP acreage
    - 247 wells completed (205 in pay status)
    - 24 wells in various stages of drilling, completion or WOPL
    - 44 wells permitted and/or proposed by operator

  315 wells/permits

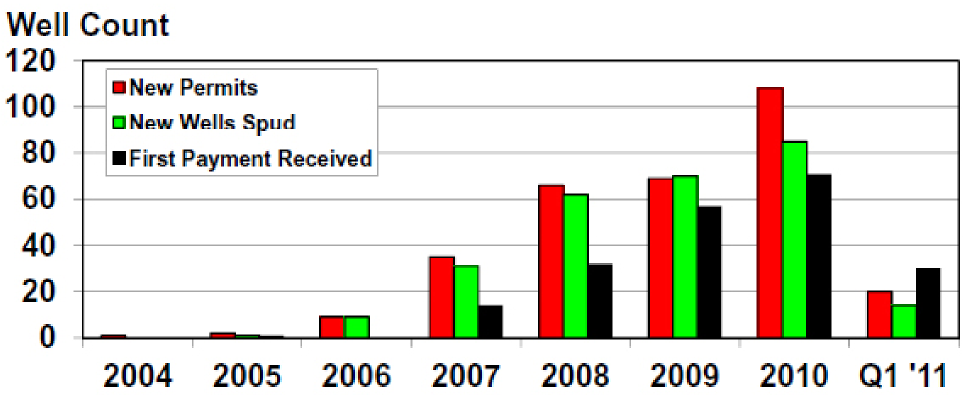


"Active Permit" – well spud but not completed
"Location" – well permitted but not spud

Fayetteville Shale (Royalty & NPI)

- Permitting, Drilling and Payment History
  - Development activity remains at high levels, driven by SWN, CHK (BHP), XTO (XOM)
  - Well spuds have been outpaced by well permits, a leading indicator
  - Substantial time-lag between permit and first payment → 373 days

Well Permitted → 54 days → Well Spud → 133 days → First Production → 186 days → First Payment

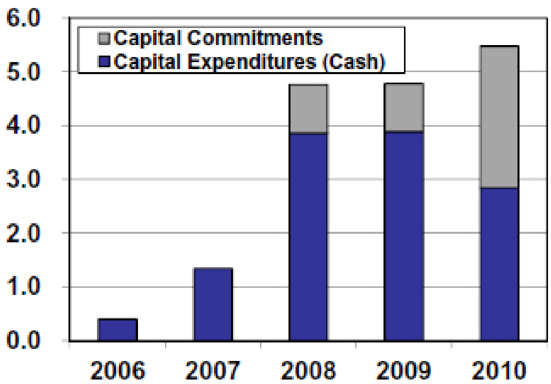


Fayetteville Shale (Royalty & NPI)

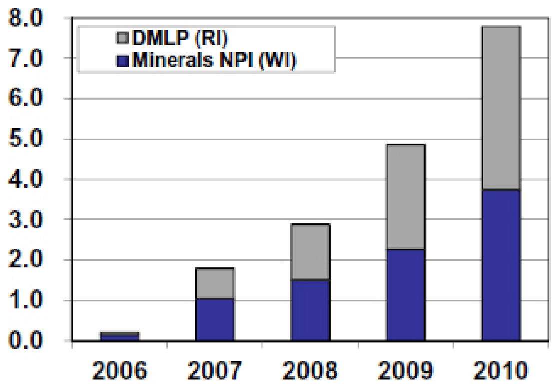
- Capital Expenditures
  - Total Fayetteville investments of $18.0 MM through Q1 2011
  - All expenditures within Minerals NPI
  - Average $3.1 MM per well in 2010
  - Drilling and completion costs may increase with longer lateral lengths

- 2010 Reserves
  - Year-end reserves of 7.7 Bcf (207 wells)
    - 3.7 Bcf (WI)
    - 4.0 Bcf (RI)
  - 57% Year-over-year reserve increase
  - Only completed wells with test rates are included in reserve estimates (no PUDs)

Capital Expenditures ($MM)



Proved Reserves (Bcf)

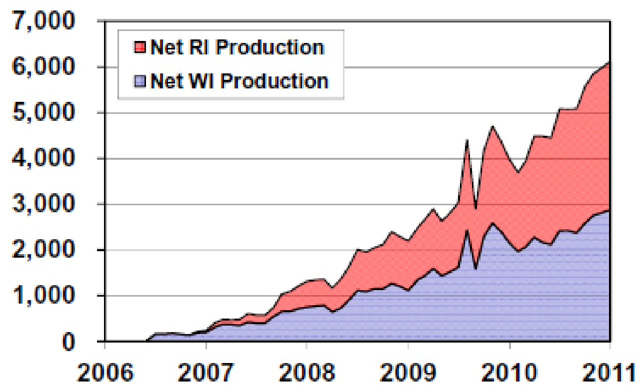


Fayetteville Shale (Royalty & NPI)

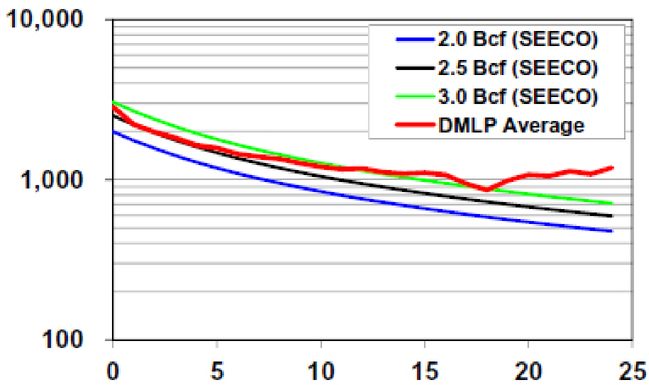
- Production Results
  - 207 wells producing at year-end 2010
    - 3.2 MMcfd (WI)
    - 2.9 MMcfd (RI)
    - } 6.1 MMcfd
  - 39% Year-over-year rate increase
  - Produced 1.8 Bcf in 2010
  - 48% of production from working interest

- Well Performance
  - Improved stimulation and longer laterals have increased initial production rates
    - 2007 1.7 MMcfd (Max 3.5 MMcfd)
    - 2008 2.4 MMcfd (Max 5.5 MMcfd)
    - 2009 3.1 MMcfd (Max 5.9 MMcfd)
    - 2010 3.0 MMcfd (Max 7.3 MMcfd)

Net Daily Production (Mcfd)



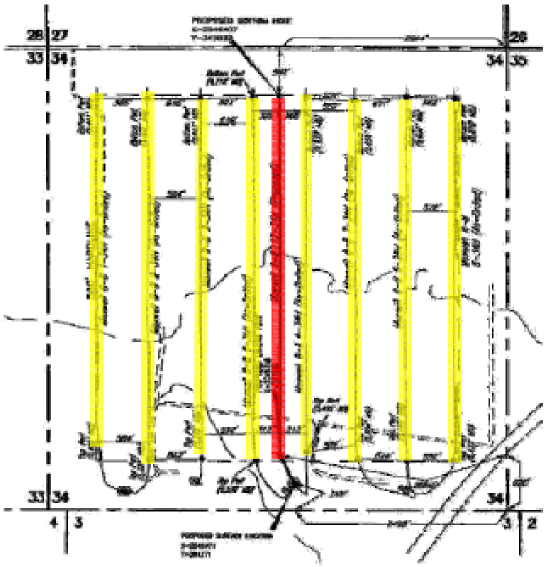
Normalized Production Rate (Mcfd)



Note: Volumes from AOGC, 1st point on DMLP normalize curve based on estimates from partial month data

Fayetteville Shale (Royalty & NPI)

- Future Development Potential - Downspacing
  - Example: 34-8N-8W White Co, AR (CHK) → No DMLP ownership



- *"…Approximately 30% of the roughly 600,000 net acres drilled to date can be developed at 30-to-50 acre spacing and approximately 70% can be developed at a maximum of 65 acre spacing."*

  -SWN Conference call (04/29/11)

Initial 80 acre spacing wells
Recent 40 acre spacing well

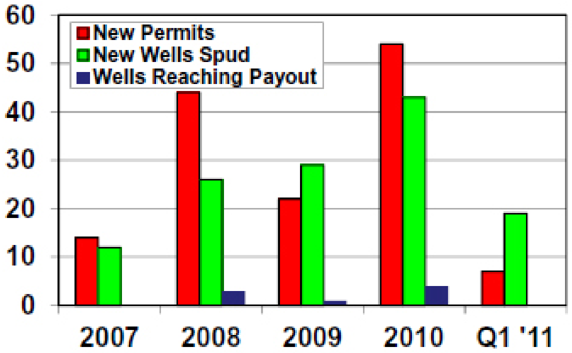
Property Highlights

Horizontal Bakken

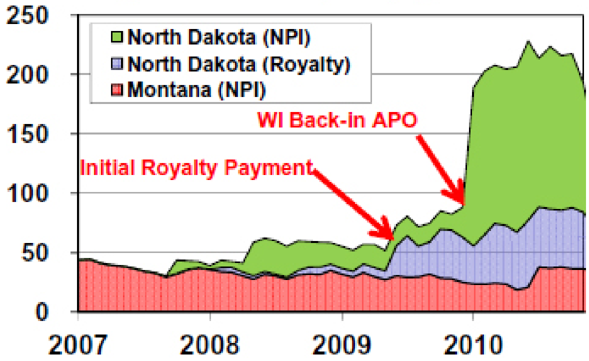
Horizontal Bakken (Royalty & NPI)

- Williston Basin – Northwestern North Dakota
  - Diversified acreage position
    - 70,390 gross acres/8,905 net acres
  - Operators: Continental, COP, EOG, Hess, Marathon
  - Elected non-consent option in 150 wells to date
    - Average royalty of all leases in unit (~16% royalty)
    - Back-in for 100% WI after payout + 50% penalty
    - Working interest subject to Minerals NPI

Well Count



Net Daily Production (boepd)

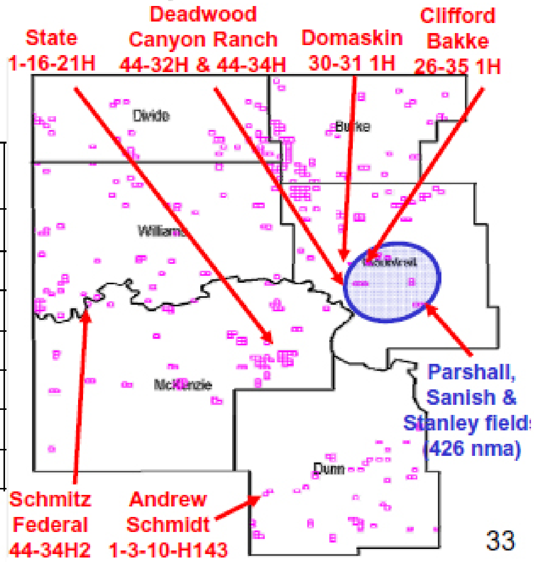


Horizontal Bakken (Royalty & NPI)

- Six County Core Area
  - Current development activity on DMLP acreage
    - 100 wells completed as producers (8 reached payout status)
    - 30 wells in various stages of drilling or completion (or confidential)
    - 19 wells permitted and/or proposed by operator

    149 wells/permits
  - Rig count has increased +450% since May 2009
  - Seven rigs currently drilling on DMLP acreage

Well Name (Operator)	Test Rate (boepd)	BPO NRI	APO NRI
Clifford Bakke 26-35 1H (BEXP)	5,060	1.10%	4.94%
Domaskin 30-31 1H (BEXP)	4,675	1.04%	5.94%
State 1-16-21H (Helis)	3,142	0.33%	2.06%
Schmitz Federal 44-34H2 (Oasis)	1,906	1.89%	7.67%
Deadwood Canyon Ranch 44-32H (Fidelity)	1,022	1.00%	4.94%
Deadwood Canyon Ranch 44-34H (Fidelity)	1,103	2.01%	9.88%
Andrew Schmidt 1-3-10-H143 (Anschutz)	1,049	0.47%	2.91%

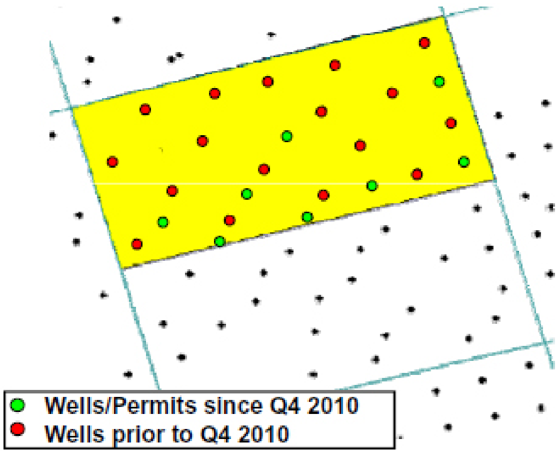


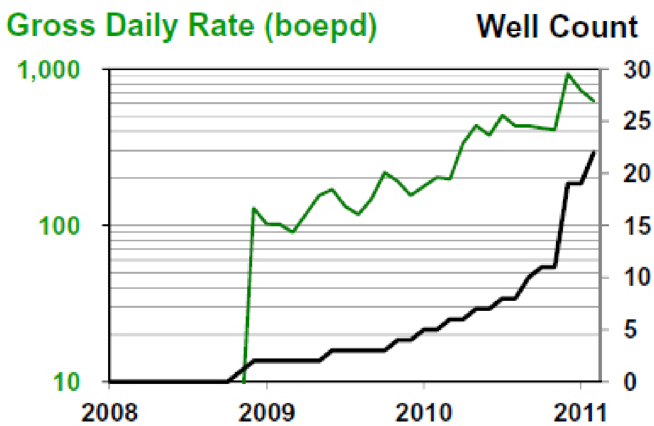
Property Highlights

Permian Basin

Permian Basin (NPI)

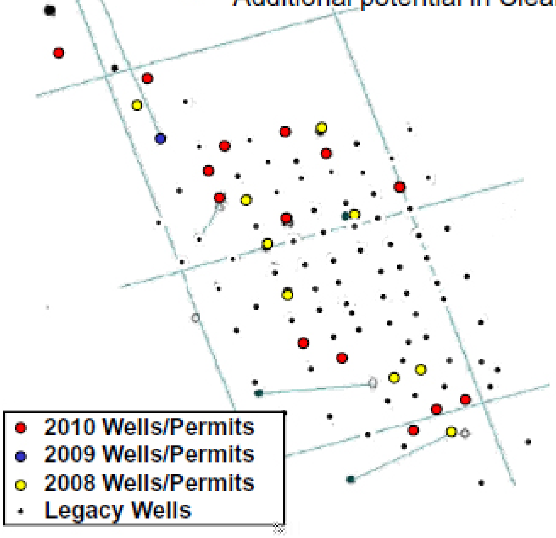
- Goldsmith Field – Ector County, Texas
  - CVX "6" Lease, Sandridge E&P → DMLP owns an 18.75% interest in 320 acres
    - Unleased MI→ No royalty, back-in for full 18.75% WI after payout (Minerals NPI)
    - 21 wells producing, 1 well waiting on completion, 3 wells permitted but not spud
    - Initial test rates range up to 277 boepd → 10 wells have reached payout as of Q1 2011

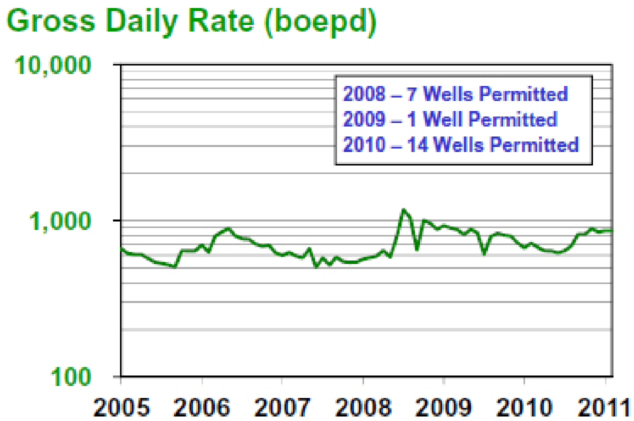




Permian Basin (Royalty)

- Keystone South Field – Winkler County, Texas
  - DMLP owns a royalty interest in the Keystone Cattle Company Lease
  - Active development drilling on a legacy property → 14 new wells permitted in 2010
  - Recent test rates range up to 116 boepd per well
  - DMLP has received lease offers on thousands of acres throughout the Permian Basin
    - Additional potential in Clearfork, Bone Springs, San Andres, and Wolfberry plays

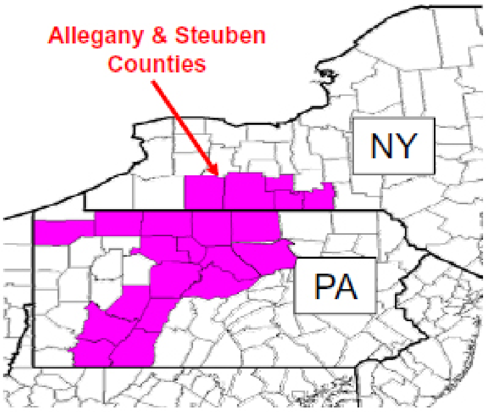




Developing Plays

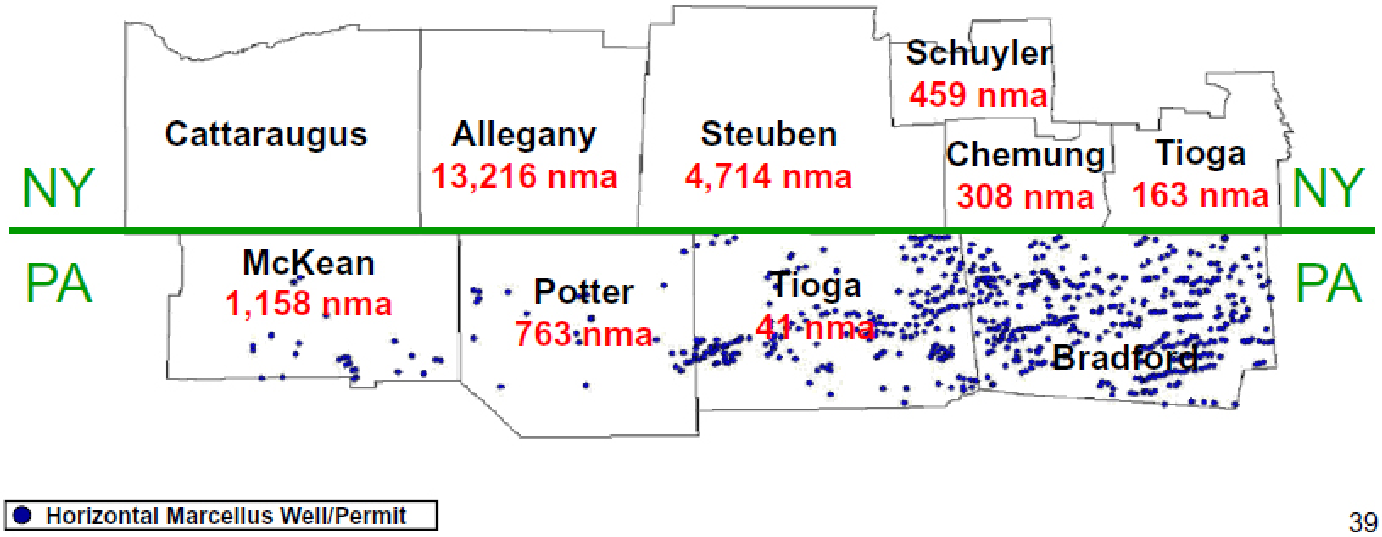
Developing Plays

- Devonian Shale – Appalachia
  - New York and Pennsylvania
  - Concentrated acreage position
    - 32,395 gross acres
    - 24,494 net acres
    - 70% in Allegany and Steuben Counties, NY
  - Challenging political environment in New York
  - Potential targets
    - Upper Devonian oil (shallow)
    - Marcellus/Utica/Devonian shale gas (middle)
    - Trenton-Black River gas (deep)
  - Operators: Anadarko, Chesapeake, EOG, EQT, EXCO, Range, Seneca, Shell, Talisman
  - No reserves booked in 2010



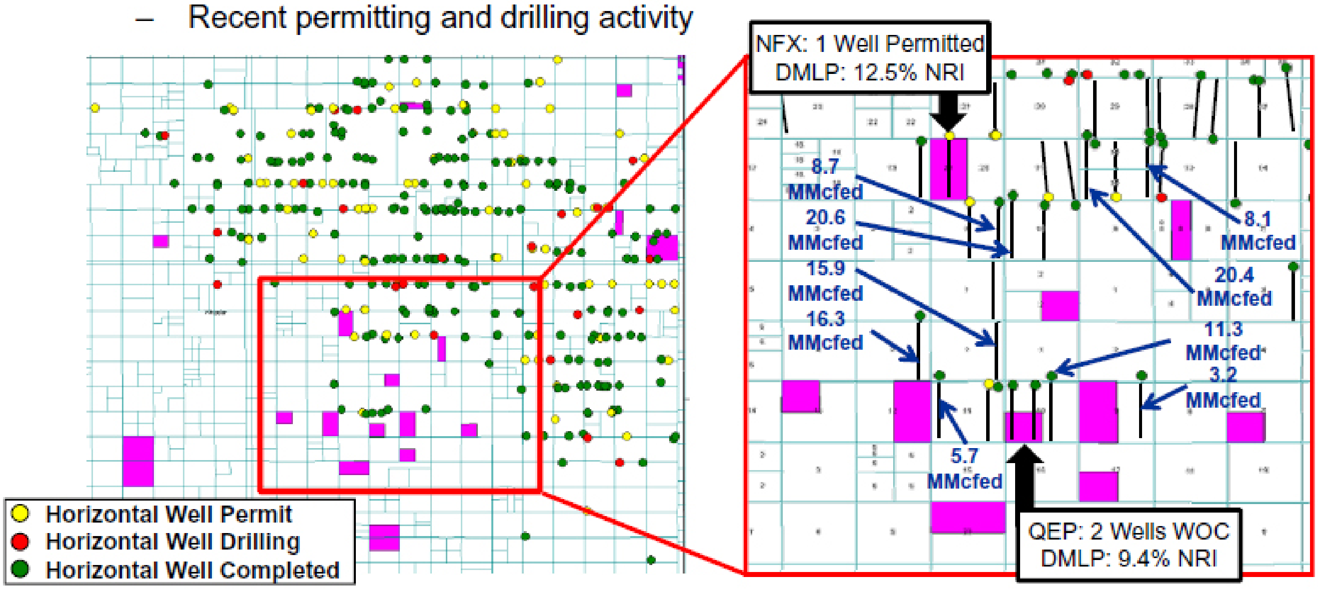
Developing Plays

- Southern Tier NY & Northern Tier PA
  - Regulatory environment in New York has limited activity relative to Pennsylvania
  - Prospectivity of acreage in Allegany and Steuben Counties is undetermined due to limited testing of potential shale gas zones
  - Continuing to monitor industry and regulatory activity in the area



Developing Plays

- Granite Wash – Texas Panhandle
  - Concentrated acreage position in Northeast Wheeler County
    - DMLP owns 5,444 gross/1,189 net acres
  - Substantial liquids component to production
  - Recent permitting and drilling activity



Appendix

Appendix

- What is the Minerals NPI and How Does it Work?

– Upon its formation, Dorchester Minerals, LP (DMLP, the public partnership and owner of the mineral interests) provided for future development opportunities on its undeveloped mineral interests by the creation of the Minerals Net Profits Interest (Minerals NPI).

– DMLP has negotiated and may continue to negotiate the right but not the obligation to participate in development activity in addition to retaining a royalty interest.

– This right may take the form of an optional heads-up (unpromoted) working interest, carried working interest or reversionary (back-in) working interest. In some instances, an unleased mineral interest may be treated as a working interest subject to statutory non-consent provisions.

– DMLP assigns this right to Dorchester Minerals Operating LP (the operating partnership or DMOLP) subject to the terms of the Minerals NPI.

– DMOLP is an indirect wholly owned affiliate of DMLP's General Partner.

– DMOLP funds all costs associated with this right, including drilling and completion costs.

– DMLP and its partners are not liable for any costs or expenses.

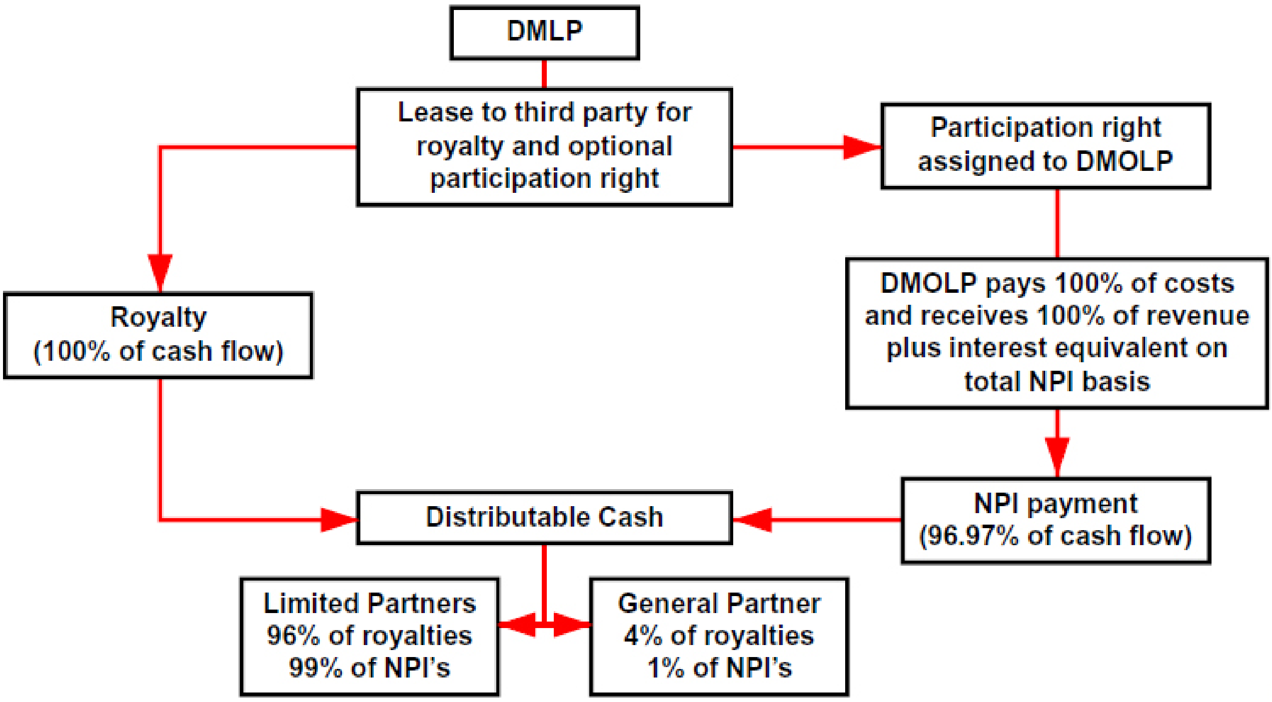
– DMOLP pays to DMLP 96.97% of the monthly "Net Proceeds" attributable to the properties subject to the Minerals NPI.

– Net Proceeds is defined as total revenues less total expenses plus an amount equivalent to interest at a prevailing rate on any prior period deficit balance. In other words, DMOLP pays 100% of all costs, receives 100% of all revenues plus interest, and thereafter (sometimes called "Payout") pays 96.97% of net cashflow to DMLP.

– LP distributions reflect 96% of royalty net cashflow and 99% of NPI net cashflow → 99% x 96.97% = 96%.

Appendix

- What is the Minerals NPI and How Does it Work?



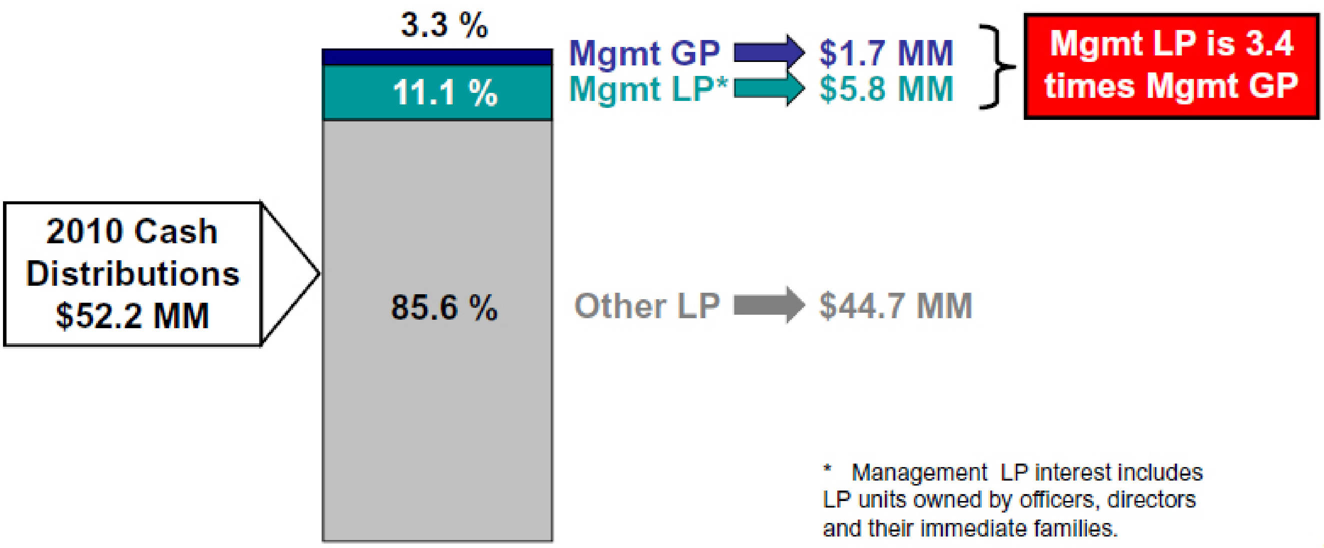
Appendix

- Distribution Determinations
  - Period from October 2009 through September 2010

	($ thousands) Limited Partners	General Partner
4% of Net Cash Receipts from Royalty Properties	$ --------	$1,608
96% of Net Cash Receipts from Royalty Properties	$38,605	$ --------
1% of Net Profits Interests Paid to our Partnership	$ --------	$ 120
99% of Net Profits Interests Paid to our Partnership	$11,865	$ --------
Total Distributions	**$50,470**	$1,728
Operating Partnership Share (3.03% of Net Proceeds)	$ --------	$ 374
Total General Partner Share		**$2,102**
% Total	**96%**	**4%**

Appendix

- Alignment of GP and LP interests
  - GP has no incentive distribution rights – fixed sharing ratio
  - Management's LP interest exceeds its GP interest
  - Not incentivized to make dilutive transactions



* Management LP interest includes LP units owned by officers, directors and their immediate families.

Appendix

- Operating Leverage – Royalty Interest vs. NPI

	Royalty Interest	Net Profits Interest
Production Volume	1,000 Mcf	1,000 Mcf
Gas Price	$4.00/Mcf	$4.00/Mcf
Revenue	$4,000	$4,000
Fixed Production Costs	($0)	($1,000)
Operating Income	$4,000	$3,000
Net Interest	25% Royalty	25% NPI
Net Cash Flow	$1,000	$750

25% Increase in Gas Price

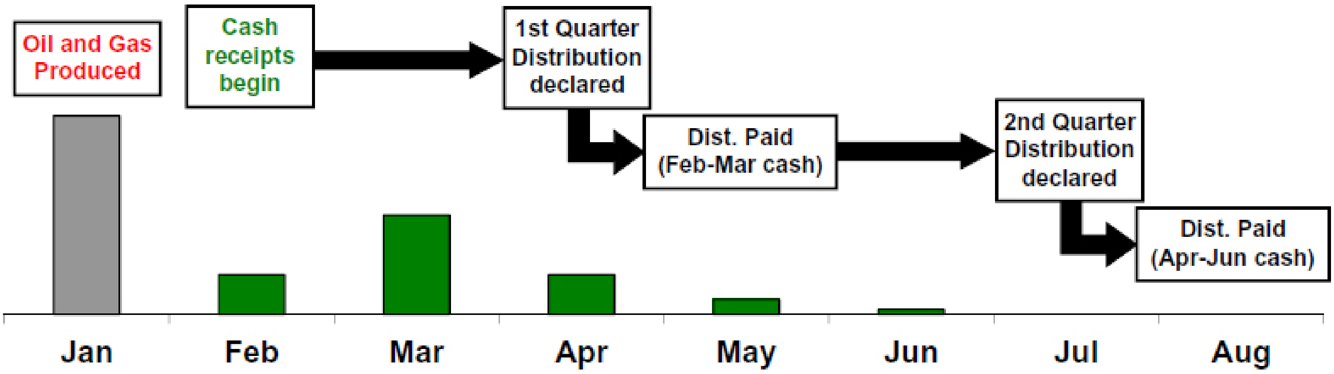
	Royalty Interest	Net Profits Interest
Production Volume	1,000 Mcf	1,000 Mcf
Gas Price	$5.00/Mcf	$5.00/Mcf
Revenue	$5,000	$5,000
Fixed Production Costs	($0)	($1,000)
Operating Income	$5,000	$4,000
Net Interest	25% Royalty	25% NPI
Net Cash Flow	$1,250	$1,000

25% Increase in Royalty Cash Flow

33% Increase in NPI Cash Flow

Appendix

- Royalty Cash Receipts
  - Long delay between production and cash distribution
  - Cash receipts extend over multiple months due to adjustments, releases, etc.
  - Prices can change dramatically between production and payment of distribution
  - Example of a typical cash receipt cycle :



LP distribution of all cash attributable to January production may occur as late as August, a 7-month time lag