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) November 12, 2012

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas	**001-35410**	**27-4662601**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

5400 LBJ Freeway, Suite 1500, Dallas, Texas	**75240**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (972) 371-5200

Not Applicable
(Former name or former address, 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:

☐ 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 2.02 Results of Operations and Financial Condition.

Attached hereto as Exhibit 99.1 is a press release (the “Press Release”) issued by Matador Resources Company (the “Company”) on November 12, 2012, announcing its financial results for the three month and nine month periods ended September 30, 2012. The Press Release is incorporated by reference into this Item 2.02, and the foregoing description of the Press Release is qualified in its entirety by reference to this exhibit. On November 12, 2012, the Company held a conference call and webcast with respect to its financial results for the three and nine month periods ended September 30, 2012. The conference call transcript (the “Transcript”), including the related question and answer session, is furnished as Exhibit 99.2 and incorporated herein by reference.

As previously announced, Mr. Foran will present at the Stephens Fall Investment Conference 2012 in New York City on Tuesday, November 13, 2012. The Company has updated its investor presentation (the “Investor Presentation”) for this conference and other presentations to potential investors to include the results of operations for the third quarter of 2012. A copy of the Investor Presentation is furnished as Exhibit 99.3 hereto and incorporated herein by reference.

The information furnished pursuant to this Item 2.02, including Exhibits 99.1, 99.2 and 99.3, shall not be deemed to be “filed” for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended (the “Securities Act”), unless specifically identified therein as being incorporated therein by reference.

In the Press Release, the Transcript and the Investor Presentation, the Company has included as “non-GAAP financial measures,” as defined in Item 10 of Regulation S-K of the Exchange Act, (i) earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock unit expense and net gain or loss on asset sales and inventory impairment (“Adjusted EBITDA”) and (ii) present value discounted at 10% (pre-tax) of estimated total proved reserves (“PV-10”). In the Press Release and the Investor Presentation, the Company has provided reconciliations of the non-GAAP financial measures to the most directly comparable financial measures calculated and presented in accordance with generally-accepted accounting principles (“GAAP”) in the United States. In addition, in the Press Release and the Investor Presentation, the Company has provided the reasons why the Company believes those non-GAAP financial measures provide useful information to investors.

Item 7.01 Regulation FD Disclosure.

Item 2.02 above is incorporated herein by reference.

The information furnished pursuant to this Item 7.01, including Exhibits 99.1, 99.2 and 99.3, shall not be deemed to be “filed” for the purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any filing under the Securities Act unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description of Exhibit
99.1	Press Release, dated November 12, 2012.
99.2	Transcript of Conference Call, dated November 12, 2012.
99.3	Presentation Materials.

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 hereunto duly authorized.

MATADOR RESOURCES COMPANY

Date: November 12, 2012

By: /s/ David E. Lancaster
Name: David E. Lancaster
Title: Executive Vice President

Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Press Release, dated November 12, 2012.
99.2	Transcript of Conference Call, dated November 12, 2012.
99.3	Presentation Materials.

MATADOR RESOURCES COMPANY REPORTS 2012 THIRD QUARTER FINANCIAL RESULTS AND PROVIDES OPERATIONAL UPDATE

DALLAS, Texas, November 12, 2012 – Matador Resources Company (NYSE: MTDR) (“Matador” or the “Company”), an independent energy company currently focused on the oil and liquids rich portion of the Eagle Ford shale play in South Texas, today reported financial and operating results for the three and nine months ended September 30, 2012. Headlines include the following:

- **Record oil production of 303,000 Bbl for the third quarter of 2012, a sequential quarterly increase of 6.3% from 285,000 Bbl produced in the second quarter of 2012 and a year-over-year increase of over seven-fold from 43,000 Bbl produced in the third quarter of 2011.**
- **Record average daily oil equivalent production of 8,838 BOE per day for the third quarter of 2012, including 3,291 Bbl of oil per day and 33.3 MMcf of natural gas per day; a year-over-year increase of 28% from the third quarter of 2011.**
- **Record total realized revenues of $41.4 million for the third quarter of 2012, including $3.4 million in realized gain on derivatives, a year-over-year increase of 119% from total realized revenues of $18.9 million, including $1.4 million in realized gain on derivatives, reported for the third quarter of 2011.**
- **Record oil and natural gas revenues of $38.0 million, for a year-over-year increase of 118% from $17.4 million reported for the third quarter of 2011.**
- **Record Adjusted EBITDA of $28.6 million, a year-over-year increase of 137% from $12.1 million reported for the third quarter of 2011.**
- **The Company will hold an Analyst Day in Dallas, Texas, on December 6 at 10:00 a.m. Central Time to review its 2013 operational plan and forecasts.**
- **Matador’s 2013 capital expenditures budget anticipated to be modestly lower than the 2012 level of $313 million.**

Third Quarter 2012 Financial Results

Joseph Wm. Foran, Matador’s Chairman, President and CEO, commented, “The third quarter saw continued strong growth in EBITDA as our drilling program in our Eagle Ford shale acreage continues to drive important growth in oil production and reserve values. To that end it is a pleasure to report that Matador produced more oil in the final six weeks of the third quarter of 2012 than we did in all of 2011. We continue to see improvements in our drilling and completion costs, even as production grows, and we continue to improve our drilling and completion techniques, which should lead to improvements in cash flow, rates of return and long-term asset value for our shareholders. Matador’s budget for 2013 capital expenditures is anticipated to be modestly lower than the $313 million in capital expenditures budgeted for 2012. This budget reflects our rich opportunity set in the Eagle Ford shale and our opportunity for exploration in the Delaware Basin and potentially even the Pearsall shale, balanced with our assessment that the pricing and operating environment may be softening to the point where maintaining financial discipline and flexibility will become increasingly important.”

Production and Revenues

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Oil production increased over seven-fold to approximately 303,000 Bbl of oil, or about 3,291 Bbl of oil per day, during the third quarter of 2012 as compared to approximately 43,000 Bbl of oil, or about 465 Bbl of oil per day, in the third quarter of 2011. This increase in oil production is a direct result of ongoing drilling operations in the Eagle Ford shale. Average daily oil equivalent production increased to approximately 8,838 BOE per day (37% oil by volume) in the third quarter of 2012 as compared to 6,931 BOE per day (7% oil by volume) during the third quarter of 2011.

Total realized revenues, including realized gain on derivatives, increased 119% to $41.4 million for the three months ended September 30, 2012 as compared to $18.9 million for the three months ended September 30, 2011. Oil and natural gas revenues increased 118% to $38.0 million in the third quarter of 2012 as compared to $17.4 million during the third quarter of 2011. This increase in oil and natural gas revenues reflects an increase in oil revenues of $26.4 million coupled with a decrease in natural gas revenues of $5.8 million between the respective periods. Oil revenues increased over eight-fold to $30.1 million for the three months ended September 30, 2012 as compared to $3.7 million in oil revenues for the three months ended September 30, 2011. A portion of this increase in oil revenues also reflects a higher weighted average oil price of $99.33 per Bbl realized during the three months ended September 30, 2012 as compared to a weighted average oil price of $85.92 per Bbl realized during the three months ended September 30, 2011. The decrease in natural gas revenues reflects a decline in natural gas production by about 14% to approximately 3.1 Bcf in the third quarter of 2012 as compared to approximately 3.6 Bcf in the third quarter of 2011. This decline in natural gas production is due to several factors, including (i) the natural decline in natural gas production primarily from existing Cotton Valley and Haynesville shale wells in Northwest Louisiana and East Texas, coupled with the decision not to drill any operated Haynesville shale wells in 2012, (ii) the voluntary curtailment of natural gas production from certain non-operated Haynesville shale wells in Northwest Louisiana and (iii) the flaring of a portion of the natural gas produced from newly completed Eagle Ford shale wells in South Texas as a result of gas pipeline constraints and awaiting the installation of permanent production facilities. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.59 per Mcf realized during the three months ended September 30, 2012 as compared to a weighted average natural gas price of $3.86 per Mcf realized during the three months ended September 30, 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Oil production increased almost seven-fold to approximately 788,000 Bbl of oil, or about 2,876 Bbl of oil per day, during the first nine months of 2012 as compared to approximately 113,000 Bbl of oil, or about 414 Bbl of oil per day, during the first nine months of 2011. This increase in oil production is a direct result of ongoing drilling and completion operations in the Eagle Ford shale during which time Matador also benefited from declining drilling and completion costs of approximately 10% to 15% per well on average. Average daily oil equivalent production increased to approximately 8,534 BOE per day (34% oil by volume) during the first nine months of 2012 from approximately 7,081 BOE per day (6% oil by volume) during the first nine months of 2011.

Total realized revenues, including realized gain on derivatives, increased 103% to $114.4 million for the nine months ended September 30, 2012 as compared to $56.2 million for the nine months ended September 30, 2011. Oil and natural gas revenues increased 99% to $103.3 million during the first nine months of 2012 from $52.0 million during the comparable period in 2011. This increase in oil and natural gas revenues reflects an increase in oil revenues of $70.6 million and a decrease in natural gas revenues of $19.3 million between the respective periods. Oil revenues increased almost eight-fold to $81.0 million for the nine months ended September 30, 2012 as compared to $10.5 million for the nine months ended September 30, 2011.

Adjusted EBITDA

Adjusted EBITDA, a non-GAAP financial measure, increased 137% to $28.6 million for the three months ended September 30, 2012 as compared to $12.1 million for the three months ended September 30, 2011. Sequentially, Adjusted EBITDA increased 3% to $28.6 million during the third quarter of 2012 from $27.9 million during the second quarter of 2012.

Adjusted EBITDA increased 107% to $77.9 million for the nine months ended September 30, 2012 as compared to $37.6 million during the first nine months of 2011. Notably, the Adjusted EBITDA of $77.9 million reported for the first nine months of 2012 compares to an Adjusted EBITDA of $49.9 million reported for all of last year (2011). *For a definition of Adjusted EBITDA and a reconciliation of net income (GAAP) and net cash provided by operating activities (GAAP) to Adjusted EBITDA (non-GAAP), please see "Supplemental Non-GAAP Financial Measures" below.*

Proved Reserves and PV-10

Proved oil reserves at September 30, 2012 increased almost eight-fold to approximately 8.4 million Bbl as compared to 1.1 million Bbl at September 30, 2011. At September 30, 2012, total proved reserves were approximately 20.9 million BOE, including approximately 8.4 million Bbl of oil (40% oil by volume) and 74.9 Bcf of natural gas, with a present value of estimated future net cash flows discounted at 10%, or PV-10, of $363.6 million (Standardized Measure of $333.9 million) as compared to total proved reserves at September 30, 2011 of approximately 27.0 million BOE, including approximately 1.1 million Bbl of oil (4% oil by volume) and 155.3 Bcf of natural gas, with a PV-10 of $155.2 million (Standardized Measure of $143.4 million). As a result of declines in natural gas prices, the Company previously removed approximately 16.3 million BOE in proved undeveloped Haynesville shale natural gas reserves from its total proved reserves at June 30, 2012. The reserves estimates in all periods presented were prepared by the Company's engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. *For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), please see "Supplemental Non-GAAP Financial Measures" below.*

Net (Loss) Income

For the quarter ended September 30, 2012, Matador reported a net loss of approximately $9.2 million and a loss of $0.17 per common share compared to net income of approximately $6.2 million and earnings of $0.14 per Class A common share and $0.21 per Class B common share for the quarter ended September 30, 2011. All Class B shares were converted to Class A shares upon completion of the Company's initial public offering in February 2012; there is only one class of common shares outstanding at September 30, 2012.

The net loss reported for the third quarter of 2012 is primarily attributable to non-cash charges, principally an unrealized loss on derivatives of approximately $13.0 million and a full-cost ceiling impairment charge to operations of $3.6 million recorded in the quarter. The unrealized loss on derivatives is attributable to a change in the net fair value of the Company's commodity derivatives during the period primarily as a result of increases in oil and natural gas prices between June 30 and September 30, 2012. The change in the net fair value of the Company's commodity derivatives can be volatile from period to period, and in fact, this unrealized loss of approximately $13.0 million compares to and partially offsets the unrealized gain on derivatives of approximately $15.1 million reported for the second quarter of 2012. The full-cost ceiling impairment was primarily attributable to the continued decline in the average natural gas price the Company is required to use to estimate its natural gas reserves, as well as smaller than anticipated reserves additions from the two Austin Chalk/"Chalkleford" wells drilled and completed in Zavala County, Texas during the quarter.

Sequential Financial Results

- Oil production increased 6% to approximately 303,000 Bbl, or 3,291 Bbl of oil per day in the third quarter of 2012 from approximately 285,000 Bbl, or 3,131 Bbl of oil per day, in the second quarter of 2012. Total proved oil and natural gas reserves increased approximately 10% to 20.9 MMBOE at September 30, 2012 from 19.1 MMBOE at June 30, 2012.
- Oil and natural gas revenues increased 5% to $38.0 million in the third quarter of 2012 from $36.1 million in the second quarter of 2012.
- The present value of estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, or PV-10, increased 20% to $363.6 million at September 30, 2012 from $303.4 million at June 30, 2012.
- Adjusted EBITDA increased 3% to $28.6 million in the third quarter of 2012 from $27.9 million in the second quarter of 2012.

Operating Expenses Update

Production Taxes and Marketing

Production taxes and marketing expenses increased to $2.8 million (or $3.47 per BOE) for the three months ended September 30, 2012 from $1.8 million (or $2.90 per BOE) for the three months ended September 30, 2011. The increase in production taxes and marketing expenses reflects the increase in total oil and natural gas revenues by 118% during the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The majority of this increase was attributable to production taxes and marketing expenses associated with the large increase in oil production resulting from drilling operations in the Eagle Ford shale in South Texas.

Lease Operating Expenses ("LOE")

Lease operating expenses increased to $6.5 million (or $7.98 per BOE) for the three months ended September 30, 2012 from $2.1 million (or $3.24 per BOE) for the three months ended September 30, 2011. The increase in lease operating expenses was primarily attributable to increased costs associated with operating high volume oil production as a result of ongoing drilling and completion operations in the Eagle Ford shale in 2012, as compared to the lower lease operating expenses associated with dry gas production. In addition, oil production comprised 37% of total production by volume during the three months ended September 30, 2012 as compared to only 7% of total production by volume during the same period in 2011, resulting in these higher overall lease operating expenses during the third quarter of 2012.

Depletion, depreciation and amortization ("DD&A")

Depletion, depreciation and amortization expenses increased to $21.7 million (or $26.66 per BOE) for the three months ended September 30, 2012 from $7.3 million (or $11.43 per BOE) for the three months ended September 30, 2011. This increase in depletion, depreciation and amortization expense was attributable to the decrease in total proved oil and natural gas reserves to 20.9 million BOE at September 30, 2012 as compared to 27.0 million BOE at September 30, 2011. As noted above, as a result of declines in natural gas prices, the Company previously removed approximately 16.3 million BOE in proved undeveloped Haynesville shale natural gas reserves from its total proved reserves at June 30, 2012. This increase in depletion, depreciation and amortization expense was also partially due to the increase of approximately 28% in total oil and natural gas production to approximately 813,000 BOE during the three months ended September 30, 2012 as compared to approximately 638,000 BOE during the three months ended September 30, 2011, as well as to the higher drilling and completion costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with the Company's Haynesville shale natural gas and other gas assets in Northwest Louisiana.

General and administrative ("G&A")

General and administrative expenses decreased to $3.4 million (or $4.23 per BOE) for the three months ended September 30, 2012 as compared to $4.2 million (or $6.60 per BOE) for the three months ended September 30, 2011. The decrease in general and administrative expenses was attributable primarily to decreased stock based compensation expense, partially offset by increased compensation, accounting, legal and other administrative expenses, much of which is associated with becoming a public company in February 2012.

Operations Update

Eagle Ford Shale – South Texas

During the first nine months of 2012, Matador's operations were focused on the exploration and development of its Eagle Ford shale properties in South Texas. In the third quarter of 2012 specifically, 6 gross/5.3 net operated and 1 gross/0.2 net non-operated Eagle Ford shale wells were completed and placed on production along with 2 gross/2 net operated Austin Chalk/"Chalkleford" wells. Two of these Eagle Ford operated wells were on the Love lease in DeWitt County, two on the Northcut lease in LaSalle County, one on the Martin Ranch lease in LaSalle County, and one on the Sickenius lease in Karnes County. One upper Austin Chalk well and one lower Austin Chalk/upper Eagle Ford, or "Chalkleford," well were drilled and completed on the Glasscock Ranch lease in Zavala County. The two wells on the Love lease began producing during August 2012; the two wells on the Northcut lease and the well drilled on the Sickenius lease began producing in September. The well drilled on the Martin Ranch lease did not begin producing until late September. As a result, these six wells did not contribute fully to the third quarter production volumes. Matador currently has two contracted drilling rigs operating in South Texas: one in LaSalle County and one in DeWitt County.

During the third quarter of 2012, Matador drilled the two wells on the Love lease back to back and performed "zipper-frac" operations on those two wells. The two wells on the Northcut lease were also drilled back to back with "zipper-fracs" pumped on the wells. The decision to drill wells back to back and to utilize "zipper-frac" techniques did result in a delay of first production from these wells of approximately 30 to 60 days compared to the typical time frame for independently drilled and fracture stimulated wells. While it is early in the production life of these two sets of "zipper-frac" wells, the results look favorable enough to warrant further tests and study. Matador is continuing to improve its drilling and completion techniques for these Eagle Ford wells and is encouraged by the results of these latest stimulation changes as well as the reductions being achieved in drilling and completion times and costs. Early results from these tests in DeWitt, Karnes and LaSalle counties indicate improved well performance as a result of recent fracture treatment modifications and operational practices such as restricting choke sizes. Matador continues to see benefits in flowing back the wells on restricted chokes and will continue to utilize this practice in the foreseeable future to maintain bottomhole pressure and to reduce stress on the rock and the proppant, even though such practices may result in smaller volumes of oil in the short term. Matador believes these operational improvements will extend the periods these wells can flow without artificial lift, thereby reducing LOE expenses in the short term and increasing ultimate recoveries in the long run.

Matador continues to evaluate results from recent wells drilled on 80-acre spacing on two of its Eagle Ford properties and, based on this early evaluation, Matador plans to continue drilling offset wells on 80-acre spacing on some of its other Eagle Ford acreage. Matador has also finalized a natural gas gathering, transportation and processing agreement, including firm transportation and processing, for most of its operated natural gas production in South Texas. This agreement will ensure that Matador has access to the market for the natural gas and natural gas liquids produced from its Eagle Ford properties.

Matador has recently begun placing some of its more mature producing wells on artificial lift. While still in the early stages, it appears as though this program should be successful in sustaining production volumes from wells that are in need of assistance in order to optimize production. While most of the current installations of artificial lift are in the form of pumping units and rod pumps, Matador is evaluating other possible artificial lift methods to maximize production from these wells.

Matador has drilled three wells on its 9,000 acre block in Zavala County, Texas. The three wells included an Eagle Ford test, an upper Austin Chalk test, and a lower Austin Chalk/Upper Eagle Ford, or "Chalkleford," test. None of these wells were particularly strong, but all three wells continue to produce oil with the assistance of artificial lift. Matador will continue to evaluate the performance of all three wells while studying other potential formations on the acreage block, including the Pearsall shale, and studying offset well performance from wells completed in other zones. Matador remains optimistic that this acreage block may yield favorable results with further study and technical progress.

Haynesville Shale – Northwest Louisiana

Matador has no plans to drill any operated Haynesville shale wells for the remainder of 2012, but is participating in several non-operated Haynesville wells where it has working interests throughout 2012. As a result of low natural gas prices, several non-operated Haynesville shale wells were shut in for brief periods or produced less natural gas than anticipated during the first nine months of 2012 as the operators voluntarily curtailed a portion of the natural gas production from these wells.

Meade Peak Shale – Wyoming, Utah and Idaho

During the third quarter, Matador and its partner finalized commercial arrangements related to the ongoing exploration of the Meade Peak shale. Operations are scheduled to begin in the fourth quarter of 2012 to conduct a horizontal test of the Meade Peak shale. A rig is on location. The existing Crawford Federal #1 vertical wellbore was drilled and cored through the Meade Peak shale and then suspended in December 2011. Plans are to re-enter this existing wellbore, plug back to a sufficient depth to sidetrack and drill a horizontal lateral to test the Meade Peak formation. Matador's share of the anticipated costs of this operation will be carried by its partner. Matador and its partner also intend to renew leases that may be available for renewal and may acquire additional leasehold within their area of mutual interest.

Acreage Acquisitions

On August 10, 2012, Matador added to its existing acreage position in the Delaware Basin with the acquisition of approximately 4,900 gross and 2,900 net acres in the heart of the Wolfbone play in Loving County, Texas. The Company expects to begin testing this acreage as well as to add to its other acreage positions in the next twelve months.

Liquidity Update

On September 28, 2012, the Company closed an amended and restated senior secured revolving credit agreement. Under the credit agreement, the borrowing base was increased to $200 million, up from the previous borrowing base of $125 million based on June 30, 2012 reserves estimates. The amendment increased the maximum facility size from $400 million to $500 million and named Royal Bank of Canada as Administrative Agent.

At September 30, 2012, the Company had cash and cash equivalents and certificates of deposits totaling approximately $4.4 million, approximately $106.0 million of outstanding long-term borrowings and approximately $1.1 million in outstanding letters of credit. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3%. In October 2012 and November 2012, Matador borrowed an additional $14.0 million and $15.0 million, respectively, under its credit agreement to finance a portion of working capital requirements and capital expenditures. As of November 12, 2012, the Company had $135.0 million in outstanding long-term borrowings and approximately $1.1 million in outstanding letters of credit. The borrowing base will be redetermined based upon December 31, 2012 reserves estimates, although Matador may also request a redetermination based on its reserves growth at September 30, 2012.

Capital Spending

At September 30, 2012, Matador has incurred approximately $237.6 million or about 76% of its anticipated 2012 capital expenditures budget of $313 million. This includes approximately $21.2 million incurred to acquire additional leasehold acreage primarily in the Eagle Ford shale near the Company's existing properties and in the Delaware Basin in West Texas. As of September 30, 2012, Matador is executing its 2012 capital expenditures program as planned and remains within its anticipated capital expenditures budget for 2012.

Hedging Positions

For the fourth quarter of 2012, Matador has hedged 360,000 Bbl of its anticipated oil production using costless collars having a weighted average floor price of $90.83 per Bbl and a weighted average ceiling price of $110.31 per Bbl.

For the fourth quarter of 2012, Matador has hedged 2.31 Bcf of its anticipated natural gas production using costless collars having a weighted average floor price of $4.07 per MMBtu and a weighted average ceiling price of $5.30 per MMBtu.

For the fourth quarter of 2012, Matador has hedged 625,200 gallons of its anticipated natural gas liquids production using swaps having a weighted average price of $0.81 per gallon.

2012 Guidance Update

Matador anticipates its 2012 annual oil production will be near the lower end of its previously announced guidance of 1.2 to 1.4 million barrels. The Company reaffirms its previous 2012 guidance announced on March 7, 2012 and May 14, 2012 for (1) estimated capital spending of $313 million, (2) an estimated exit rate for oil production of 5,000 to 5,500 Bbl per day and (3) estimated total natural gas production of 12.5 to 13.5 Bcf.

2013 Guidance Announcement

Matador's budget for 2013 capital expenditures is anticipated to be modestly lower than the $313 million in capital expenditures budgeted for 2012. This preliminary budget estimate reflects the Company's rich opportunity set in the Eagle Ford shale and its opportunity for exploration in the Delaware Basin in West Texas and potentially the Pearsall shale and Buda in South Texas, balanced with its assessment that the pricing environment may be softening and maintaining financial discipline is key. Additional elements of the Company's 2013 plan will be discussed in detail during its upcoming Analyst Day on Thursday, December 6, 2012.

Matador Analyst Day

Matador will be hosting an Analyst Day on Thursday, December 6, 2012 at 10:00 a.m. Central Time at the Company's headquarters in Dallas, Texas. The meeting will include an overview of its 2013 operational plan, capital budget and forecasts, plus an update on geology and drilling and completion techniques in its areas of operation. The call will be available via webcast and details will be released closer to the date.

Conference Call Information and Investor Presentation

The Company will host a conference call on Monday, November 12, 2012, at 9:00 a.m. Central Time to discuss its third quarter 2012 financial and operational results. To access the conference call, domestic participants should dial (866) 314-5050 and international participants should dial (617) 213-8051. The participant passcode is 73985344. The conference call will also be available through the Company's website at www.matadorresources.com on the Presentations & Webcasts page under the Investors tab. To access the conference call, domestic participants should dial (866) 314-5050 and international participants should dial (617) 213-8051. The participant passcode is 73985344. The replay for the event will also be available on the Company's website at www.matadorresources.com through Wednesday, November 21, 2012. In addition, the Company's updated Investor Presentation is available on the Presentations & Webcasts page under the Investors tab of the Company's website at www.matadorresources.com.

About Matador Resources Company

Matador is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Its current operations are located primarily in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas.

For more information, visit Matador Resources Company at www.matadorresources.com.

Forward-Looking Statements

This press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project" and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements. These forward-looking statements involve certain risks and uncertainties and ultimately may not prove to be accurate, including, but not limited to, the following risks related to financial and operational performance: general economic conditions; ability for Matador to execute its business plan, including the success of its drilling program; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; ability to replace reserves and efficiently develop current reserves; costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; ability to make acquisitions on economically acceptable terms; availability of sufficient capital to Matador to execute its business plan, including from future cash flows, increases in borrowing base and otherwise; weather and environmental concerns; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's Annual Report on Form 10-K for the year ended December 31, 2011. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after this press release, except as required by law. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this press release. All forward-looking statements are qualified in their entirety by this cautionary statement.

Contact Information

Mac Schmitz
Investor Relations
(972) 371-5225
mschmitz@matadorresources.com

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED BALANCE SHEETS – UNAUDITED

(In thousands, except par value and share data)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,178	$ 10,284
Certificates of deposit	266	1,335
Accounts receivable		
Oil and natural gas revenues	17,046	9,237
Joint interest billings	4,252	2,488
Other	591	1,447
Derivative instruments	6,395	8,989
Lease and well equipment inventory	1,478	1,343
Prepaid expenses	974	1,153
Total current assets	35,180	36,276
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	654,292	423,945
Unproved and unevaluated	164,514	162,598
Other property and equipment	24,597	18,764
Less accumulated depletion, depreciation and amortization	(295,042)	(205,442)
Net property and equipment	548,361	399,865
Other assets		
Derivative instruments	1,880	847
Deferred income taxes	1,878	1,594
Other assets	1,537	887
Total other assets	5,295	3,328
Total assets	$ 588,836	$ 439,469
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 17,364	$ 18,841
Accrued liabilities	50,262	25,439
Royalties payable	5,920	1,855
Borrowings under Credit Agreement	—	25,000
Derivative instruments	—	171
Advances from joint interest owners	1,782	—
Income taxes payable	188	—
Deferred income taxes	1,878	3,024
Dividends payable - Class B	—	69
Other current liabilities	56	177
Total current liabilities	77,450	74,576
Long-term liabilities		
Borrowings under Credit Agreement	106,000	88,000
Asset retirement obligations	4,551	3,935
Derivative instruments	142	383
Other long-term liabilities	1,465	1,060
Total long-term liabilities	112,158	93,378
Shareholders' equity		
Common stock - Class A, $0.01 par value, 80,000,000 shares authorized; 56,697,718 and 42,916,668 shares issued; 55,505,209 and 41,737,493 shares outstanding, respectively	567	429
Common stock - Class B, $0.01 par value, zero and 2,000,000 shares authorized; zero and 1,030,700 shares issued and outstanding, respectively	—	10
Additional paid-in capital	403,248	263,562
Retained earnings	6,178	18,279
Treasury stock, at cost, 1,192,509 and 1,179,175, respectively	(10,765)	(10,765)
Total shareholders' equity	399,228	271,515
Total liabilities and shareholders' equity	$ 588,836	$ 439,469

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS – UNAUDITED

(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues				
Oil and natural gas revenues	$ 38,008	$ 17,447	$ 103,250	$ 52,009
Realized gain on derivatives	3,371	1,435	11,147	4,237
Unrealized (loss) gain on derivatives	(12,993)	2,870	(1,149)	1,534
Total revenues	28,386	21,752	113,248	57,780
Expenses				
Production taxes and marketing	2,822	1,848	7,605	4,801
Lease operating	6,491	2,065	17,511	5,639
Depletion, depreciation and amortization	21,680	7,288	52,799	22,578
Accretion of asset retirement obligations	59	61	170	158
Full-cost ceiling impairment	3,596	—	36,801	35,673
General and administrative	3,439	4,207	11,321	9,919
Total expenses	38,087	15,469	126,207	78,768
Operating (loss) income	(9,701)	6,283	(12,959)	(20,988)
Other income (expense)				
Net loss on asset sales and inventory impairment	—	—	(60)	—
Interest expense	(144)	(171)	(453)	(461)
Interest and other income	55	82	157	248
Total other expense	(89)	(89)	(356)	(213)
(Loss) income before income taxes	(9,790)	6,194	(13,315)	(21,201)
Income tax provision (benefit)				
Current	188	—	188	(46)
Deferred	(781)	—	(1,430)	(6,906)
Total income tax benefit	(593)	—	(1,242)	(6,952)
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)
Earnings (loss) per common share				
Basic				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B	$ —	$ 0.21	$ (0.03)	$ (0.14)
Diluted				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B	$ —	$ 0.21	$ (0.03)	$ (0.14)
Weighted average common shares outstanding				
Basic				
Class A	55,271	41,720	53,379	41,671
Class B	—	1,031	140	1,031
Total	55,271	42,751	53,519	42,702
Diluted				
Class A	55,271	41,848	53,379	41,671
Class B	—	1,031	140	1,031
Total	55,271	42,879	53,519	42,702

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – UNAUDITED

(In thousands)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating activities		
Net loss	$ (12,073)	$ (14,249)
Adjustments to reconcile net loss to net cash provided by operating activities		
Unrealized loss (gain) on derivatives	1,149	(1,534)
Depletion, depreciation and amortization	52,799	22,578
Accretion of asset retirement obligations	170	158
Full-cost ceiling impairment	36,801	35,673
Stock option and grant expense	(585)	1,379
Restricted stock and restricted stock units expense	362	36
Deferred income tax benefit	(1,430)	(6,906)
Loss on asset sales and inventory impairment	60	—
Changes in operating assets and liabilities		
Accounts receivable	(8,718)	(2,411)
Lease and well equipment inventory	(285)	(1)
Prepaid expenses	179	240
Other assets	(650)	—
Accounts payable, accrued liabilities and other liabilities	6,105	(2,360)
Income taxes payable	188	—
Royalties payable	4,065	2,548
Advances from joint interest owners	1,782	(723)
Other long-term liabilities	406	15
Net cash provided by operating activities	80,325	34,443
Investing activities		
Oil and natural gas properties capital expenditures	(212,702)	(104,733)
Expenditures for other property and equipment	(5,297)	(3,303)
Purchases of certificates of deposit	(416)	(3,721)
Maturities of certificates of deposit	1,485	3,985
Net cash used in investing activities	(216,930)	(107,772)
Financing activities		
Repayments of borrowings under Credit Agreement	(123,000)	—
Borrowings under Credit Agreement	116,000	60,000
Proceeds from issuance of common stock	146,510	592
Swing sale profit contribution	24	—
Cost to issue equity	(11,599)	(1,185)
Proceeds from stock options exercised	2,660	837
Payment of dividends - Class B	(96)	(206)
Net cash provided by financing activities	130,499	60,038
Decrease in cash and cash equivalents	(6,106)	(13,291)
Cash and cash equivalents at beginning of period	10,284	21,059
Cash and cash equivalents at end of period	$ 4,178	$ 7,768

Matador Resources Company and Subsidiaries

SELECTED OPERATING DATA – UNAUDITED

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Production Volumes:				
Oil (MBbl)	303	43	788	113
Natural gas (Bcf)	3.1	3.6	9.3	10.9
Total oil equivalents (MBOE)[(1),(2)]	813	638	2,338	1,933
Average net daily production (BOE/d)[(2)]	8,838	6,931	8,534	7,081
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$100.56	$85.92	$104.25	$92.71
Oil, without realized derivatives (per Bbl)	$ 99.33	$85.92	$102.86	$92.71
Natural gas, with realized derivatives (per Mcf)	$ 3.57	$ 4.26	$ 3.47	$ 4.19
Natural gas, without realized derivatives (per Mcf)	$ 2.59	$ 3.86	$ 2.39	$ 3.80
Operating Expenses per BOE:				
Production taxes and marketing	$ 3.47	$ 2.90	$ 3.25	$ 2.48
Lease operating	$ 7.98	$ 3.24	$ 7.49	$ 2.92
Depletion, depreciation and amortization	$ 26.66	$11.43	$ 22.58	$11.68
General and administrative	$ 4.23	$ 6.60	$ 4.84	$ 5.13

(1) Thousands of barrels of oil equivalent.

(2) Estimated using a conversion ratio of one Bbl per six Mcf.

SELECTED ESTIMATED PROVED RESERVES DATA – UNAUDITED

	At September 30,[(1)]		At December 31,[(1)]
	2012	2011	2011
Estimated proved reserves:			
Oil (MBbl)	8,411	1,083	3,794
Natural Gas (Bcf)	74.9	155.3	170.4
Total (MBOE)[(2)]	20,894	26,971	32,194
Estimated proved developed reserves:			
Oil (MBbl)	3,783	519	1,419
Natural Gas (Bcf)	53.4	52.7	56.5
Total (MBOE)	12,686	9,294	10,836
Percent developed	60.7%	34.5%	33.7%
Estimated proved undeveloped reserves:			
Oil (MBbl)	4,628	565	2,375
Natural Gas (Bcf)	21.5	102.7	113.9
Total (MBOE)	8,208	17,677	21,358
PV-10 (in millions)	$ 363.6	$ 155.2	$ 248.7
Standardized Measure (in millions)	$ 333.9	$ 143.4	$ 215.5

(1) Numbers in table may not total due to rounding.

(2) Thousands of barrels of oil equivalent, estimated using a conversion ratio of one Bbl per six Mcf.

Supplemental Non-GAAP Financial Measures

Adjusted EBITDA

The Company defines Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock units expense and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. "GAAP" means Generally Accepted Accounting Principles in the United States of America.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of the Company's operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following tables present the calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(In thousands)

	Three Months Ended		Nine Months Ended		Three Months Ended	Three Months Ended	Year Ended
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011	June 30, 2012	December 31, 2011	December 31, 2011
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):							
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)	$ (6,676)	$ 3,941	$ (10,309)
Interest expense	144	171	453	461	1	222	683
Total income tax (benefit) provision	(593)	—	(1,242)	(6,952)	(3,713)	1,430	(5,521)
Depletion, depreciation and amortization	21,680	7,287	52,799	22,578	19,914	9,175	31,754
Accretion of asset retirement obligations	59	62	170	158	58	51	209
Full-cost ceiling impairment	3,596	—	36,801	35,673	33,205	—	35,673
Unrealized loss (gain) on derivatives	12,993	(2,870)	1,149	(1,534)	(15,114)	(3,604)	(5,138)
Stock option and grant expense	(252)	1,220	(585)	1,379	41	983	2,362
Restricted stock and restricted stock units expense	201	14	362	36	150	8	44
Net loss on asset sales and inventory impairment	—	—	60	—	60	154	154
Adjusted EBITDA	$ 28,631	$ 12,078	$ 77,894	$ 37,550	$ 27,926	$ 12,360	$ 49,911

	Three Months Ended		Nine Months Ended		Three Months Ended	Three Months Ended	Year Ended
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011	June 30, 2012	December 31, 2011	December 31, 2011
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:							
Net cash provided by operating activities	$ 28,799	$ 14,912	$ 80,325	$ 34,443	$ 46,416	$ 27,425	$ 61,868
Net change in operating assets and liabilities	(500)	(3,005)	(3,072)	2,692	(18,491)	(15,287)	(12,594)
Interest expense	144	171	453	461	1	222	683
Current income tax provision (benefit)	188	—	188	(46)	—	—	(46)
Adjusted EBITDA	$ 28,631	$ 12,078	$ 77,894	$ 37,550	$ 27,926	$ 12,360	$ 49,911

PV-10

PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of the properties. Matador and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. The PV-10 at September 30, 2012, June 30, 2012 and September 30, 2011 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at September 30, 2012, June 30, 2012 and September 30, 2011 were, in millions, $29.7, $21.9 and $11.8, respectively.

Conference Call Transcript
November 12, 2012
9:00 A.M. CST

Matador Resources Company Participants:
Joseph Wm. Foran: Founder, Chairman, Chief Executive Officer and President
David F. Nicklin: Executive Director—Exploration
David E. Lancaster: Executive Vice President, Chief Operating Officer and Chief Financial Officer
Matthew V. Hairford: Executive Vice President – Operations
Ryan London: Senior Completion Engineer, Eagle Ford Asset Manager

Presentation

Operator: Good morning, ladies and gentlemen. Welcome to the third quarter 2012 Matador Resources Company earnings conference call. My name is Erin, and I will be your operator for today. At this time, all participants are in a listen-only mode. We will facilitate a question and answer session toward the end of the conference. As a reminder, this call is being recorded for replay purposes and the replay will be available through Wednesday, November 21, 2012 as discussed and described in the Company's earnings release this morning.

Some of the presenters today will refer to certain non-GAAP financial measures regularly used by Matador Resources in measuring the Company's financial performance. Reconciliations of such non-GAAP financial measures with the comparable financial measures calculated in accordance with the GAAP are contained at the end of the Company's earnings release.

As a reminder, certain statements included in this morning's presentation may be forward-looking and reflect the Company's current expectations or forecasts of future events based on the information that is now available. Please refer to the forward-looking statement in the Company's earnings release for more information.

I would now like to turn the call over to Joe Foran, Chairman, President and CEO. You may proceed.

Joe Foran: Thank you, Erin. Good morning, everybody. This is Joe Foran, and I'm joined by the senior staff of Matador, including David Lancaster, Chief Operating Officer; David Nicklin, Executive Head of Exploration and Matt Hairford, Head of Operations.

As a brief introduction, Matador has been in business over 25 years in one form or another, and we have operated on a few simple principles, first, an excellent technical staff and board, good properties in good neighborhoods and financial discipline. 2012 has been about our development of our Eagle Ford acreage and increasing the oil profile of the Company.

The third quarter was a good step along that path. We are now about 80% oil by revenue. We have a two-rig drilling program in the Eagle Ford and our technical team has continued to cut drilling and completion costs while improving the performance of our wells. This has been accomplished through improvements in geosteering, reduced chokes and maintenance of bottom hole pressures, improvements in our frac design, including the use of zipper-fracs. If you look at the data we released earlier this year with our IP rates along with various choke sizes and well pressures, we think this information really attests to a very strong well performance and operating practices.

Some of the engineering choices have had the effect over the course of the year of our bringing the production online more slowly, as you know, than we had thought in the beginning of the year. But this is just a delay of production and not lost production.

More important, and as further testimony to that, I am happy to report that our oil production as of this morning is over 5000 barrels a day, which, as many of you know, is a very exciting milestone for the Company and an important target we wanted to achieve this year. So, all in all, we are very happy with the evolution of the Eagle Ford development plan.

It's also important to remember, we believe, that we have an important gas bank in our 5800 net acres in the tier one part of the Haynesville and about 10,000 acres in the north Louisiana part of the Cotton Valley. All this acreage is HBP, which gives the Company a very meaningful exposure to higher gas prices.

In terms of financial prudence, we announced during the quarter an expanded bank borrowing facility. We have no expensive debt on our balance sheet and expect to continue to spend within our cash flow plus growth in our bank facility. For 2013, we are expecting CapEx to be modestly lower than 2012. We have announced an analyst day for the Company on December 6 and we look forward to sharing details of our 2013 plan at that point.

Finally, on the acreage front, we have added about 2900 acres in the Delaware Basin to increase our net acreage to roughly 15,000 gross, 7500 acres net. For more information, we are releasing today an updated investor presentation for your reference.

With that, let's open the floor to questions. Erin?

Q&A Session

Operator: (Operator instructions) William Butler, Stephens.

William Butler: Good job on oil production, guys. Can you all maybe elaborate a little bit more on what EOG is doing on your Atascosa acreage? Is there any update you all can provide on that?

Joe Foran: David Nicklin, you're probably in the best position to answer that question. David is our Executive Head of Exploration.

David Nicklin: Yes, we do have a forward notice from EOG that before the end of this year they plan on spudding a horizontal well in the Buda within the Atascosa acreage. We are excited about that. It is a play we are very interested in and we look forward to moving forward with that.

William Butler: Okay. Is that an area that you all think would have prospectivity for the Pearsall? Are there any plans for you or EOG Resources there? Maybe can you speak a little more broadly regarding the Pearsall on you all's total acreage?

David Nicklin: Joe, would you like me to take that?

Joe Foran: Yes, why don't you continue?

David Nicklin: With regard to the Atascosa acreage, in particular, EOG have been doing a series of Pearsall wells and they have informed us that they are interested in Atascosa from the standpoint of the Pearsall, but they have a couple of other locations just outside of the Atascosa acreage to the south and they plan to drill those first before they finalize a location within the Atascosa acreage. So we are very interested in the Pearsall. We are watching it and studying it. There's quite a number of wells being drilled in and around our existing acreage where we do have Pearsall rights. So we — more in particular, our Martin Ranch area — there are wells permitted around the Martin Ranch area, and the Martin Ranch area is just to the south of some of the more promising liquids-rich production from the Pearsall.

So we have done regional studies and we are very intrigued and interested. We are not under any pressure to drill immediately, so we will continue to watch the play as it evolves.

Joe Foran: Thank you, David. That's a good response. I don't have anything to add to that, William, unless you have a follow-up to that.

William Butler: No, I will hop back in the queue.

Operator: Yiktat Fung, Jefferies & Co.

Yiktat Fung: My first question — I was just wondering if you could give us a little bit more color on the 2013 CapEx and how that is going to be allocated. Specifically, I'm interested in whether there will be a significant amount allocated to Haynesville now that gas prices have rebounded.

Joe Foran: We're going to really go into that on analyst day, and I don't want to try to jump the gun. The biggest I would say all about the gas prices is the Haynesville is HBP, so there's no rush to get there. And it's largely dependent on prices in the investor presentation that we are releasing later today. We show some sensitivities of the Haynesville to gas prices and to production cost, and we are certainly getting within range where it's starting to look attractive. But we will go into any plans for the Haynesville on analyst day, but that's about all I can say at this time.

Yiktat Fung: Okay, and I guess just one more from me — what are your current thoughts for the Zavala acreage now that you have tested all those different horizons and your results haven't been as exciting as they could be, I guess?

Joe Foran: The Zavala acreage was never critical. The critical part of our Eagle Ford development was across that 9000-foot contour. And we have drilled that and then, obviously, very pleased with all those results.

The Zavala was taken as exploration acreage. It's a little more up-dip in a more shallow horizon. So you don't have the benefit of geo-pressure. It's a more shallow depth. The oil is in place there, and on the one Eagle Ford test that we drilled there, it's going to make probably 100,000 barrels EUR, and a BOE equivalent. But that's a lot to work with, but that's not like as strong as our other Eagle Ford performance. That block of acreage is HBP, all rights, all depths, so we have plenty of time to look at it and study it. But there is oil there, and as you look at activity and look at the investor presentation that will be out today, you can see it's a very active area and other people are drilling. And so I think it still shows promise in the Eagle Ford, but it's at a different level than the rest of our Eagle Ford acreage.

Yiktat Fung: Thank you so much; I'll hop back in the queue.

Operator: (Operator instructions) Brian Corales, Howard Weil.

Brian Corales: In terms of Eagle Ford costs, can you maybe just talk about what you are seeing maybe trending down and maybe a guesstimate for what your future AFEs are going to be for 2013, maybe by LaSalle and in the DeWitt area?

Joe Foran: Ryan, would you like to take this?

Ryan London: Yes. Right now, our Eagle Ford costs are in the — on a normalized basis in our LaSalle area, it's the $7 million to $7.5 million range. And in the east, it kind of breaks out in two different costs. You have your deeper, high-pressure, higher temperature wells that are in the $10 million cost with resin-coated sand and the third string of casing. On the shallower side of our eastern acreage, it's in the $8.5 million to $9 million range. And 2013 looks — it's going to start off around the same, and maybe as we shave a little bit more here and there, maybe 10% less on top of those numbers.

Brian Corales: Okay. And then just switching to the Permian, is there a lot of other, kind of these smaller packages maybe that others — below the radar screen for? Are there other things that you all are looking at in the Permian to try to add to that inventory?

Joe Foran: I'm not sure what you're asking there, Brian.

Brian Corales: Is there other like packages? I think you added like 3000 or so acres. Is there other packages that you all are looking at, potentially can get — I think most of those may be flying are below the radar of some of the bigger players in the Permian.

Joe Foran: You mean acreage packages?

Brian Corales: Acreage packages, yes.

Joe Foran: We're going to be opportunistic. That's one thing that has been a little delay in setting the capital spending for next year, is to try to get a better view on what we wanted to spend on acreage acquisitions. This year, it was about $25 million, and we are seeing an increased number of opportunities all around. So, no, we are — Brian, as you know, we're always very opportunistic, particularly on land. And we are seeing more, but we have not really committed to anything other than what we have announced.

Brian Corales: Okay. But you all don't see anything out there right now that gets you excited?

Joe Foran: No. Sometimes it's things that get you excited, but it's a matter of price and negotiation. So we are seeing a lot of, I think, very attractive acreage opportunities in a number of locations, but just trying to determine which is the best and being selective has been more of a concern.

Brian Corales: Okay, thank you.

Operator: Stephen Shepherd, Simmons & Co.

Stephen Shepherd: Just real quick, is there any leasehold spend baked into your 2013 capital guidance at this point, or does the "modestly lower" language from your press release pertain specifically to drill bit CapEx?

Joe Foran: Can you clarify that, Steve? I'm not sure I understand.

Stephen Shepherd: I'm just asking — in the press release, you mentioned that capital spending would be modestly lower year-over-year. Are you talking just with regard to drill bit CapEx, or is that a total CapEx number? And if so —

Joe Foran: It's a total number, Steve. Last year, in 2012, we spent about $25 million. So it was less than 10% of the total budget. I'm not sure what it will be this year, but when I talked about it being modestly lower, I'm talking about just the whole budget itself.

Stephen Shepherd: Okay, that's great, and one more, if I could. You mentioned earlier that 4Q oil production had surpassed that 5000-barrel mark. Was that something that you all achieved just within the past few days, or was that sometime earlier in the quarter, in October? I just wondered if you could brighten that up a little bit for me.

Joe Foran: Stephen, that's just recently.

Stephen Shepherd: Okay, perfect, thank you.

Operator: Yiktat Fung, Jefferies & Co.

Yiktat Fung: Just a couple more questions — on the acre spacing, 80-acre spacing test, can you remind me where that is and how much data you have gotten so far in terms of how long those wells have been on, and if you see any interference so far?

Joe Foran: David Lancaster, would you like to try that question?

David Lancaster: Yes, sir, I'd be happy to. There have been a couple of places now where we have, for sure, tried the 80-acre spacing. One is on the Love tract that we have in DeWitt County, and the other one is on our Northcut tract that we have in LaSalle County. And we drilled most of these 80-acre offsets recently, so we don't have a great deal of information from them yet. I would say the two Northcut wells — we have probably got on the order of a couple of months now, and on the Love wells, probably just a couple weeks. But I would say so far, so good. I don't think we are seeing any evidence of any interference at this point. I would have been surprised if we had, frankly.

Yiktat Fung: And just one last one — did you recently bring a couple of new wells online, or what is the quarter looking like in terms of when the new wells are coming online?

Joe Foran: We expect to have four, maybe five wells come online during these last six weeks of the quarter, and that would be two on Martin Ranch, one on Northcut and Lewton number two.

Yiktat Fung: Okay, all right, thank you so much.

Operator: Thank you, ladies and gentlemen, this ends the Q&A portion of this morning's conference call. I would like to turn the call over to management for any closing remarks.

Joe Foran: Thank you, Erin. Just want to remind everybody, for a little more color there will be an investor presentation that will be released today and available on our website and will be 8-K'ed.

Finally, I would like to close by simply saying I'm now the largest shareholder in the Company, and I want to say how pleased and proud I am of Matador and how it is doing and how well the staff has performed this year. We have a great staff, we have some great properties and we believe we have a great outlook for the next year and hope you will join us on Analyst Day, December 6. Thank you all very much for listening in and hope to see you all soon.

Operator: Ladies and gentlemen, thank you for your participation today. This concludes the program.

Exhibit 99.3



Investor Presentation

November 2012

Forward-Looking Statements

This presentation and statements made by representatives of Matador Resources Company ("Matador" or the "Company") during the course of this presentation include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project" and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements. These forward-looking statements involve certain risks and uncertainties and ultimately may not prove to be accurate, including, but not limited to, the following risks related to our financial and operational performance: general economic conditions; Matador's ability to execute its business plan, including the success of its drilling program; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; our ability to replace reserves and efficiently develop our current reserves; our costs of operations, delays and other difficulties related to producing oil, natural gas and natural gas liquids; our ability to make acquisitions on economically acceptable terms; availability of sufficient capital to Matador to execute its business plan, including from our future cash flows, increases in our borrowing base, joint venture partners and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's Annual Report on Form 10-K for the year ended December 31, 2011. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.



Company Summary

Matador History

Predecessor Entities

Foran Oil & Matador Petroleum

- Founded by Joe Foran in 1983
- Foran Oil funded with $270,000 in contributed capital from 17 friends and family members
- Sold to Tom Brown, Inc.[1] in June 2003 for an enterprise value of $388 million in an all-cash transaction

Matador Today

Matador Resources Company

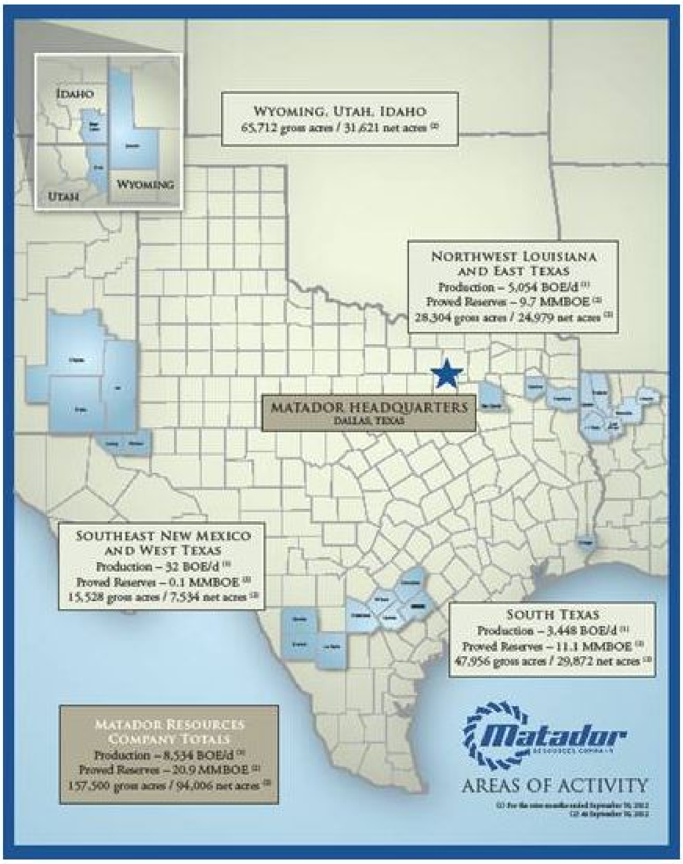
- Founded by Joe Foran in 2003 with a proven management and technical team and board of directors
- Grown through the drill bit, with focus on unconventional reservoir plays, initially in Haynesville
- In 2008, sold Haynesville rights in approximately 9,000 net acres to Chesapeake for approximately $180 million; retained 25% participation interest, carried working interest and overriding royalty interest
- Relatively early in the play, redeployed capital into the Eagle Ford, acquiring over 30,000 net acres for approximately $100 million, most in 2010 and 2011
- Capital spending focused on developing Eagle Ford and transition to oil
- IPO in February 2012 (NYSE: MTDR) had net cash proceeds of approximately $136.6 million

(1) Tom Brown purchased by Encana in 2004

Investment Highlights

- **Strong Growth Profile with Increasing Focus on Oil / Liquids**
  - Oil production up almost five-fold in 2011 and projected to increase 8x to 9x in 2012
  - 2012E capital expenditure program focused on oil and liquids exploration and development
- **High Quality Asset Base in Attractive Areas**
  - Eagle Ford provides immediate oil-weighted value and upside
  - Expanding acreage position in Delaware Basin in West Texas
  - Other key assets provide long-term option value on natural gas, with Haynesville, Bossier and Cotton Valley assets all essentially HBP
- **Significant Multi-year Drilling Inventory**
- **Strong Financial Position and Prudent Risk Management**
- **Proven Management, Technical Team and Active Board of Directors**
  - Management averaging over 25 years of industry experience
  - Board with extensive industry experience and expertise as well as significant company ownership
  - Strong record of stewardship for over 28 years
- **Active Exploration Effort Using Science and Technology**
  - Ongoing pipeline of new oil and natural gas opportunities, with strong emphasis on science and technology to create value

Matador Resources Snapshot



Daily Production[1]	**8,534 BOE/d**
Oil Production (% total)	2,876 Bbl/d (34%)
Proved Reserves @ 9/30/12	**20.9 Million BOE**
% Proved Developed	61%
% Oil	40% (and growing)
2012E CapEx	**$313 million**
% Eagle Ford	84%
% Oil and Liquids	94%
2012E Anticipated Drilling	**29.5 net wells**
Eagle Ford / Austin Chalk	27.6 net wells
Haynesville	1.5 net wells
Gross Acreage[2]	**157,500 acres**
Net Acreage[2]	**94,006 acres**

(1) Average daily production for the nine months ended September 30, 2012
(2) At September 30, 2012

Eagle Ford

South Texas

Eagle Ford and Austin Chalk Overview

Proved Reserves @ 9/30/12	**11.1 Million BOE**
% Proved Developed	46%
% Oil / Liquids	75%
Daily Oil Production (1)	**3,448 BOE/d**
Gross Acres(2)	**47,956 acres**
Net Acres(2)	**29,872 acres**
Eagle Ford(2),(3)	29,872 acres
Austin Chalk (2),(3)	17,191 acres
2012E Anticipated Drilling	**27.6 net wells**
2012E CapEx Budget	**$268.5 million**

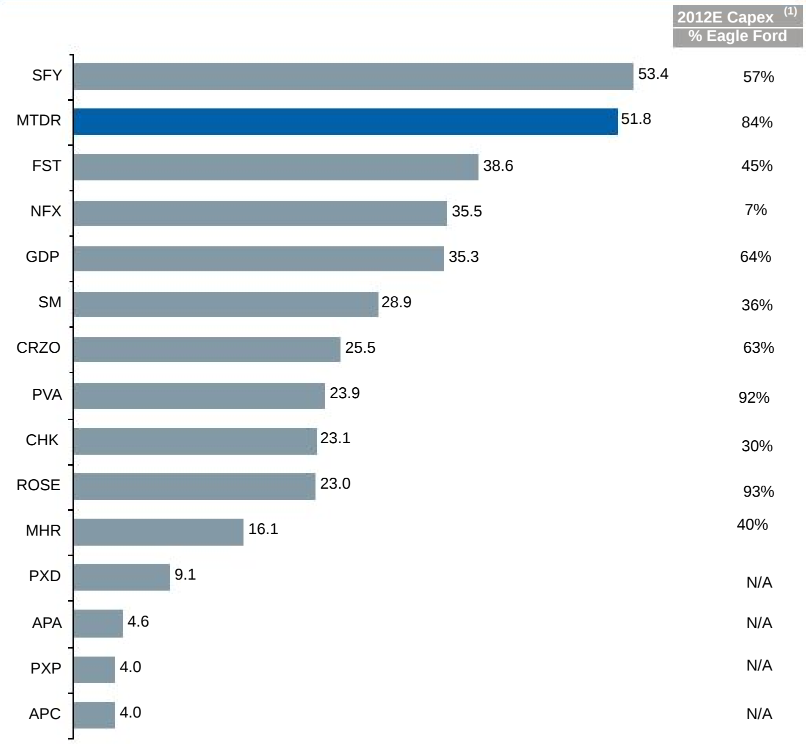
(1) Average daily oil production for the nine months ended September 30, 2012
(2) At September 30, 2012
(3) Some of the same leases cover the net acres shown for Eagle Ford and Austin Chalk. Therefore, the sum for both formations is not equal to the total net acreage

- Acreage positioned in some of the most active counties for Eagle Ford and Austin Chalk (including “Chalkleford”)
- Two rigs running, primarily focused on oil and liquids
- 2012E capital expenditure program focused on oil and liquids exploration and development
- Anticipate oil production to constitute approx. 35-40% of total production volume and oil revenues to constitute approx. 75-80% of total oil and natural gas revenues in 2012
- Drilling locations are based on 120 acre spacing
  - Currently testing 80-acre spacing on one Eagle Ford property and plan additional tests on other properties before end of 2012

Leading Eagle Ford Exposure

- Matador offers significant leverage and focus to the Eagle Ford
- Approximately 90% of Eagle Ford acreage is in the prospective oil and liquids window
- All 2012E Eagle Ford drilling focused in the prospective oil and liquids window
- 84% of 2012 estimated CapEx allocated to Eagle Ford
- One rig running in the eastern and one in the western portions of the Eagle Ford play
- Eagle Ford acreage well-positioned throughout the play

Leverage to Eagle Ford (Net Eagle Ford Acres / EV)
(Net Acres / $mm)

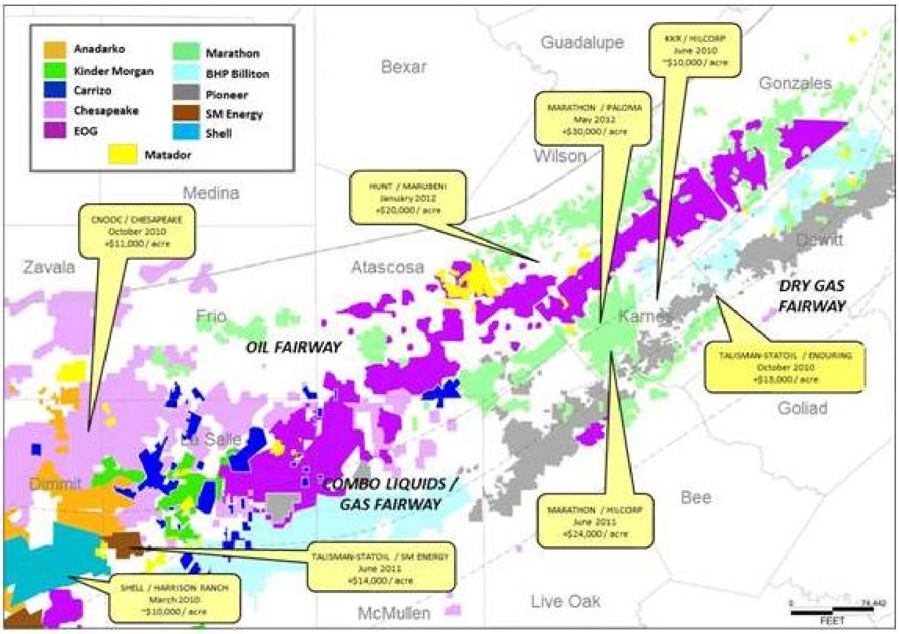


Note: Reflects companies with greater than 50 Bcfe of proved reserves. Data sourced from public filings; stock price data as of November 7, 2012 close
(1) Per operational guidance

Eagle Ford Properties are in Good Neighborhoods

Highlights

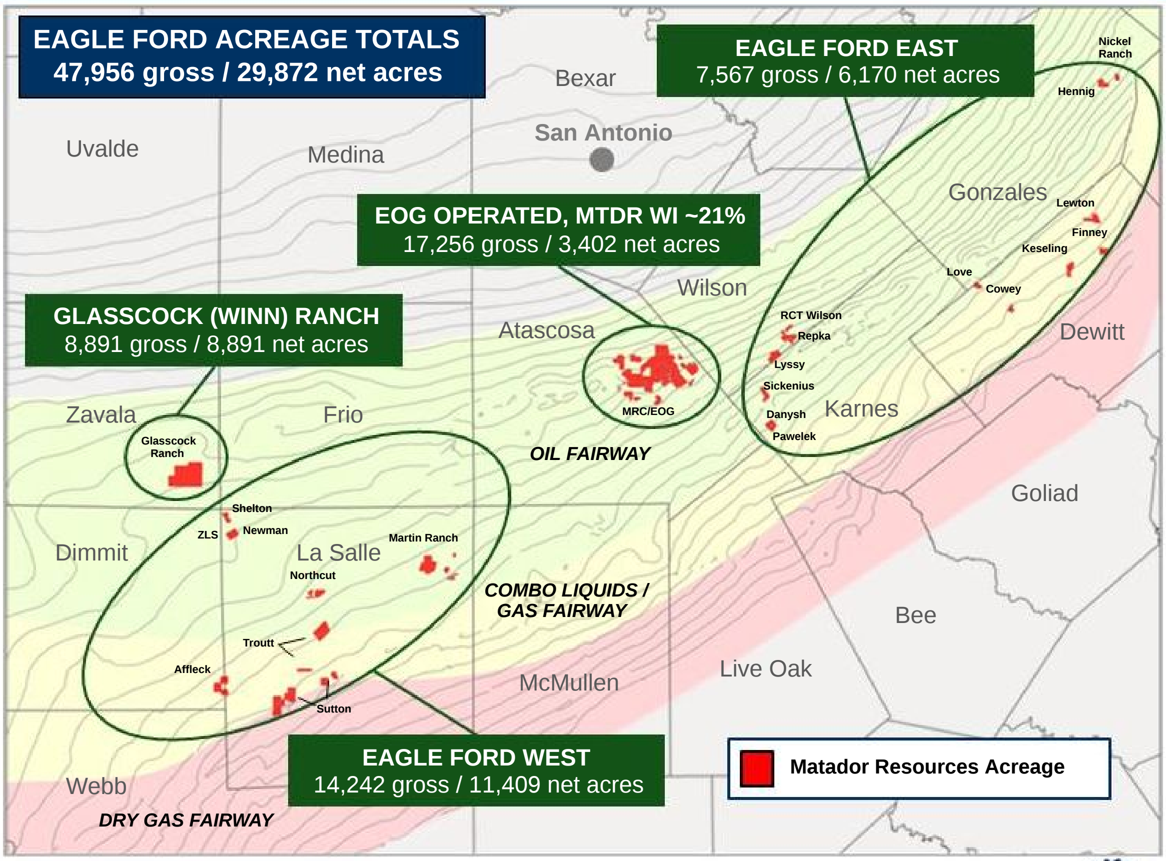
- MTDR acreage in counties with robust transaction activity – "good neighborhoods"
- Transaction values ranging from \$10,000 to \$30,000 per acre
- Our Eagle Ford position has grown to approximately 30,000 net acres
- Acreage in both the eastern and western areas of the play
- Approximately 90% of acreage in prospective oil and liquids windows
- Acreage offers potential for Austin Chalk, Buda, Pearsall and other formations



- Good reputation with land and mineral owners

Note: All Matador acreage at September 30, 2012 and all other acreage based on public information

Eagle Ford and Austin Chalk Properties



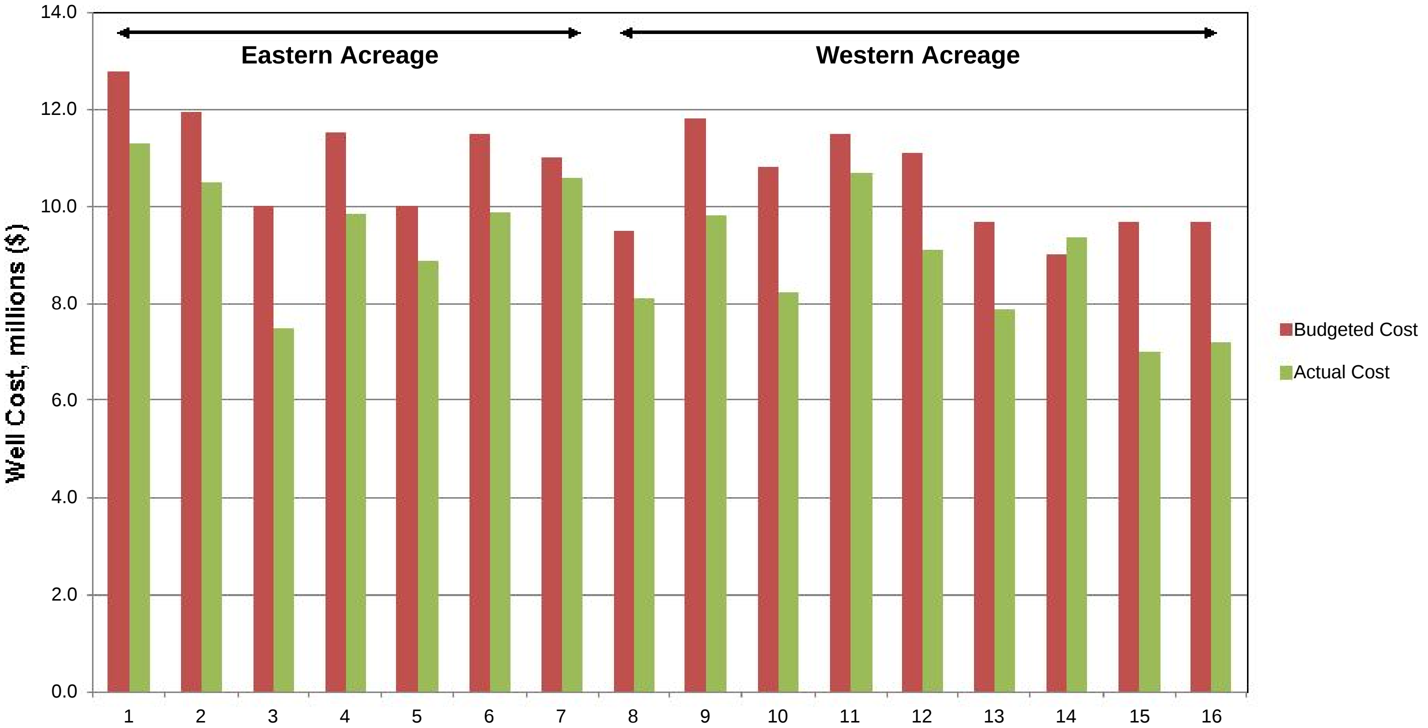
Note: All acreage at September 30, 2012

Eagle Ford 24-Hour Stabilized Rates

Well Name	County	Completion Date	Perforated Length [1] Total (ft.)	Frac Stages	Oil IP[2][3] (Bbl/day)	Gas IP[2][3] (Mcf/day)	Oil Equiv IP[4] (BOE/day)	Choke (inch)	Pressure (psi)
2011 Wells									
JCM Jr. Minerals 1H	La Salle	11/10/2010	3,774	15	164	3,648	772	15/64	3,365
Martin Ranch A 1H	La Salle	1/20/2011	4,201	17	1,129	2,821	1,599	34/64	1,550
Affleck 1H	Dimmit	2/22/2011	4,711	16	456	5,247	1,331	36/64	1,435
Frances Lewton 1H	DeWitt	11/16/2011	5,041	17	1,021	2,574	1,450	13/64	5,000
Martin Ranch A 2H	La Salle	11/19/2011	6,772	22	1,318	1,845	1,626	26/64	1,800
Martin Ranch A 3H	La Salle	11/26/2011	4,476	15	802	510	887	26/64	1,510
Martin Ranch A 5H	La Salle	12/17/2011	4,518	15	893	545	984	26/64	1,250
2012 Wells									
Martin Ranch A 8H	La Salle	1/28/2012	6,092	21	1,089	831	1,228	26/64	1,750
Martin Ranch A 6H	La Salle	2/8/2012	6,509	22	689	1,714	975	26/64	1,650
Martin Ranch A 7H	La Salle	2/12/2012	4,902	17	609	481	689	26/64	1,040
Martin Ranch B 4H	La Salle	2/18/2012	3,551	13	595	968	756	26/64	1,320
Matador Sickenius Orca 1H	Karnes	3/16/2012	5,712	19	785	540	875	26/64	820
Northcut A 1H	La Salle	3/23/2012	4,446	15	583	592	682	26/64	1,000
Matador Danysh Orca 1H	Karnes	4/1/2012	4,962	17	1,012	1,126	1,200	26/64	1,175
Northcut A 2H	La Salle	5/1/2012	4,503	15	758	761	885	24/64	950
Matador Pawelek Orca 1H	Karnes	6/5/2012	6,103	20	670	739	793	16/64	2,510
Matador Pawelek Orca 2H	Karnes	6/7/2012	6,202	28	861	755	987	16/64	2,460
Matador Danysh Orca 2H	Karnes	6/10/2012	5,115	17	750	746	874	16/64	2,675
Glasscock Ranch 1H	Zavala	6/27/2012	5,352	18	307	0	307	pump	140
Matador K. Love Orca 1H	DeWitt	8/10/2012	5,077	17	1,793	2,171	2,155	16/64	5,280
Matador K. Love Orca 2H	DeWitt	8/11/2012	4,871	17	1,757	2,126	2,111	16/64	5,900
Average			**5,090**	**18**	**859 Bbl/day**	**1,464 Mcf/day**	**1,103 BOE/day**		

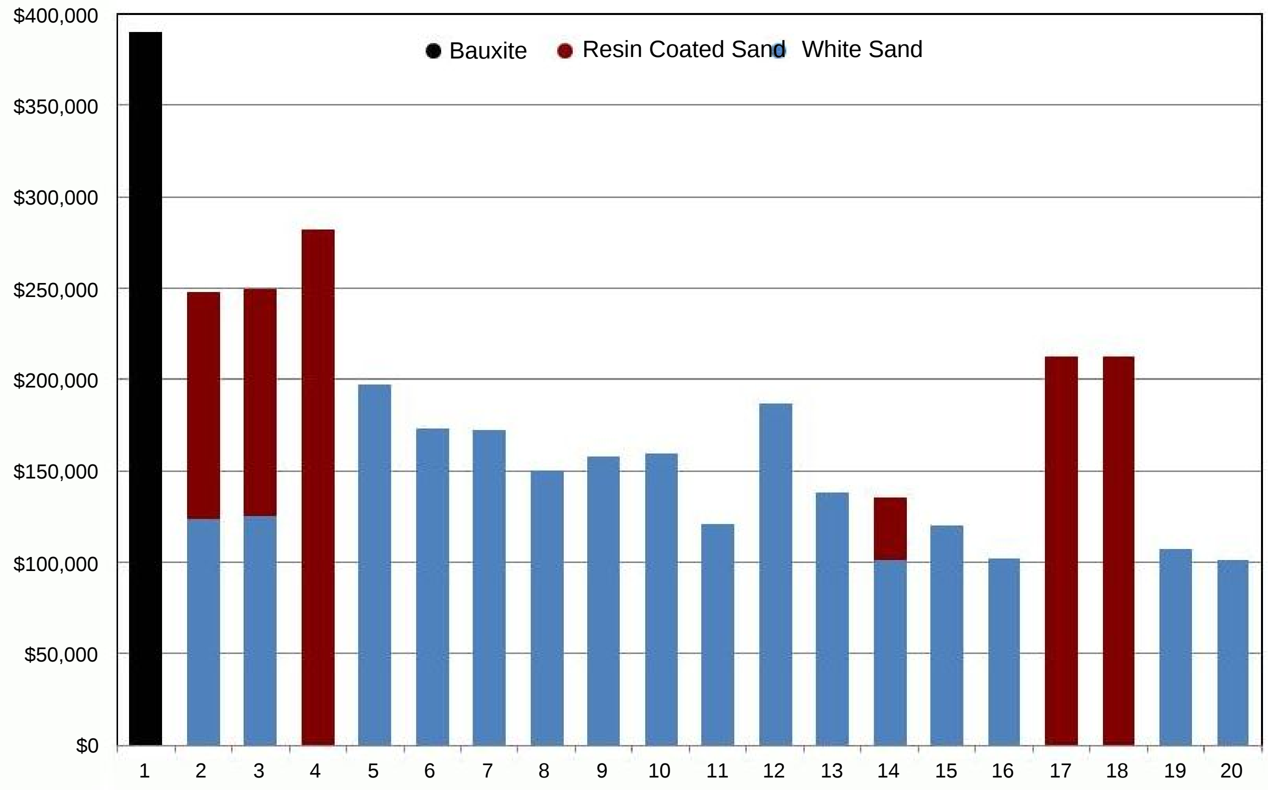
(1) Total length of perforated lateral from the first perforation to the last perforation
(2) Rates as reported to the Texas Railroad Commission via W-2 or G-1 form
(3) Rates are based on actual, stabilized, 24-hour production on a constant choke size
(4) Oil equivalent rates are based on a 6:1 ratio of six Mcf gas per one Bbl oil

Eagle Ford Well Costs Averaging 15% Less than 2012 Budget Estimates



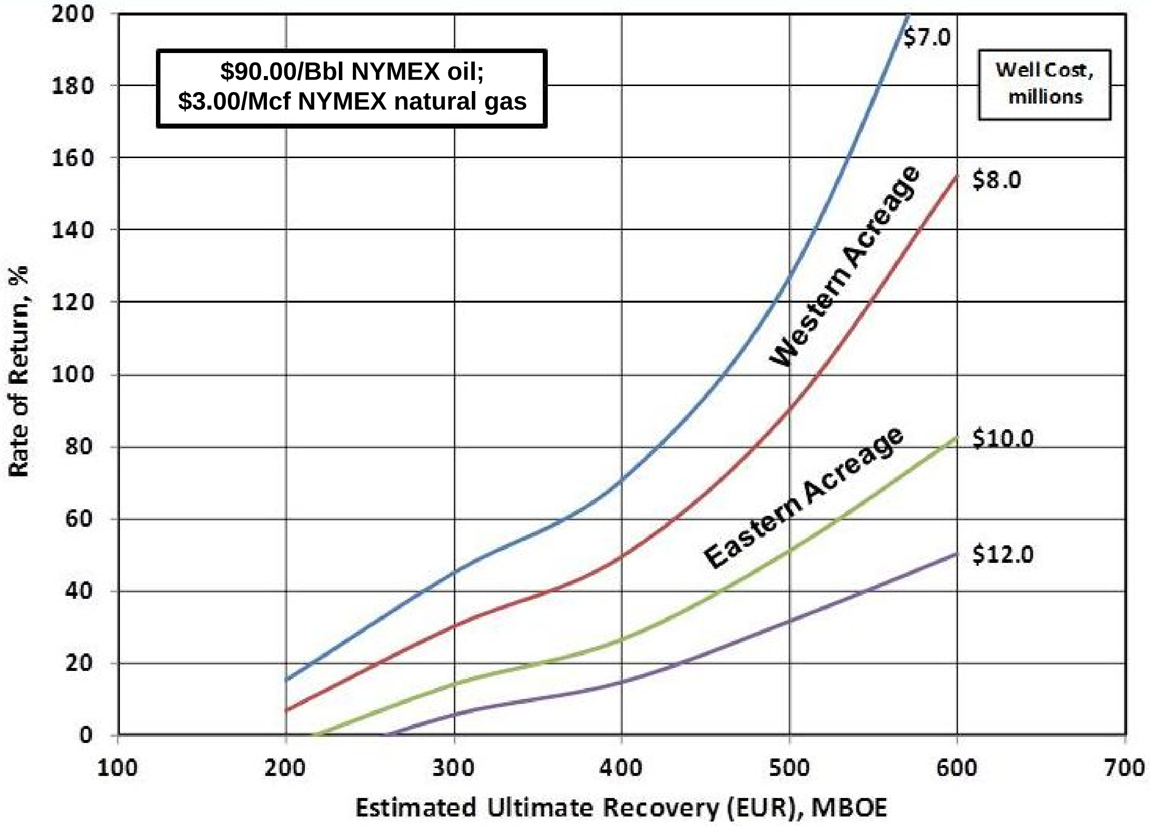
Note: 2012 Eagle Ford well drilling and completions costs only compared to budget estimates; costs do not include pipelines and lease facilities

Average Frac Stage Cost per Well



Note: Wells are displayed in chronological order

Eagle Ford Well Estimated ROR as a Function of EUR and Well Cost



Note: Individual well economics only. NGL price differential +$2.50/Mcf. Oil price differential +$4.30/Bbl.

Technical Advancements in the Eagle Ford

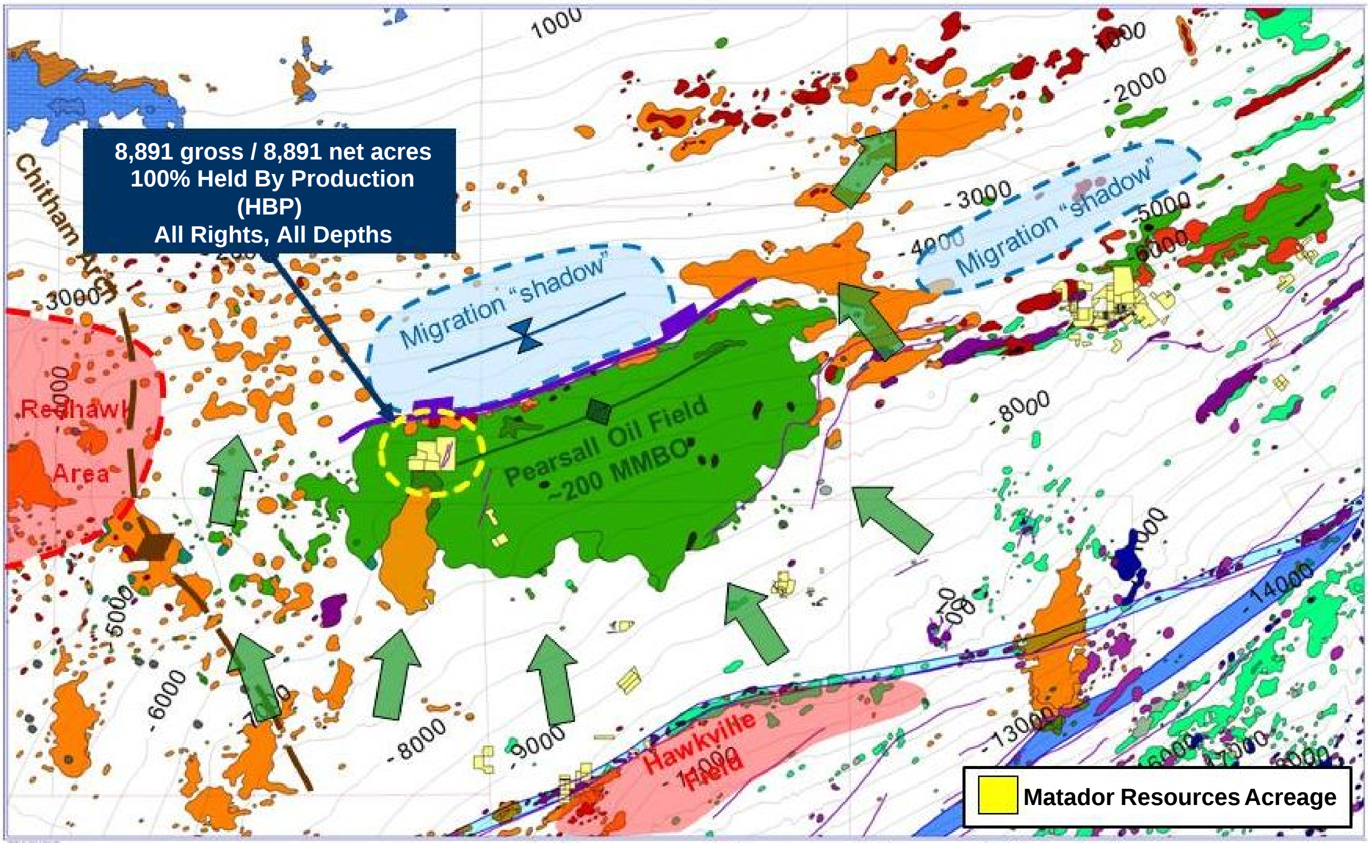
- **Rotary Steerable Tools**
  - Drilling time in curve and lateral reduced by 2 days
  - Measurement While Drilling (MWD) telemetry closer to drill bit
    - Improves ability to stay in "sweet-spot"
    - Removes sumps and high-angle curves
- **Improved frac design**
  - Increases Stimulated Rock Volume (SRV)
    - Tighter fracture spacing (25% more created fractures than previous design)
    - 35 Bbl/ft. frac fluid (75% increase from previous design)
  - Zipper Fracs (simultaneous frac operations)
    - Daily fixed cost reduced by 20%
    - Increases drainage efficiency
- **Choke size reduction**
  - Delays effects of pressure-dependent formation permeability
    - Increases Estimated Ultimate Recovery (EUR)
    - Delays installation of artificial lift
  - Lowers bottom-hole pressure differential
    - Mitigates damage to proppant pack
- **Artificial lift**
  - Pumping Units with pump-off controllers on low-gas/oil ratio (GOR) wells
  - Gas-lift valves on high-gas/oil ratio (GOR) wells
  - Electric Submersible Pumps (ESP) to accelerate unloading frac fluids

Zavala

Eagle Ford & Pearsall Trend

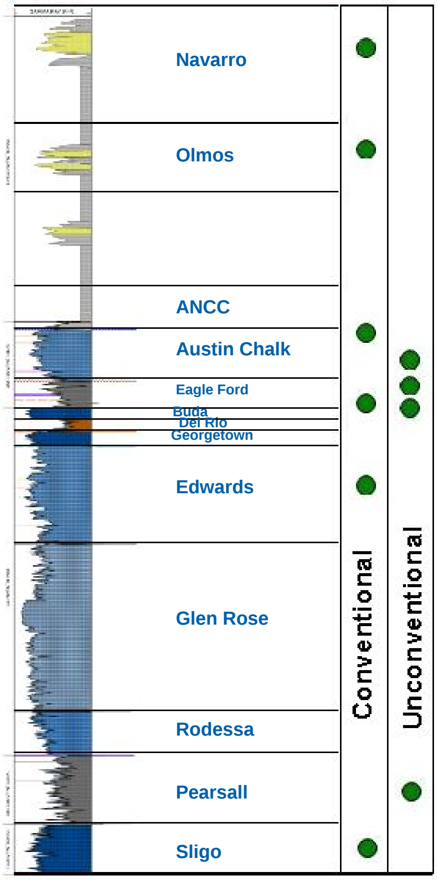
South Texas Multi-Pay Petroleum Systems: Upside Potential in Zavala County



Note: All acreage at September 30, 2012
Note: Information for Pearsall Oil Field sourced from public information

Oil and Gas Fields: Olmos/Navarro, Austin Chalk, Edwards, Buda, Wilcox

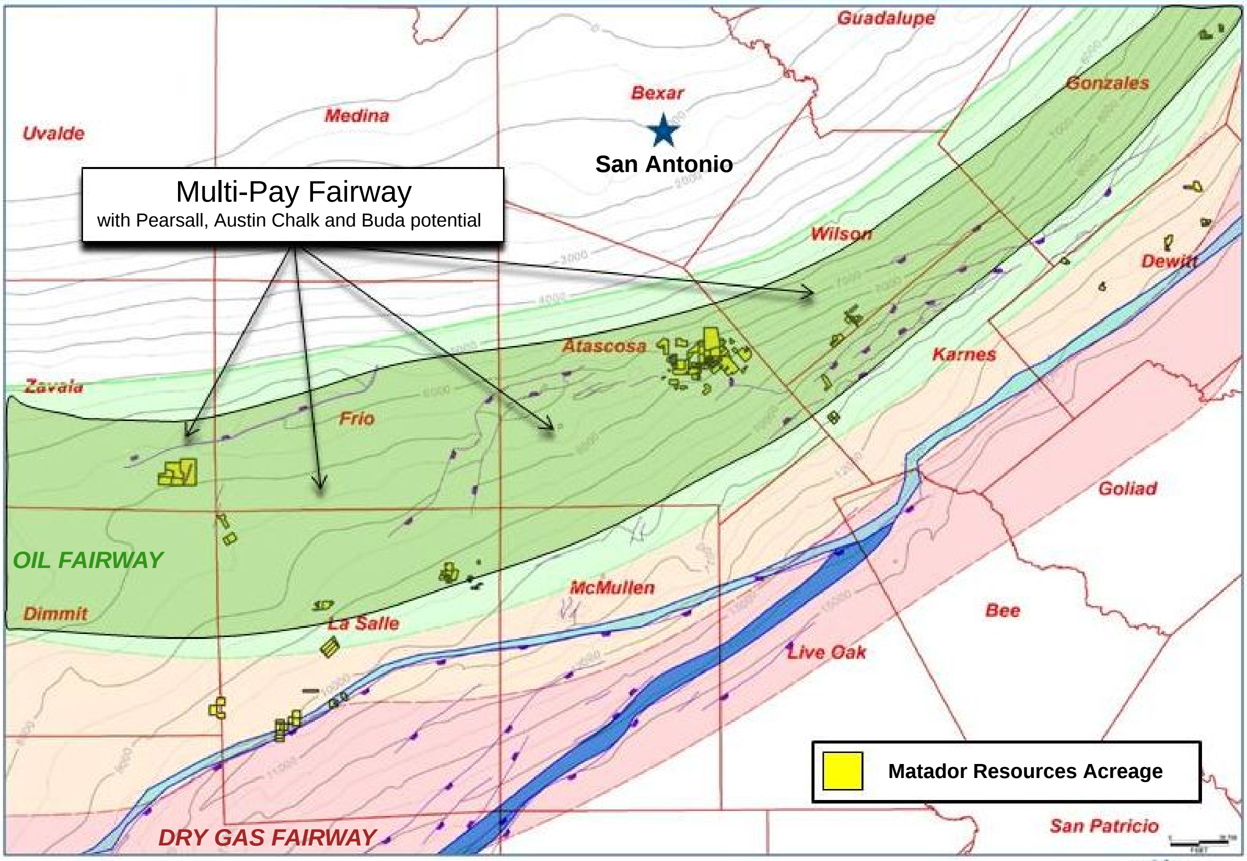
Multi-Pay Fairway: Productive and Prospective Pay Zones



- **Historic Conventional Zones**
  - Olmos-Navarro
    - Gas and oil fields in shallow section
  - Austin Chalk
    - Upper Austin horizontal drilling
    - Fractured reservoir
  - Buda
    - Primarily productive on structure
    - Fractured reservoir
  - Edwards
    - Productive on structure

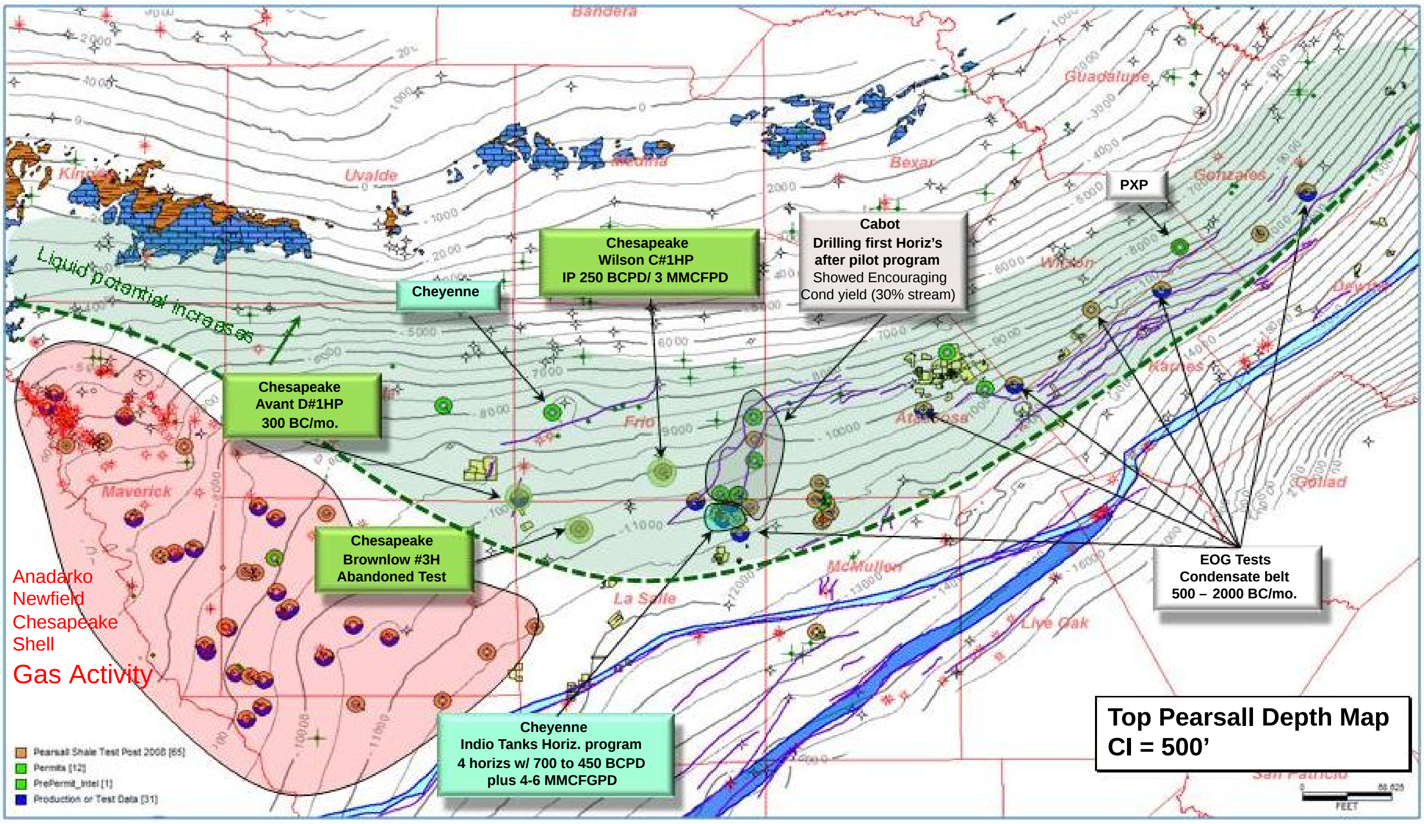
- **"New" Unconventional Zones**
  - "Chalkleford" *(Eagle Ford / Austin Chalk transition zone)*
    - Recent results in Pearsall Field from other operators are positive
  - Eagle Ford
    - Lower costs combined with better completion techniques have improved initial results in northern oil window
  - Horizontal Buda Drilling
    - Exploratory play developing to exploit fracturing within the Buda both on and off structure
  - Pearsall Shale
    - Exploratory play, initial test wells now being drilled

Emerging Multi-Pay Area in Eagle Ford Oil Fairway and MTDR Acreage



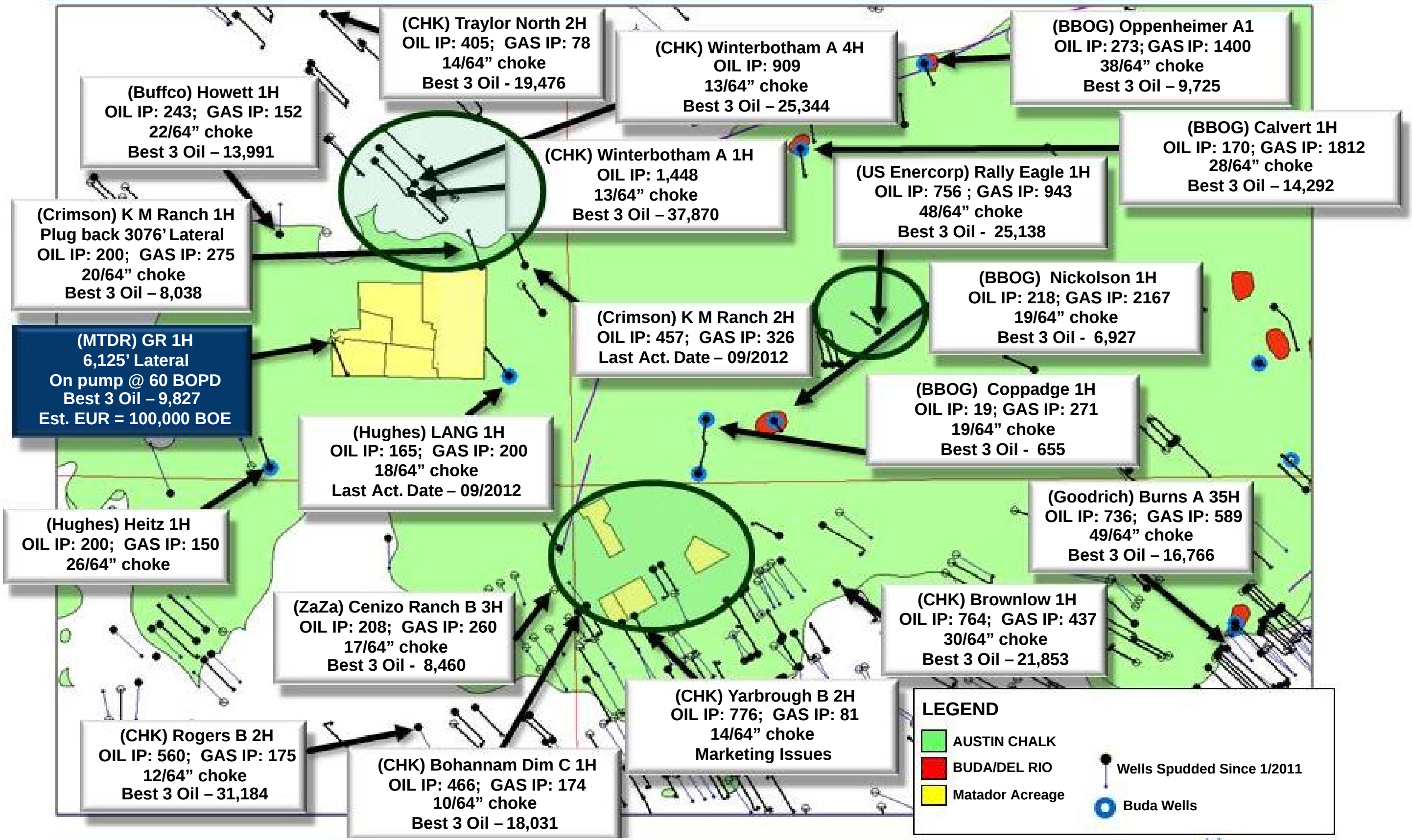
Note: All acreage at September 30, 2012

South Texas Pearsall Play: Activity & Liquids to Dry Gas Distribution Model



Note: Well data available through public sources and interpretation by Matador Resources

Zavala, Frio, La Salle and Dimmit Counties: Important Matador and Competitor Eagle Ford Wells Since 2011



Note: Well data available through public sources and interpretation by Matador Resources



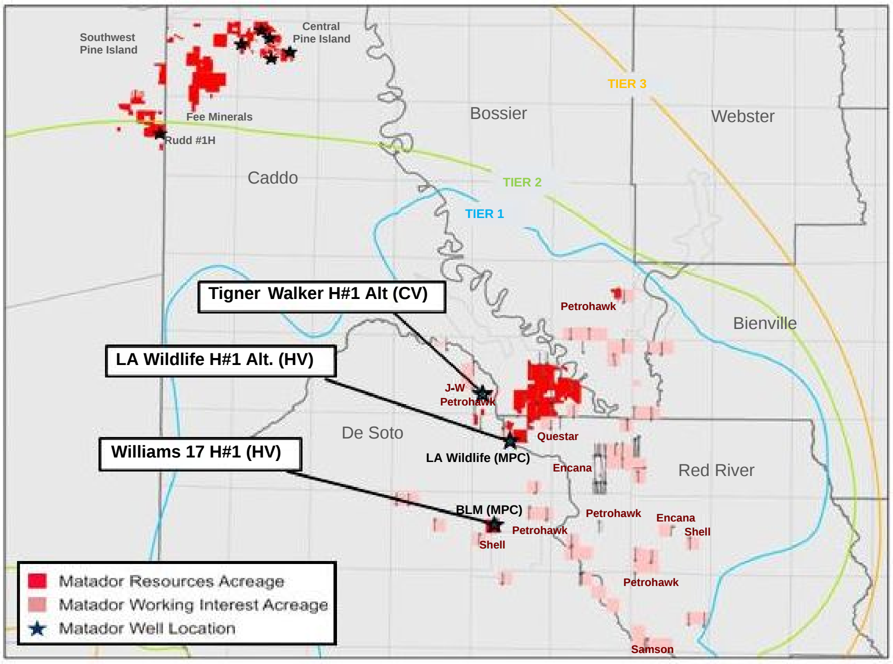
Haynesville & Cotton Valley

Northwest Louisiana and East Texas

Haynesville Positioning

Highlights

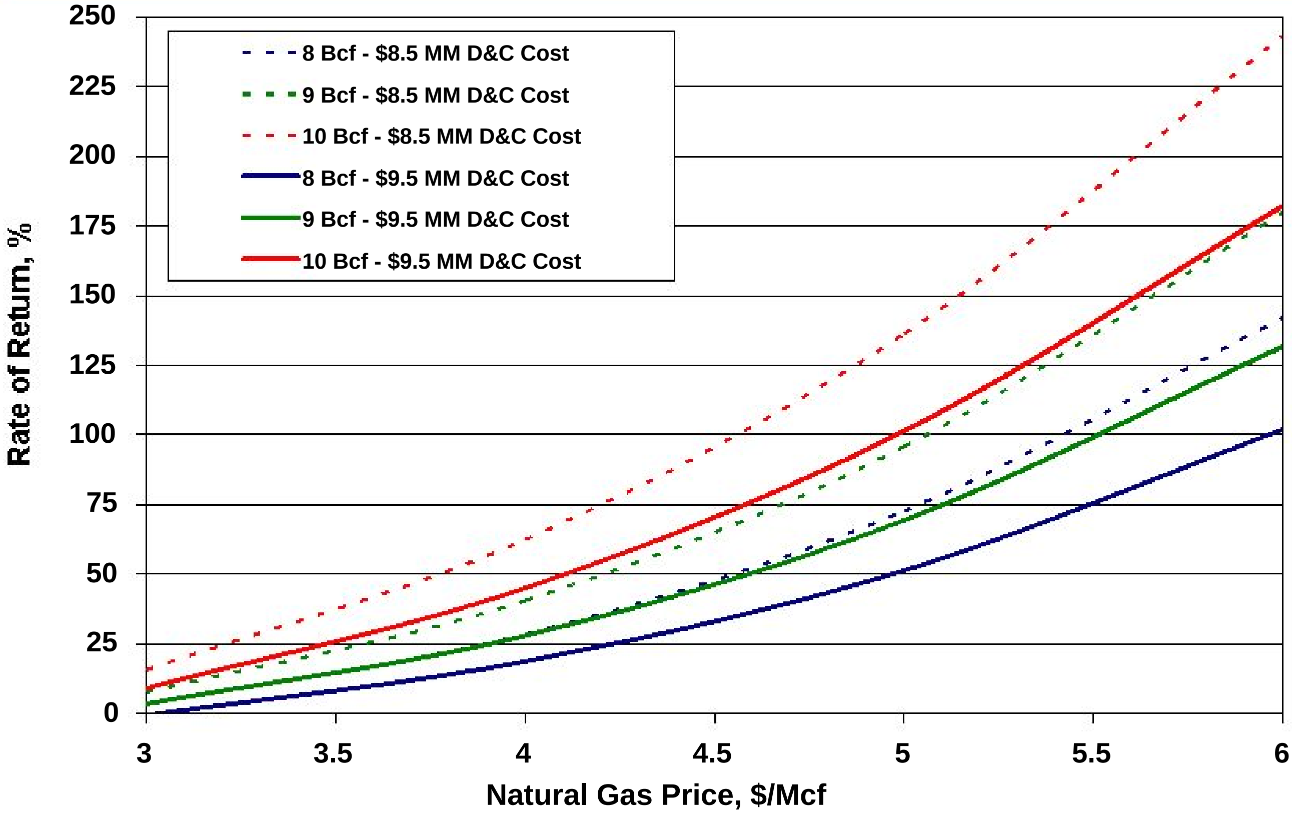
- Approximately 12,500 gross and 5,800 net acres in Haynesville Tier 1 core area
- Almost all prospective Haynesville acreage is HBP – provides “natural gas bank” for future development
- MTDR active as both operator and non-operator in Haynesville play
- Approximately 1,700 net acres with Bossier potential
- Haynesville acreage also prospective for shallower targets – Cotton Valley, Hosston – in many areas
- Approximately 10,000 net HBP acres prospective for Cotton Valley Horizontal play at Elm Grove / Caspiana



Note: Matador operates two sections, including the LA Wildlife and the BLM sections, in Tier 1; all other acreage in Tier 1 is non-operated.

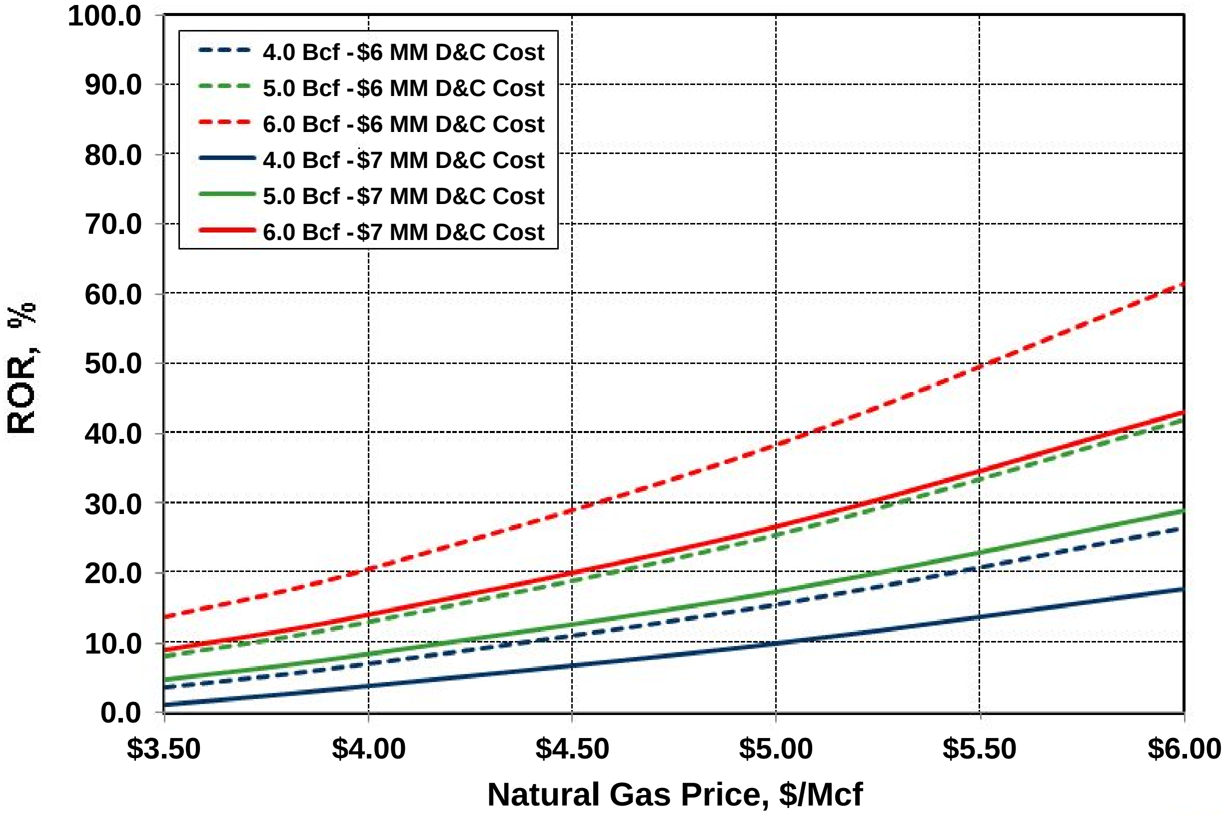
Note: All acreage at September 30, 2012; HBP = Held by production

Haynesville Well Economics – Tier 1 Area



Note: Individual well economics only. D&C cost = drilling and completion cost. Natural gas price differential = $(0.85)/Mcf.

Cotton Valley Horizontal Well Economics



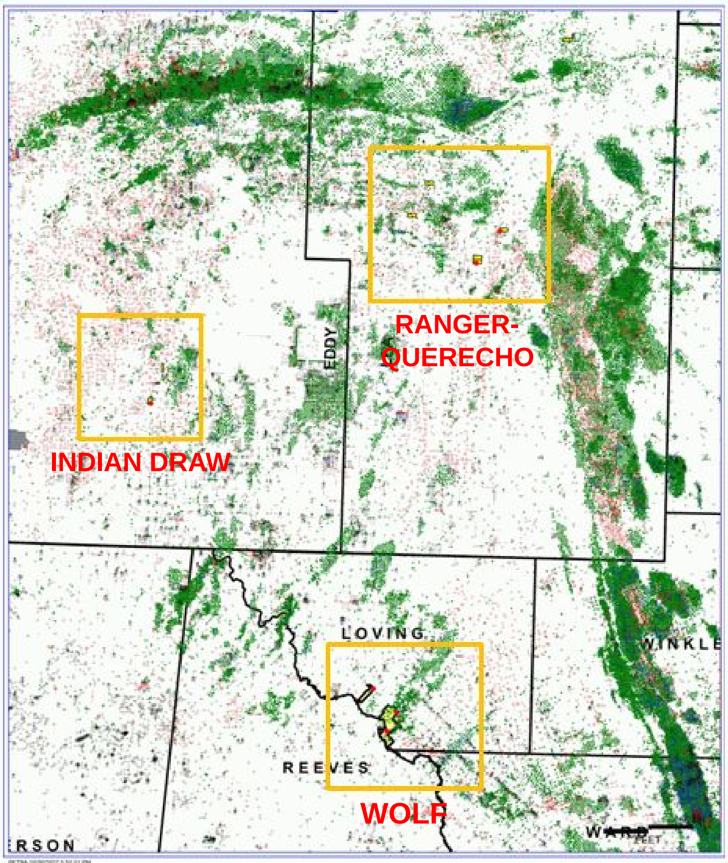
Note: Individual well economics only. D&C cost = drilling and completion cost. Natural gas price differential = -6%

Delaware Basin

Southeast New Mexico and West Texas

Southeast New Mexico / West Texas

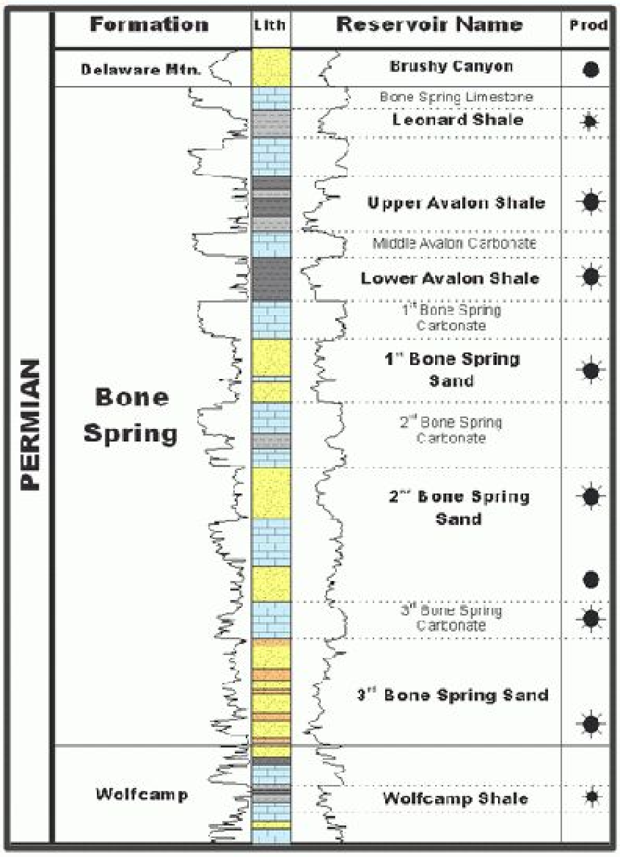


Matador Today	
Gross Acres (1)	15,528 acres
Net Acres (1)	7,534 acres

- Foothold of existing production and reserves
- On August 10, 2012, acquired approx. 4,900 gross and 2,900 net acres prospective for the Wolfbone play in the Delaware Basin in Loving County, Texas.

(1) At September 30, 2012

Wolfbone Play in the Delaware Basin (West Texas) Stratigraphic Column



Horizontal Targets

Avalon Shale
Depth: 7,900' –8,300' (Oil Window)
Density Porosity: 12-14%
Thickness: 300-500 ft.
Normal Pressure (0.45 psi/ft.)
Total Organic Carbon (TOC) 5-8%
XRD: 15-20% clay and 40-60% silica
IP: 100-270 Bbl/d 200-1,200 Mcf/d

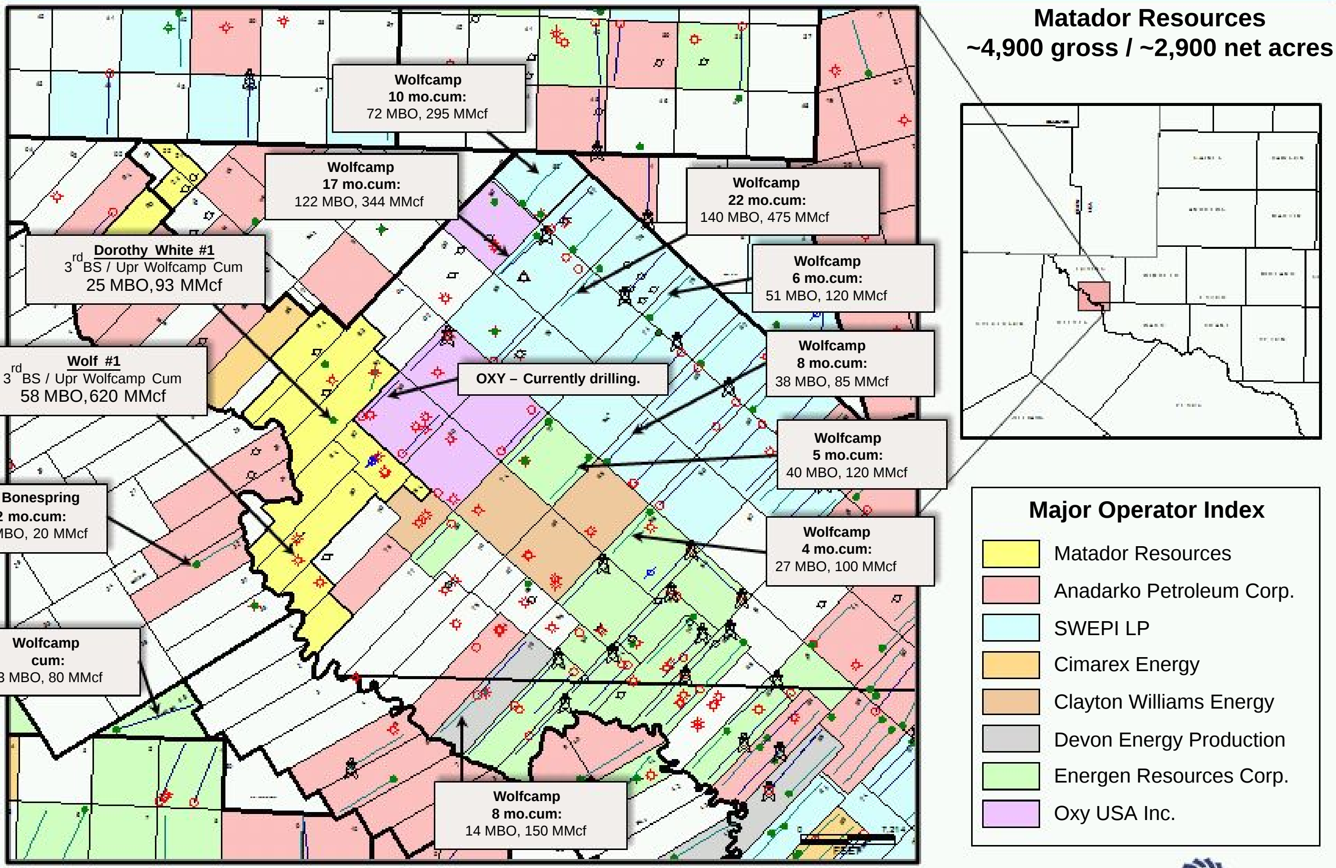
1st 2nd 3rd Bone Spring
Depth: 8,500' –10,600' (Oil Window)
Density Porosity: >10%
Thickness: 10-100 ft.
Normal Pressure (0.45 psi/ft.)
IP: 10-600 Bbl/d 500-2,500 Mcf/d

Upper Wolfcamp
Depth: 10,500' –10,600' (Oil Window)
Density Porosity: >10%
Gross Thickness: 280-350 ft.
IP: 121-900 Bbl/d 250-3,300 Mcf/d
Geopressure (0.7psi/ft.)

Middle Wolfcamp
Depth: 11,500' –12,000'
Thickness: 200-300 ft.
Total Organic Carbon (TOC) 2-4%
Density Porosity: 12-15%
Geopressure (0.7psi/ft.)

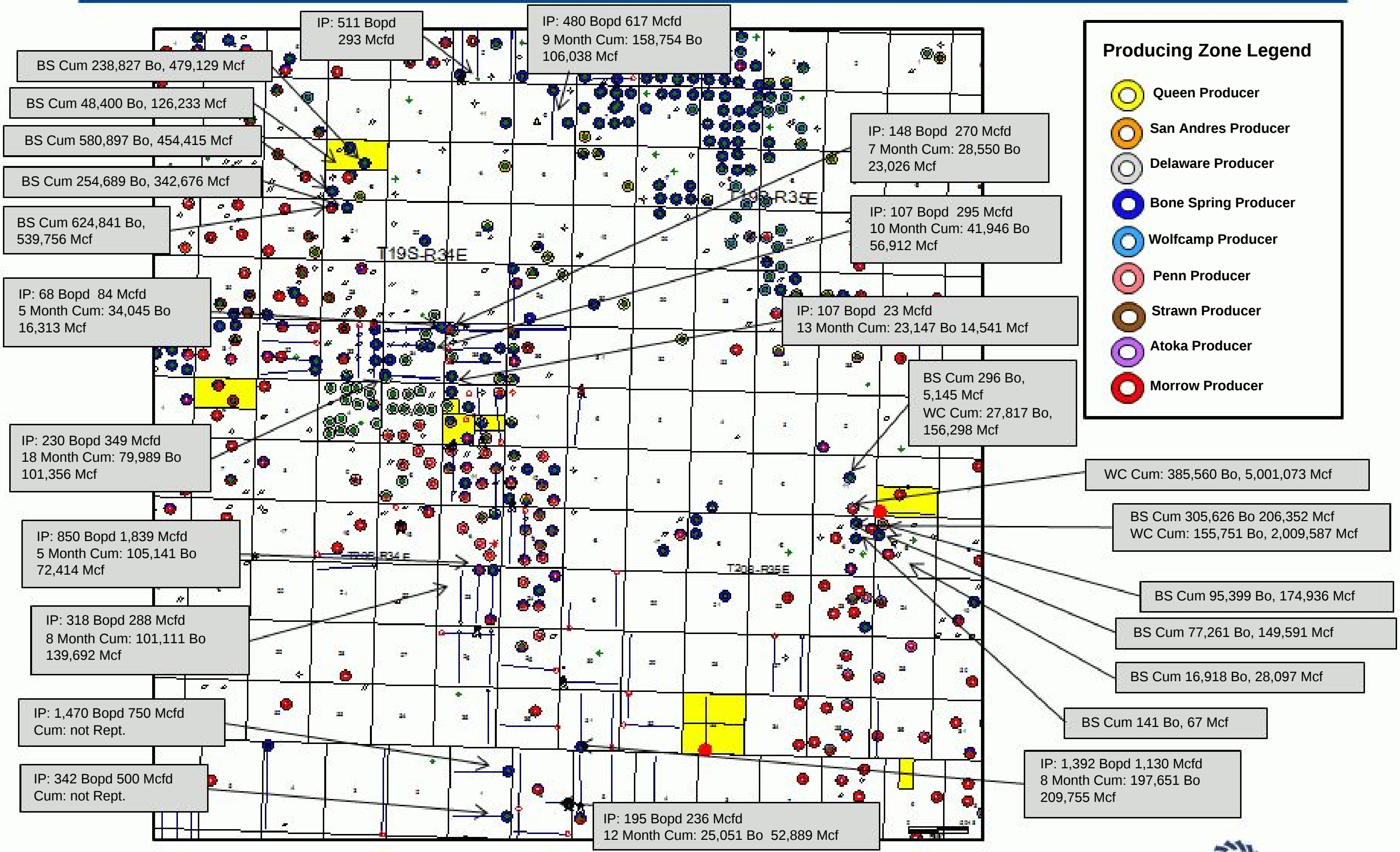
Note: Information from public sources

Wolfbone Play in the Delaware Basin (West Texas)



Note: As of November 5, 2012 and only wells with total depths greater than 7,000' posted. Third-party information from public sources.

Ranger-Querecho Prospect Area, Lea County, New Mexico: ~1,700 acres



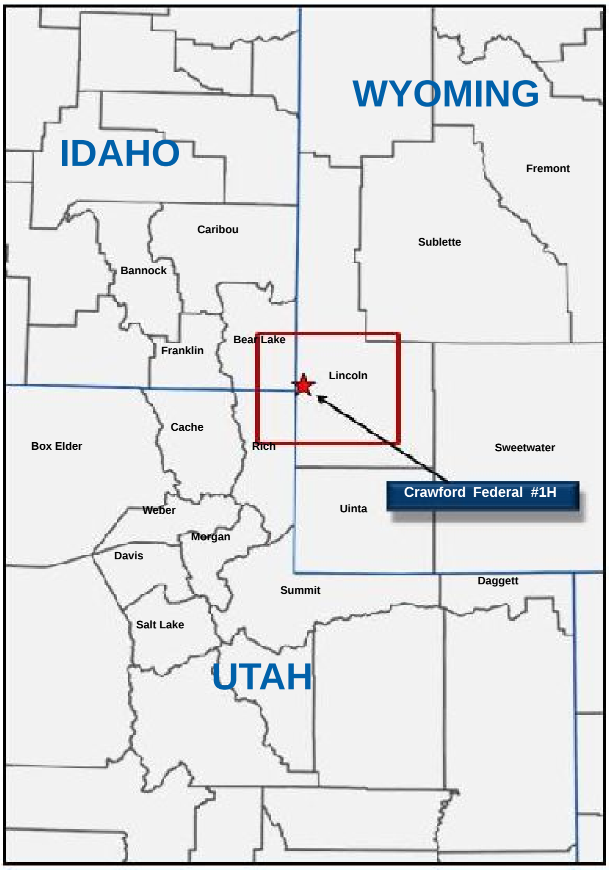
Note: Only wells with TDs greater than 7,000' posted; Well data available through public sources and interpretation by Matador Resources

Gracie

Wyoming, Utah and Idaho

Wyoming, Utah and Idaho (Meade Peak Shale)



Matador Today	
Gross Acres(1)	65,712 acres
Net Acres(1)	31,621 acres
2012E CapEx Budget	$2.5 million

- Initial test well drilled and cored through the Meade Peak shale
- Detailed petrophysical and rock property testing concluded
- Carried participation interest provided by industry partner

Matador Resources Joint Venture Area of Interest

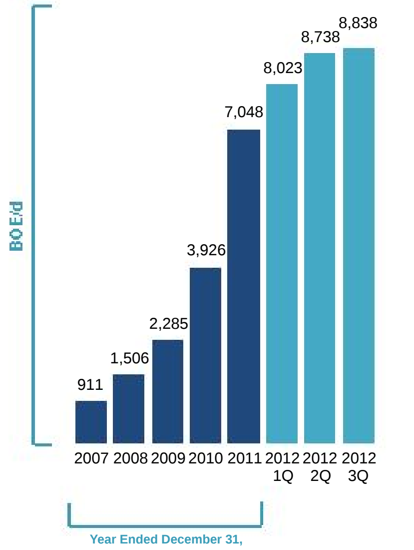
(1) At September 30, 2012



Financials

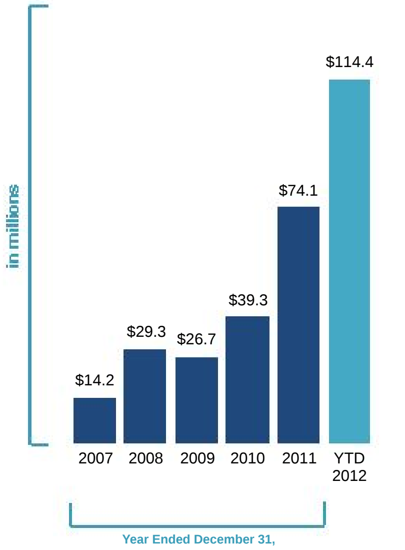
Continued Growth

AVERAGE DAILY OIL EQUIVALENT PRODUCTION

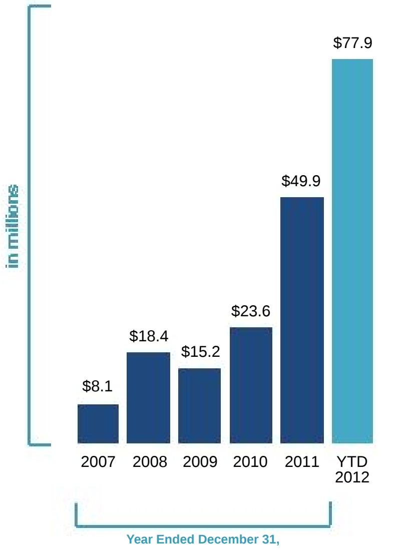


TOTAL REALIZED REVENUES

(INCLUDING REALIZED GAIN ON DERIVATIVES)



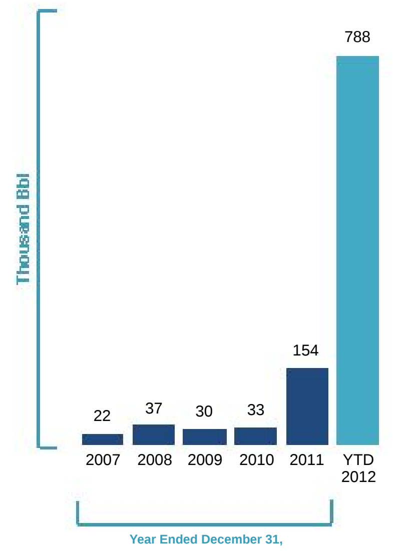
ADJUSTED EBITDA(1)



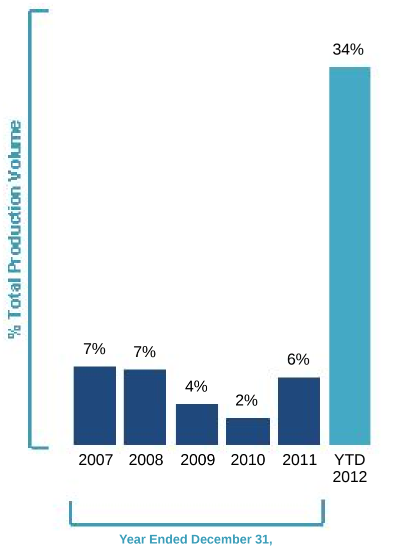
Note: YTD 2012 is through September 30, 2012
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income andnet cash provided by operating activities, see Appendix

Transition to Oil

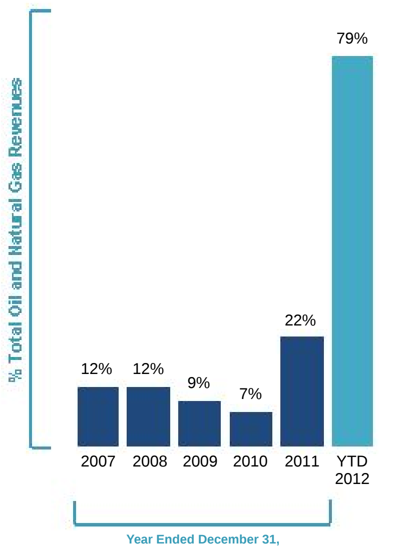
TOTAL OIL PRODUCTION



OIL BY VOLUME



OIL BY REVENUE



Note: YTD 2012 is through September 30, 2012

Recent Production and Financial Highlights

- **Record results in Q3 2012**
  - Oil production of 303,000 Bbl, a sequential quarterly increase of 6% from 285,000 Bbl produced in Q2 2012 and a year-over-year increase of 7-fold
  - 25% sequential increase in oil reserves to 8.4 million Bbl and 20% sequential increase in PV-10[1] of proved reserves to $363.6 million (Standardized Measure of $333.9 million)
  - Average daily oil equivalent production of 8,838 BOE per day, including 3,291 Bbl of oil per day and 33.3 MMcf of natural gas per day
  - Oil production of 3,291 Bbl per day, up 7-fold from 465 Bbl per day in Q3 2011; gas production of 33.3 MMcf per day down about 14% from Q3 2011 and flat to Q2 2012
  - Total realized revenues, including hedging, of $41.4 million, a year-over-year increase of 119%; oil and natural gas revenues of $38.0 million, a year-over-year increase of 118%
  - Adjusted EBITDA of $28.6 million, a year-over-year increase of 137%
- **Nine months ended September 30, 2012**
  - Total realized revenues, including hedging, of $114.4 million, a year-over-year increase of 103%; oil and natural gas revenues of $103.3 million, a year-over-year increase of 99%
  - Adjusted EBITDA of $77.9 million, a year-over-year increase of 107%

(1) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10, see Appendix

Financial Flexibility

- Funding 2012 capital budget with a portion of IPO net proceeds, cash flows from operations and available borrowings under credit facility

- Closed an amended and restated credit facility to increase the Company's borrowing capacity to $200 million primarily as a result of increased oil reserves at June 30, 2012
  - Expanded bank group to 5 banks
  - Total facility size increased from $400 million to $500 million

- Borrowing base of $200 million, increased from $125 million
  - 40% of current market capitalization[1]

- $135 million in debt outstanding as of November 9, 2012

(1) As of November 5, 2012 close

Hedging Profile

Oil Hedges (Costless Collars)	4Q 2012	FY 2013
Total Volume Hedged by Ceiling (Bbl)	360,000	1,260,000
Weighted Average Price ($ / Bbl)	$110.31	$110.26
Total Volume Hedged by Floor (Bbl)	360,000	1,260,000
Weighted Average Price ($ / Bbl)	$90.83	$87.14

Natural Gas Hedges (Costless Collars)	4Q 2012	FY 2013
Total Volume Hedged by Ceiling (Bcf)	2.31	4.65
Weighted Average Price ($ / MMBtu)	$5.30	$4.84
Total Volume Hedged by Floor (Bcf)	2.31	4.65
Weighted Average Price ($ / MMBtu)	$4.07	$3.34

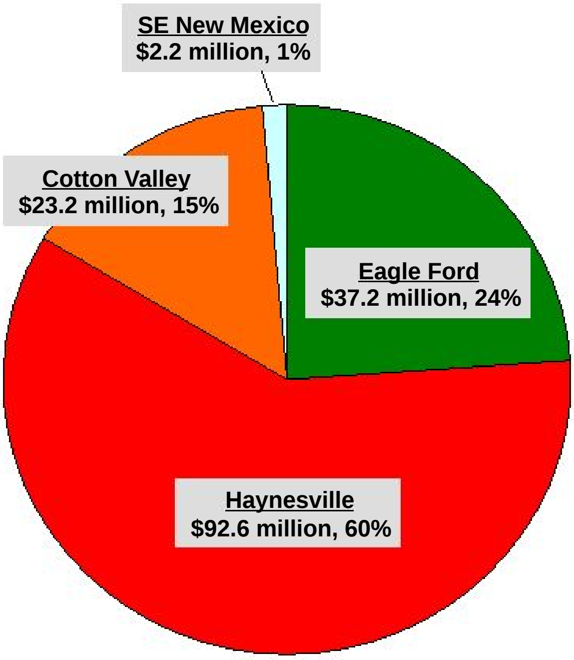
Natural Gas Liquids (NGLs) Hedges (Swaps)	4Q 2012	FY 2013
Total Volume Hedged (gal)	625,200	4,864,800
Weighted Average Price ($ / gal)	$0.81	$0.79

Reserves Summary – September 30, 2012

- Total proved reserves: 20.9 million BOE (125.4 Bcfe) at September 30, 2012, including 8.4 million Bbl of oil and 74.9 Bcf of natural gas
- Oil reserves grew 25% to 8.4 million Bbl from 6.7 million Bbl at June 30, 2012
  - Oil reserves grew 122% from December 31, 2011
- PV-10[(1)] increased 20% to $363.6 million (Standardized Measure of $333.9 million) from $303.4 million (Standardized Measure of $281.5 million) at June 30, 2012
  - PV-10[(1)] increased 46% from $248.7 million (Standardized Measure of $215.5 million) at December 31, 2011, despite removal of close to 100 Bcf of proved undeveloped Haynesville shale gas reserves at June 30, 2012
- Oil reserves comprised 40% (1 Bbl = 6 Mcf basis) of total proved reserves at September 30, 2012, up from 12% at December 31, 2011 and 4% at September 30, 2011
- Eagle Ford reserves comprised 90% of total PV-10[(1)] at September 30, 2012 as compared to 24% at September 30, 2011

(1) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10, see Appendix

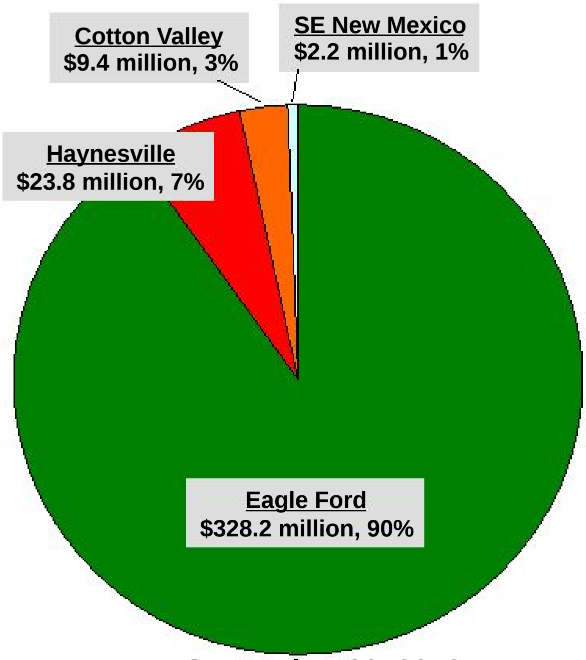
Proved Reserves Value Up Sharply and Shifting to Oil Over Past Year



September 30, 2011

PV-10[1]: $155.2 million

(Standardized Measure = $143.4 million)



September 30, 2012

PV-10[1]: $363.6 million

(Standardized Measure = $333.9 million)

(1) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10, see Appendix

Financial Statements – Quarterly Period Ended September 30, 2012

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

$4.4 million cash

	September 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,178	$ 10,284
Certificates of deposit	266	1,335
Accounts receivable		
Oil and natural gas revenues	17,046	9,237
Joint interest billings	4,252	2,488
Other	591	1,447
Derivative instruments	6,395	8,989
Lease and well equipment inventory	1,478	1,343
Prepaid expenses	974	1,153
Total current assets	35,180	36,276
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	654,292	423,945
Unproved and unevaluated	164,514	162,598
Other property and equipment	24,597	18,764
Less accumulated depletion, depreciation and amortization	(295,042)	(205,442)
Net property and equipment	548,361	399,865
Other assets		
Derivative instruments	1,880	847
Deferred income taxes	1,878	1,594
Other assets	1,537	887
Total other assets	5,295	3,328
Total assets	$ 588,836	$ 439,469

Financial Statements – Quarterly Period Ended September 30, 2012

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

	September 30, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 17,364	$ 18,841
Accrued liabilities	50,262	25,439
Royalties payable	5,920	1,855
Borrowings under Credit Agreement	-	25,000
Derivative instruments	-	171
Advances from joint interest owners	1,782	-
Income taxes payable	188	-
Deferred income taxes	1,878	3,024
Dividends payable - Class B	-	69
Other current liabilities	56	177
Total current liabilities	77,450	74,576
Long-term liabilities		
Borrowings under Credit Agreement	106,000	88,000
Asset retirement obligations	4,551	3,935
Derivative instruments	142	383
Other long-term liabilities	1,465	1,060
Total long-term liabilities	112,158	93,378
Shareholders' equity		
Common stock - Class A, $0.01 par value, 80,000,000 shares authorized; 56,697,718 and 42,916,668 shares issued; 55,502,209 and 41,737,493 shares outstanding, respectively	567	429
Common stock - Class B, $0.01 par value, zero and 2,000,000 shares authorized; zero and 1,030,700 shares issued and outstanding, respectively	-	10
Additional paid-in capital	403,248	263,562
Retained earnings	6,178	18,279
Treasury stock, at cost, 1,192,509 and 1,179,175, respectively	(10,765)	(10,765)
Total shareholders' equity	399,228	271,515
Total liabilities and shareholders' equity	$ 588,836	$ 439,469

9/30/2012 borrowings at $106 million; 11/9/12 borrowings at $135 million

Financial Statements – Quarterly Period Ended September 30, 2012

O&G Revenues
Up 118% Q3/Q3
Oil revenue = $30.1 million

2012 YTD Unit Costs
PTM = $3.25/BOE
LOE = $7.49/BOE
G&A = $4.84/BOE
DD&A = $22.58/BOE
Operating costs* = $15.58/BOE

2011 YTD Unit Costs
PTM = $2.48/BOE
LOE = $2.92/BOE
G&A = $5.13/BOE
DD&A = $11.68/BOE
Operating costs* = $10.53/BOE

Production
Up 28% Q3/Q3; up 21% YTD/YTD
Oil up 7x Q3/Q3; up 7x YTD/YTD
Gas down 14% Q3/Q3; down 15% YTD/YTD

* Operating costs defined as = PTM + LOE + G&A

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED
(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues				
Oil and natural gas revenues	$ 38,008	$ 17,447	$ 103,250	$ 52,009
Realized gain on derivatives	3,371	1,435	11,147	4,237
Unrealized (loss) gain on derivatives	(12,993)	2,870	(1,149)	1,534
Total revenues	28,386	21,752	113,248	57,780
Expenses				
Production taxes and marketing	2,822	1,848	7,605	4,801
Lease operating	6,491	2,065	17,511	5,639
Depletion, depreciation and amortization	21,680	7,288	52,799	22,578
Accretion of asset retirement obligations	59	61	170	158
Full-cost ceiling impairment	3,596	-	36,801	35,673
General and administrative	3,439	4,207	11,321	9,919
Total expenses	38,087	15,469	126,207	78,768
Operating (loss) income	(9,701)	6,283	(12,959)	(20,988)
Other income (expense)				
Net loss on asset sales and inventory impairment	-	-	(60)	-
Interest expense	(144)	(171)	(453)	(461)
Interest and other income	55	82	157	248
Total other expense	(89)	(89)	(356)	(213)
(Loss) income before income taxes	(9,790)	6,194	(13,315)	(21,201)
Income tax provision (benefit)				
Current	188	-	188	(46)
Deferred	(781)	-	(1,430)	(6,906)
Total income tax benefit	(593)	-	(1,242)	(6,952)
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)
Earnings (loss) per common share				
Basic				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B	$ -	$ 0.21	$ (0.03)	$ (0.14)
Diluted				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B	$ -	$ 0.21	$ (0.03)	$ (0.14)
Weighted average common shares outstanding				
Basic				
Class A	55,271	41,720	53,379	41,671
Class B	-	1,031	140	1,031
Total	55,271	42,751	53,519	42,702
Diluted				
Class A	55,271	41,848	53,379	41,671
Class B	-	1,031	140	1,031
Total	55,271	42,879	53,519	42,702

Financial Statements – Quarterly Period Ended September 30, 2012

EBITDA
Q3 2012 = $28.6 million
Q3 2011 = $12.1 million
EBITDA up 137% Q3/Q3

YTD 2012 = $77.9 million
YTD 2011 = $37.6 million
EBITDA up 107% Y/Y

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - UNAUDITED
(In thousands, except par value and share data)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating activities		
Net loss	$ (12,073)	$ (14,249)
Adjustments to reconcile net loss to net cash provided by operating activities		
Unrealized loss (gain) on derivatives	1,149	(1,534)
Depletion, depreciation and amortization	52,799	22,578
Accretion of asset retirement obligations	170	158
Full-cost ceiling impairment	36,801	35,673
Stock option and grant expense	(585)	1,379
Restricted stock and restricted stock units expense	362	36
Deferred income tax benefit	(1,430)	(6,906)
Loss on asset sales and inventory impairment	60	-
Changes in operating assets and liabilities		
Accounts receivable	(8,718)	(2,411)
Lease and well equipment inventory	(285)	(1)
Prepaid expenses	179	240
Other assets	(650)	-
Accounts payable, accrued liabilities and other liabilities	6,105	(2,360)
Income taxes payable	188	-
Royalties payable	4,065	2,548
Advances from joint interest owners	1,782	(723)
Other long-term liabilities	406	15
Net cash provided by operating activities	80,325	34,443
Investing activities		
Oil and natural gas properties capital expenditures	(212,702)	(104,733)
Expenditures for other property and equipment	(5,297)	(3,303)
Purchases of certificates of deposit	(416)	(3,721)
Maturities of certificates of deposit	1,485	3,985
Net cash used in investing activities	(216,930)	(107,772)
Financing activities		
Repayments of borrowings under Credit Agreement	(123,000)	-
Borrowings under Credit Agreement	116,000	60,000
Proceeds from issuance of common stock	146,510	592
Swing sale profit contribution	24	-
Cost to issue equity	(11,599)	(1,185)
Proceeds from stock options exercised	2,660	837
Payment of dividends - Class B	(96)	(206)
Net cash provided by financing activities	130,499	60,038
Decrease in cash and cash equivalents	(6,106)	(13,291)
Cash and cash equivalents at beginning of period	10,284	21,059
Cash and cash equivalents at end of period	$ 4,178	$ 7,768

Total CAPEX incurred at 9/30/12
$237.6 million
76% of 2012 budget

Includes $21.2 million acreage

Statements of Operations - Selected Quarterly Periods in 2012 and 2011

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED

(In thousands, except per share data)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Revenues						
Oil and natural gas revenues	$ 38,008	$ 17,447	$ 36,078	$ 20,864	$ 29,164	$ 13,698
Realized gain on derivatives	3,371	1,435	4,713	952	3,063	1,850
Unrealized (loss) gain on derivatives	(12,993)	2,870	15,114	332	(3,270)	(1,668)
Total revenues	28,386	21,752	55,905	22,148	28,957	13,880
Expenses						
Production taxes and marketing	2,822	1,848	2,619	1,654	2,164	1,300
Lease operating	6,491	2,065	6,375	1,969	4,645	1,605
Depletion, depreciation and amortization	21,680	7,288	19,913	8,179	11,206	7,111
Accretion of asset retirement obligations	59	61	58	57	53	39
Full-cost ceiling impairment	3,596	-	33,205	-	-	35,673
General and administrative	3,439	4,207	4,093	3,094	3,789	2,619
Total expenses	38,087	15,469	66,263	14,953	21,857	48,347
Operating (loss) income	(9,701)	6,283	(10,358)	7,195	7,100	(34,467)
Other income (expense)						
Net loss on asset sales and inventory impairment	-	-	(60)	-	-	-
Interest expense	(144)	(171)	(1)	(183)	(308)	(106)
Interest and other income	55	82	30	94	73	71
Total other expense	(89)	(89)	(31)	(89)	(235)	(35)
(Loss) income before income taxes	(9,790)	6,194	(10,389)	7,106	6,865	(34,502)
Income tax provision (benefit)						
Current	188	-	-	(46)	-	-
Deferred	(781)	-	(3,713)	-	3,064	(6,906)
Total income tax benefit (provision)	(593)	-	(3,713)	(46)	3,064	(6,906)
Net (loss) income	$ (9,197)	$ 6,194	$ (6,676)	$ 7,152	$ 3,801	$ (27,596)
Earnings (loss) per common share						
Basic						
Class A	$ (0.17)	$ 0.14	$ (0.12)	$ 0.17	$ 0.08	$ (0.65)
Class B	$ -	$ 0.21	$ -	$ 0.23	$ 0.15	$ (0.58)
Diluted						
Class A	$ (0.17)	$ 0.14	$ (0.12)	$ 0.17	$ 0.08	$ (0.65)
Class B	$ -	$ 0.21	$ -	$ 0.23	$ 0.15	$ (0.58)
Weighted average common shares outstanding						
Basic						
Class A	55,271	41,720	55,271	41,667	49,597	41,624
Class B	-	1,031	-	1,031	419	1,031
Total	55,271	42,751	55,271	42,698	50,016	42,655
Diluted						
Class A	55,271	41,848	55,271	41,782	49,666	41,624
Class B	-	1,031	-	1,031	419	1,031
Total	55,271	42,879	55,271	42,813	50,085	42,655

Appendix

Board of Directors and Special Board Advisors – Expertise and Stewardship

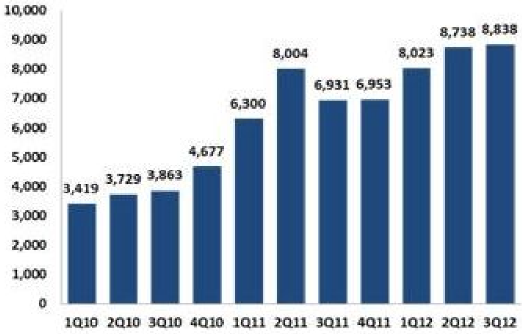
Board Members and Advisors	Professional Experience	Business Expertise
Dr. Stephen A. Holditch Director	- Professor and Former Head of Dept. of Petroleum Engineering, Texas A&M University - Founder / President S.A. Holditch & Associates - Past President of Society of Petroleum Engineers	Oil & Gas Operations
David M. Laney Director	- Past Chairman, Amtrak Board of Directors - Former Partner, Jackson Walker LLP	Law
Gregory E. Mitchell Director	- President / CEO, Toot'n Totum Food Stores	Petroleum Retailing
Dr. Steven W. Ohnimus Director	- Retired VP and General Manager, Unocal Indonesia	Oil & Gas Operations
Michael C. Ryan Director	- Partner, Berens Capital Management	International Business and Finance
Margaret B. Shannon Director	- Retired VP and General Counsel, BJ Services Co. - Former Partner, Andrews Kurth LLP	Law and Corporate Governance
Mino Capossela Special Board Advisor	- Retired partner Goldman Sachs; Charter Financial Analyst; Private Investor	Finance and Management
Marlan W. Downey Special Board Advisor	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil & Gas Exploration
Wade I. Massad Special Board Advisor	- Managing Member, Cleveland Capital Management, LLC - Former EVP Capital Markets, Matador Resources Company - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Edward R. Scott, Jr. Special Board Advisor	- Former Chairman, Amarillo Economic Development Corporation - Law Firm of Gibson, Ochsner & Adkins	Law, Accounting and Real Estate Development
W.J. "Jack" Sleeper, Jr. Special Board Advisor	- Retired President, DeGolyer and MacNaughton (Worldwide Petroleum Consultants)	Oil & Gas Executive Management

Proven Management Team – Experienced Leadership

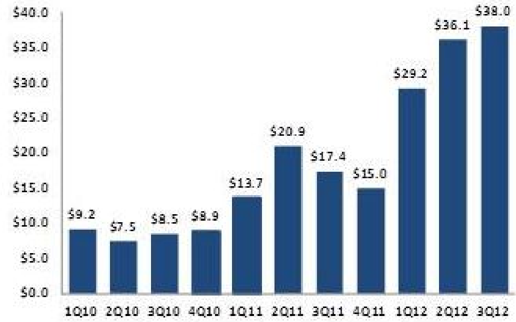
Management Team	Background and Prior Affiliations	Industry Experience	Matador Experience
Joseph Wm. Foran Founder, Chairman and CEO	- Matador Petroleum Corporation, Foran Oil Company, J Cleo Thompson Jr. and Thompson Petroleum Corp.	32 years	Since Inception
David E. Lancaster EVP and COO	- Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	33 years	Since 2003
Matthew V. Hairford EVP and Head of Operations	- Samson, Sonat, Conoco	28 years	Since 2004
David F. Nicklin Executive Director of Exploration	- ARCO, Senior Geological Assignments in UK, Angola, Norway and the Middle East	41 years	Since 2007
Bradley M. Robinson VP, Reservoir Engineering	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	35 years	Since Inception
Craig N. Adams VP and General Counsel	- Baker Botts L.L.P., Thompson & Knight LLP	20 years	Since 2012
Kathryn L. Wayne Controller and Treasurer	- Matador Petroleum Corporation, Mobil	28 years	Since Inception
Ryan London Senior Completion Engineer Eagle Ford Asset Manager	- Matador Resources Company	9 years	Since 2003

Quarterly Performance Metrics Through Q3 2012

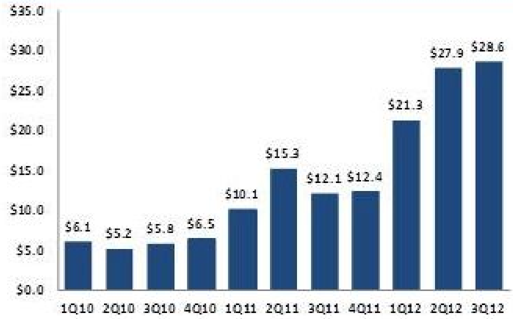
Average Daily Equivalent Production
(BOE/d)



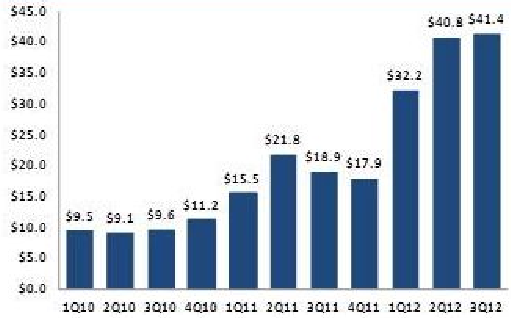
Oil and Natural Gas Revenues
($ in mm)



Adjusted EBITDA (1)
($ in mm)

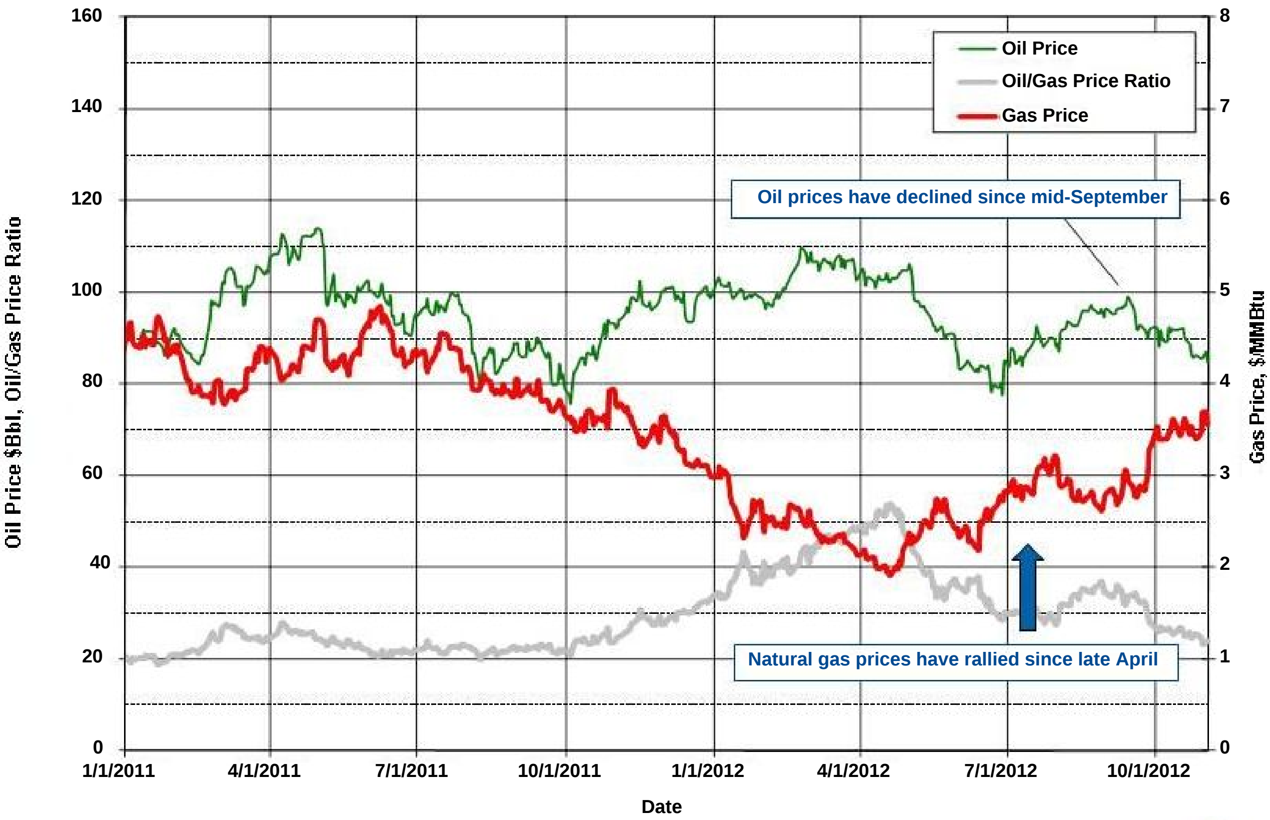


Total Realized Revenues
($ in mm)



(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix

Oil and Natural Gas Prices Since January 2011



Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net (loss) income and cash provided by operating activities, respectively.

(In thousands)	Year Ended December 31,					Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2012
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):						
Net (loss) income	($300)	$103,878	($14,425)	$6,377	($10,309)	($8,568)
Interest expense	-	-	-	3	683	453
Total income tax provision (benefit)	-	20,023	(9,925)	3,521	(5,521)	(1,152)
Depletion, depreciation and amortization	7,889	12,127	10,743	15,596	31,754	52,799
Accretion of asset retirement obligations	70	92	137	155	209	170
Full-cost ceiling impairment	-	22,195	25,244	-	35,673	33,206
Unrealized loss (gain) on derivatives	211	(3,592)	2,375	(3,139)	(5,138)	1,149
Stock option and grant expense	205	605	622	824	2,362	(585)
Restricted stock grants	15	60	34	74	44	362
Net loss (gain) on asset sales and inventory impairment	-	(136,977)	379	224	154	60
Adjusted EBITDA	**$8,090**	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$77,894**

(In thousands)	Year Ended December 31,					Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2012
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:						
Net cash provided by operating activities	$7,881	$25,851	$1,791	$27,273	$61,868	$80,325
Net change in operating assets and liabilities	209	(17,888)	15,717	(2,230)	(12,594)	(3,072)
Interest expense	-	-	-	3	683	453
Current income tax provision (benefit)	-	10,448	(2,324)	(1,411)	(46)	188
Adjusted EBITDA	**$8,090**	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$77,894**

We believe Adjusted EBITDA helps us evaluate our operating performance and compare our results of operation from period to period without regard to our financing methods or capital structure. We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock units expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net (loss) income or cash flows as determined by GAAP. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity.

Adjusted EBITDA Reconciliation (Cont.)

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net (loss) income and cash provided by operating activities, respectively.

(In thousands)	1Q 2010	2Q 2010	3Q 2010	4Q 2010	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):											
Net income (loss)	$ 5,676	$ (984)	$ 2,681	$ (996)	$ (27,596)	$ 7,153	$ 6,194	$ 3,941	$ 3,801	$ (6,676)	$ (9,197)
Interest expense	-	-	-	3	106	184	171	222	308	1	144
Total income tax provision (benefit)	2,975	(516)	1,584	(522)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)
Depletion, depreciation and amortization	3,362	3,702	3,868	4,665	7,111	8,180	7,287	9,175	11,205	19,914	21,680
Accretion of asset retirement obligations	38	30	39	48	39	57	62	51	53	58	59
Full-cost ceiling impairment	-	-	-	-	35,673	-	-	-	-	33,205	3,596
Unrealized (gain) loss on derivatives	(6,093)	2,822	(2,541)	2,674	1,668	(332)	(2,870)	(3,604)	3,270	(15,114)	12,993
Stock option and grant expense	180	153	133	357	42	117	1,220	983	(374)	41	(252)
Restricted stock grants	6	8	11	49	11	11	14	8	11	150	201
Net (gain)/loss on asset sales and inventory impairment	-	-	-	224	-	-	-	154	-	60	-
Adjusted EBITDA	**$ 6,142**	**$ 5,215**	**$ 5,776**	**$ 6,502**	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,360**	**$ 21,338**	**$ 27,926**	**$ 28,631**

(In thousands)	1Q 2010	2Q 2010	3Q 2010	4Q 2010	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:											
Net cash provided by operating activities	$ 7,673	$ 29,040	$ (15,322)	$ 5,883	$ 12,732	$ 6,799	$ 14,912	$ 27,425	$ 5,110	$ 46,416	$ 28,799
Net change in operating assets and liabilities	(1,531)	(23,824)	22,509	616	(2,690)	8,386	(3,004)	(15,287)	15,920	(18,491)	(500)
Interest expense	-	-	-	3	106	184	171	222	308	1	144
Current income tax (benefit) provision	-	-	(1,411)	-	-	(45)	(1)	-	-	- `	188
Adjusted EBITDA	**$ 6,142**	**$ 5,215**	**$ 5,776**	**$ 6,502**	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,360**	**$ 21,338**	**$ 27,926**	**$ 28,631**

We believe Adjusted EBITDA helps us evaluate our operating performance and compare our results of operation from period to period without regard to our financing methods or capital structure. We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock units expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net (loss) income or cash flows as determined by GAAP. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity.

PV-10 Reconciliation

PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. Matador and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. The PV-10 at September 30, 2012, December 31, 2011 and September 30, 2011 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at September 30, 2012, December 31, 2011 and September 30, 2011 were, in millions, $29.7, $33.2 and $11.8, respectively.