EAGLE ROCK
ENERGY PARTNERS, L.P.

Building on Our Core

Wells Fargo 2011 Pipeline, MLP, and E&P, Services & Utility Symposium

December 2011

Forward Looking Statements

This document may include "forward-looking statements." All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the Partnership expects, believes or anticipates will or may occur in the future are forward-looking statements and speak only as of the date on which such statement is made. These statements are based on certain assumptions made by the Partnership based on its experience and perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate under the circumstances. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Partnership. These include risks related to volatility of commodity prices; market demand for natural gas and natural gas liquids; the effectiveness of the Partnership's hedging activities; the Partnership's ability to retain key customers; the Partnership's ability to continue to obtain new sources of natural gas supply; the availability of local, intrastate and interstate transportation systems and other facilities to transport natural gas and natural gas liquids; competition in the oil and gas industry; the Partnership's ability to obtain credit and access the capital markets; general economic conditions; and the effects of government regulations and policies. Should one or more of these risks or uncertainties occur, or should underlying assumptions prove incorrect, the Partnership's actual results and plans could differ materially from those implied or expressed by any forward-looking statements. The Partnership assumes no obligation to update any forward-looking statement as of any future date. For a detailed list of the Partnership's risk factors, please consult the Partnership's Form 10-K, filed with the Securities and Exchange Commission ("SEC") for the year ended December 31, 2010, the Partnership's Forms 10-Q, filed with the SEC for subsequent quarters, as well as any other public filings and press releases.

Management Representatives

Joseph A. Mills

Chairman & Chief Executive Officer

Jeffrey P. Wood

Senior Vice President & Chief Financial Officer

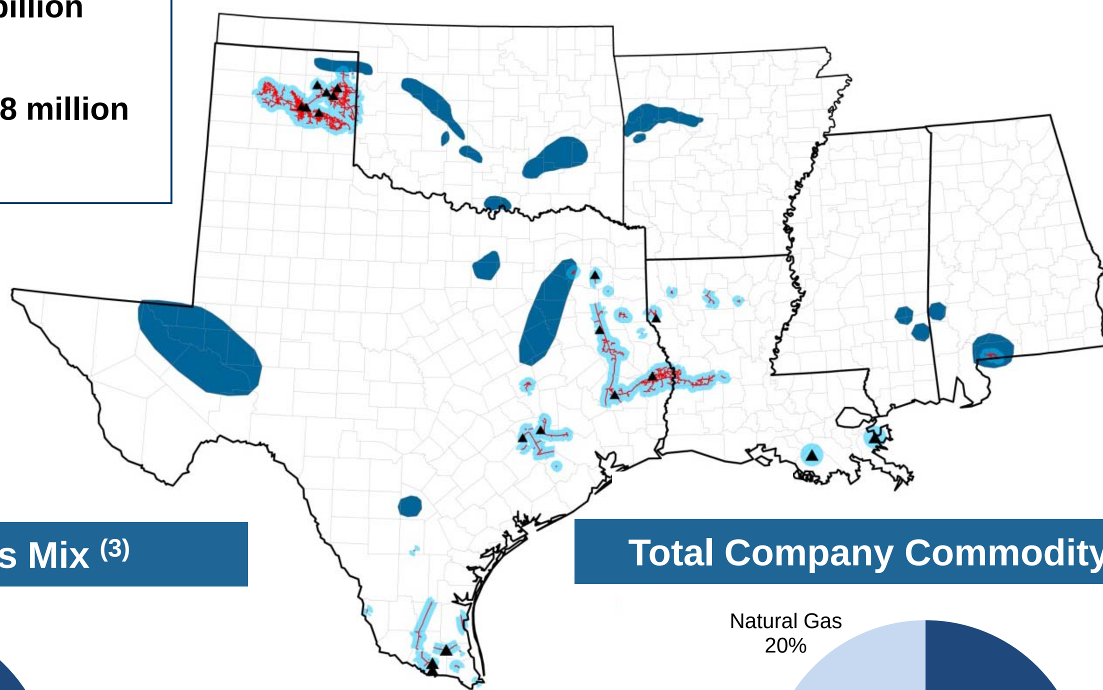
Adam K. Altsuler

Director, Corporate Finance & Investor Relations

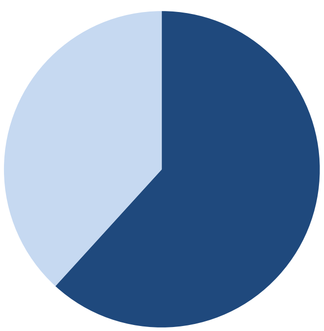
Eagle Rock Energy Partners, L.P. Snapshot

- Eagle Rock (NASDAQ: EROC) is a growth-oriented MLP engaged in the midstream and upstream businesses and is well-positioned to benefit from some of the most prolific producing basins in the U.S.

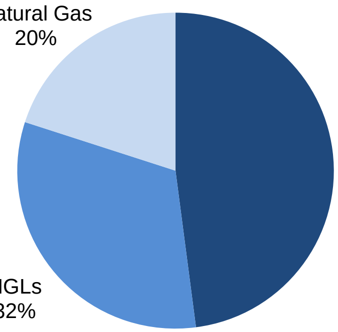
Enterprise Value[(1)]:	**$2.1 billion**
Annualized Adj. EBITDA[(2)]:	**$248.8 million**
Q3 Leverage Ratio:	**3.2x**



Estimated Business Mix [(3)]



Total Company Commodity Mix [(4)]



(1) Equity value includes common units and warrants priced at their respective prices as of 11/29/11.
(2) Calculated based on 3 months ended 9/30/11 Adjusted EBITDA times 4.
(3) Based on segment operating income plus DD&A for the LTM ended 9/30/11 and excluding G&A.
(4) Based on 9/30/11 LTM gross margin based on net equity volumes from Midstream Business and production volumes from Upstream Business and weighted average received prices for respective business segments and periods. Adjusted for Eustace processing facility shut-down and pro forma for Mid-Continent acquisition.

Strategically Located, Diversified Asset Base

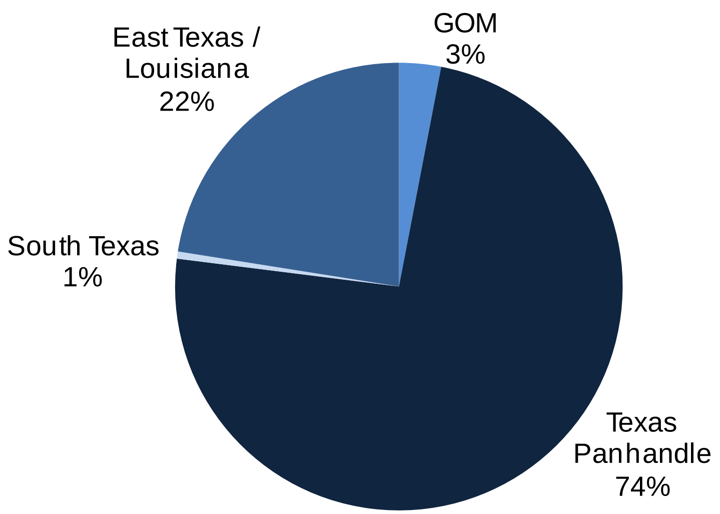
Midstream Business (1)

- 5,482 miles of pipeline
- 19 processing plants
- 476 MMcf/d gathering volumes
- 6.7 MBbls/d equity NGLs / Condensate

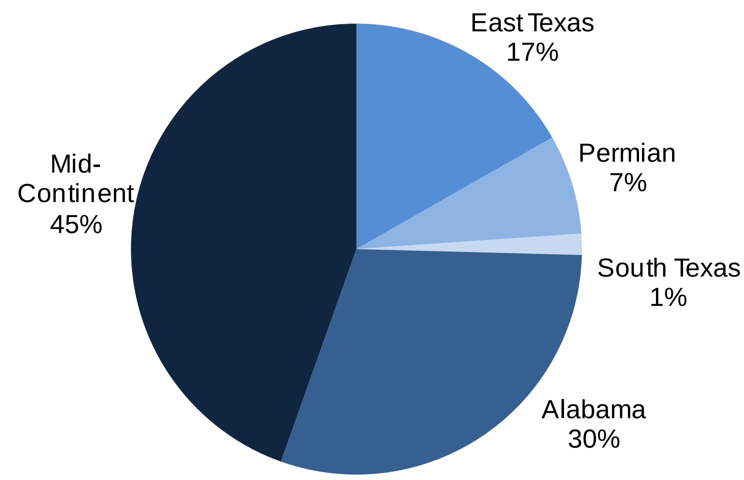
Upstream Business (2)

- 600 operated producing wells
- 385 Bcfe proved reserves
- 81.1 MMcfe/d net production
- 63% natural gas by reserves

Midstream Business Mix (3)



Upstream Business Mix (3)



(1) Based on Q3 2011.
(2) Pro forma reserves as of 12/31/10 based on SEC pricing as of 12/31/10. Net production based on Q3 average production.
(3) Based on Q3 2011 operating income plus DD&A, excluding G&A and hedging impact.

Delivering on Our Strategic Objectives

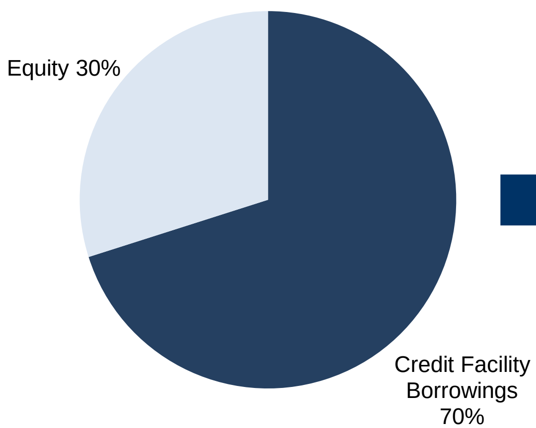
Objective		Status
➢ **Create Platform to Grow Organically**	✓	• Recently announced Midstream projects capitalize on existing infrastructure • Upstream properties contain over 680 gross identified drilling locations
➢ **Deliver Outstanding Service to Our Midstream Producer Customers**	✓	• Adding new processing capacity in Granite Wash to accommodate growing volumes
➢ **Enhance Liquidity and Balance Sheet Stability**	✓	• Over $225 million of liquidity on credit facility at September 30, 2011 • New $675 million credit facility put in place in May 2011 with 2016 maturity • Inaugural senior notes issuance of $300 million completed in May 2011
➢ **Mitigate Commodity Exposure**	✓	• Extensive hedging program covering approximately 80% of near-term volumes and extending through 2014 • Majority of near-term NGL volumes hedged directly by product

Positioning for Further Growth

Eagle Rock Has Substantially Improved Its Liquidity and Balance Sheet Stability [1]

September 30, 2009

Enterprise Value: $1.1 billion



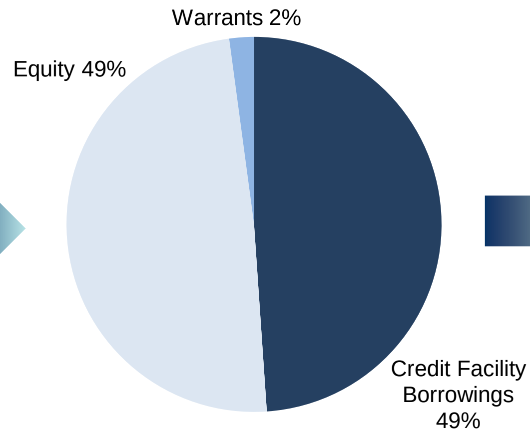
Credit Facility Availability : ~$34 million

3-Mo. Avg. Daily Trading Value:

~$1.7 million

September 30, 2010

Enterprise Value: $1.1 billion



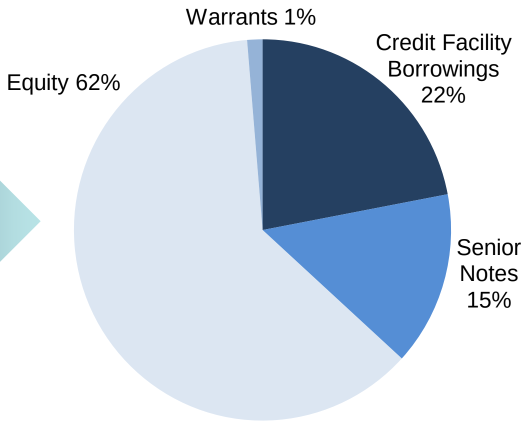
Credit Facility Availability : ~$157 million

3-Mo. Avg. Daily Trading Value:

~$1.8 million

September 30, 2011

Enterprise Value: $2.0 billion



Credit Facility Availability : ~$228 million

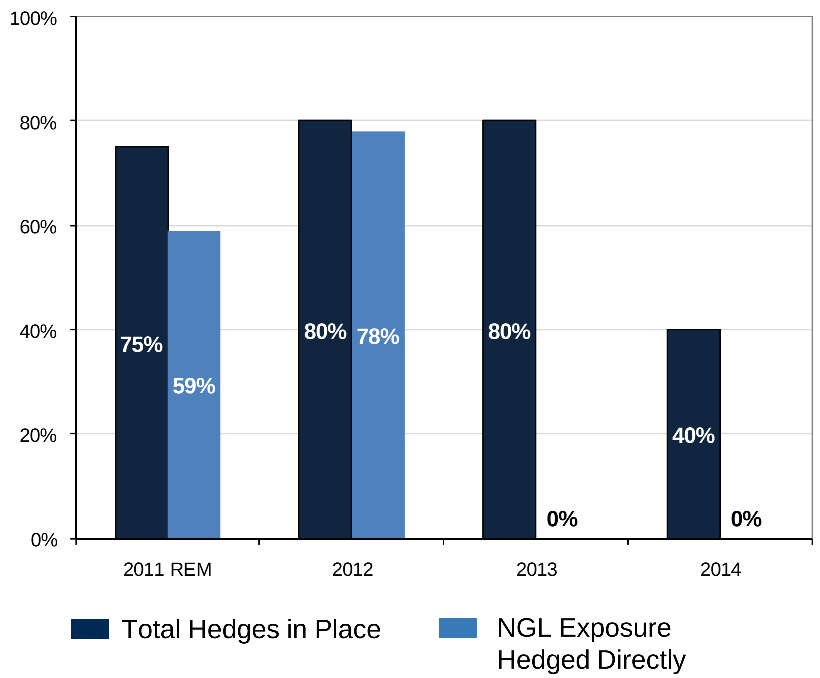
3-Mo. Avg. Daily Trading Value:

~$3.5 million

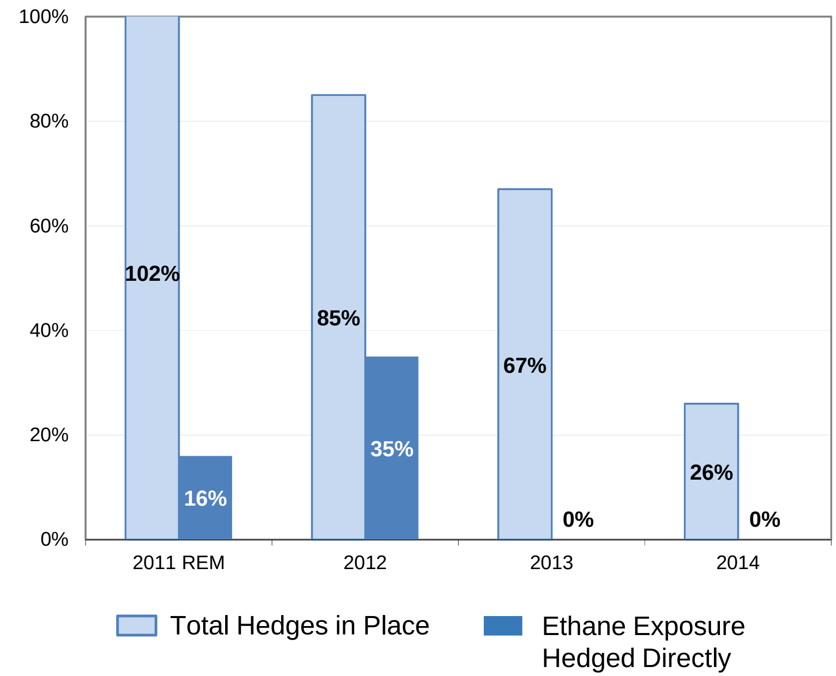
(1) Equity value includes common units and warrants priced at their respective prices as of the respective periods.

Robust Hedging Profile

Crude, Condensate and NGLs (>C2)



Ethane and Natural Gas



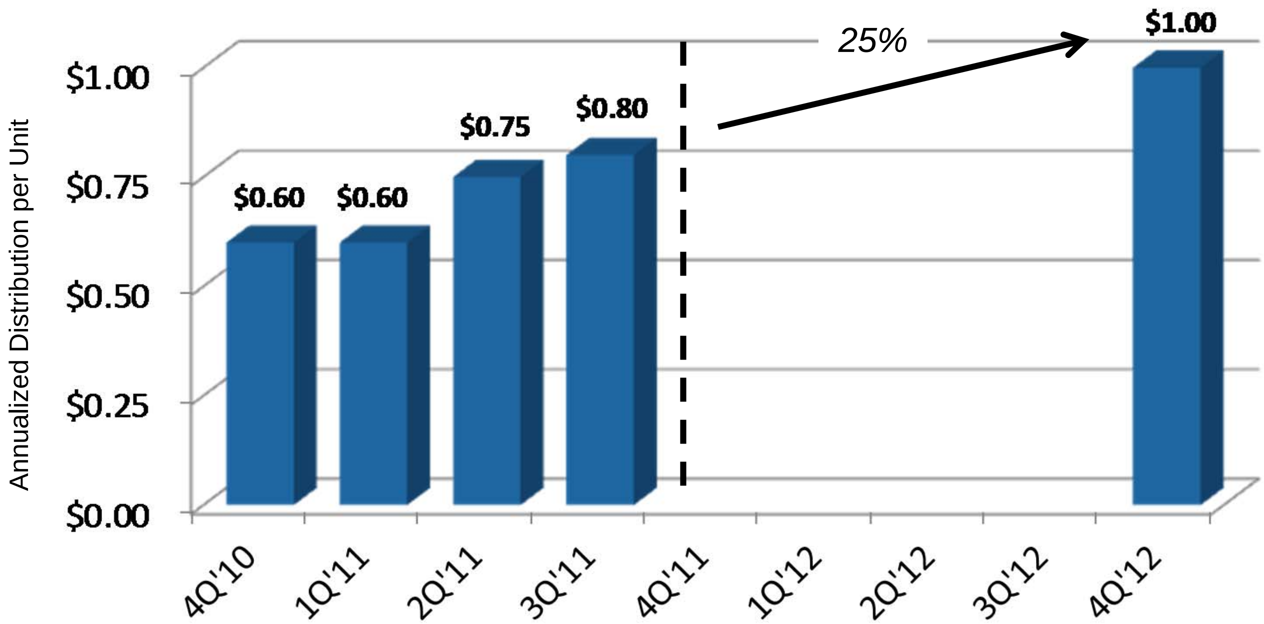
Avg. Strike Price (1)	**$75.23**	**$80.05**	**$96.66**	**$97.36**	**$5.96**	**$5.87**	**$5.22**	**$5.55**

(1) Prices shown reflect weighted average price of swaps and collar floors ($/Bbl and $/MMBtu) and exclude price impact of direct product hedges.

Delivering Value to Our Unitholders

Improved Growth Profile and Capitalization Lead to Greater Unitholder Value

Current Annualized Distribution Guidance **



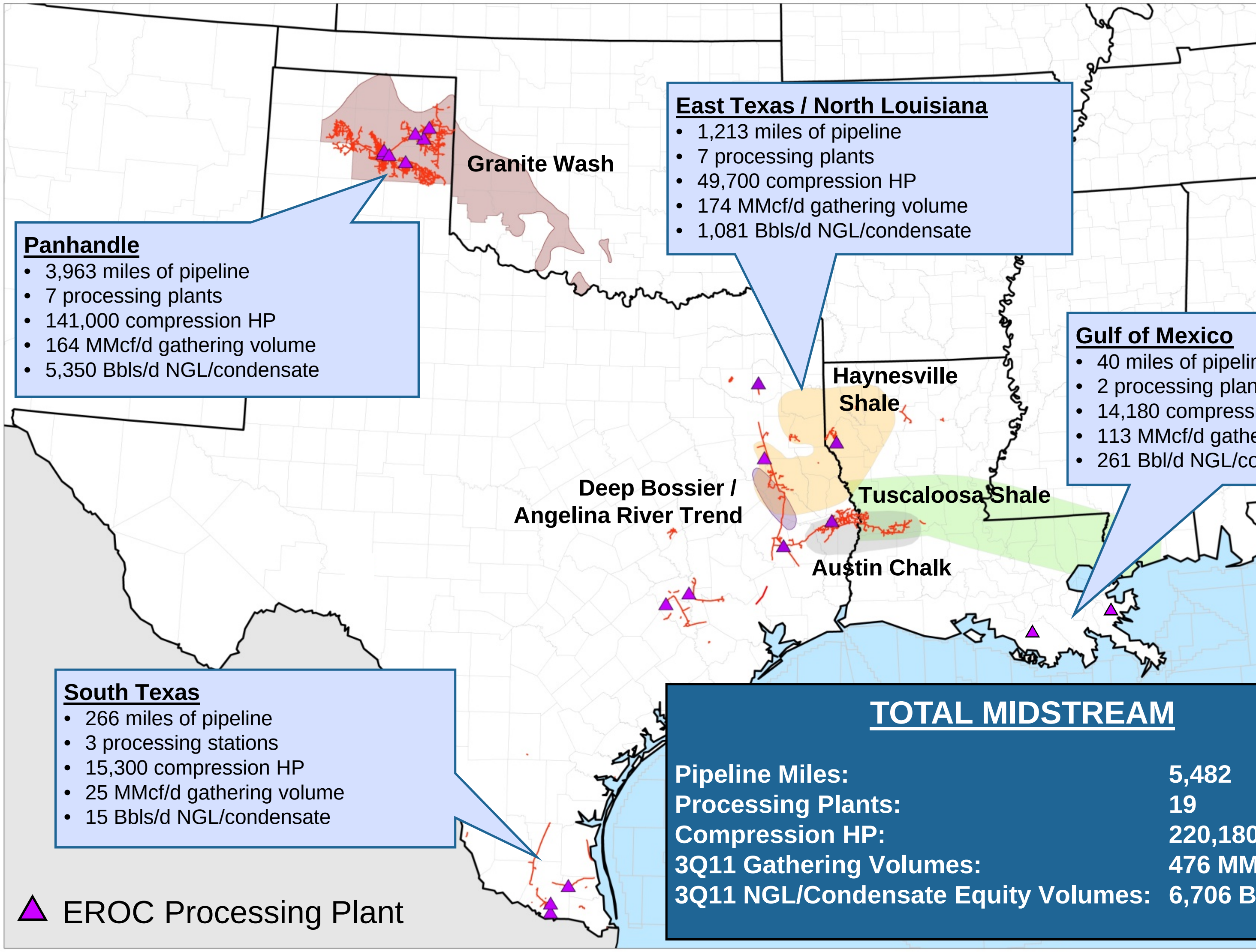
** Management's intentions around future distribution recommendations are subject to change, however, should factors affecting the general business climate, market conditions, commodity prices, the Partnership's specific operations, performance of the Partnership's underlying assets, applicable regulatory mandates, or the Partnership's ability to consummate accretive growth projects differ from current expectations.

Eagle Rock Energy Partners, L.P.

Midstream Business Overview

Wells Fargo Pipeline / MLP Symposium *December 2011*

Geographically Diverse Midstream Business



Panhandle
- 3,963 miles of pipeline
- 7 processing plants
- 141,000 compression HP
- 164 MMcf/d gathering volume
- 5,350 Bbls/d NGL/condensate

East Texas / North Louisiana
- 1,213 miles of pipeline
- 7 processing plants
- 49,700 compression HP
- 174 MMcf/d gathering volume
- 1,081 Bbls/d NGL/condensate

Gulf of Mexico
- 40 miles of pipeline
- 2 processing plants
- 14,180 compression HP
- 113 MMcf/d gathering volume
- 261 Bbl/d NGL/condensate

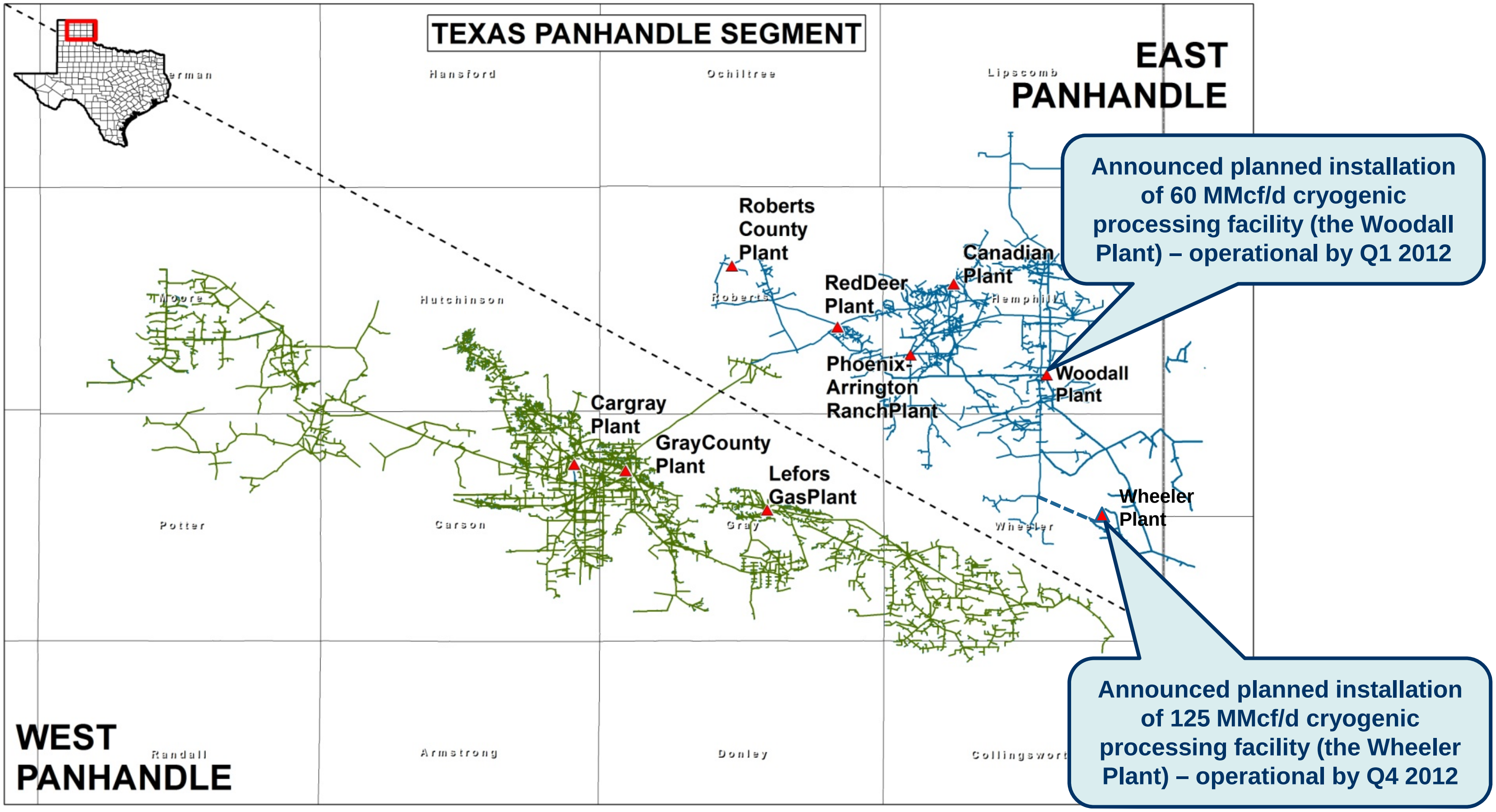
South Texas
- 266 miles of pipeline
- 3 processing stations
- 15,300 compression HP
- 25 MMcf/d gathering volume
- 15 Bbls/d NGL/condensate

TOTAL MIDSTREAM

Pipeline Miles:	**5,482**
Processing Plants:	**19**
Compression HP:	**220,180**
3Q11 Gathering Volumes:	**476 MMcf/d**
3Q11 NGL/Condensate Equity Volumes:	**6,706 Bbls/d**

Note: Based on Q3 2011.

Panhandle System



West Panhandle:

- Liquids-rich production from Brown Dolomite formation
  - 8+ GPM gas
- Low decline production (6-7% annually)

East Panhandle:

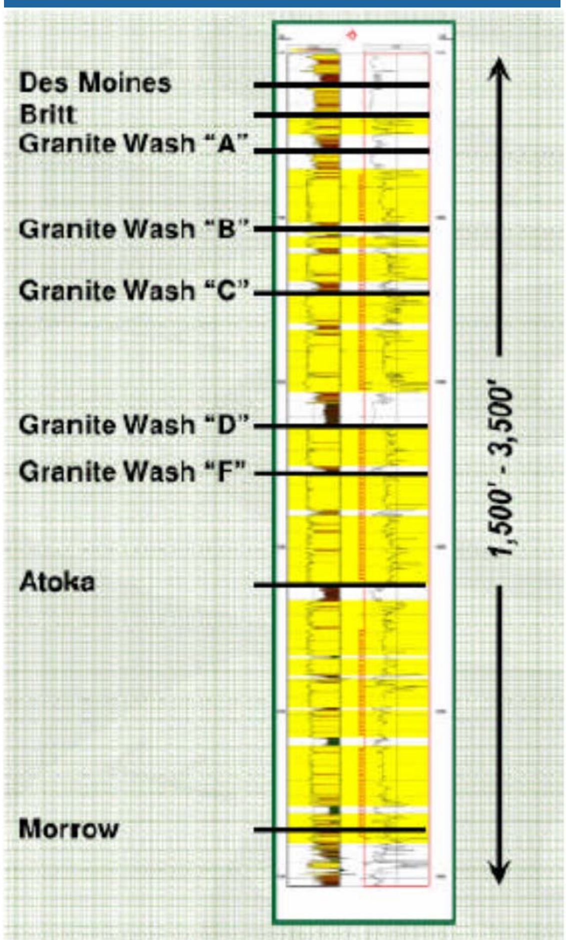
- Liquids-rich production from Granite Wash play (4-6 GPM gas)
- Eagle Rock system well-positioned in one of the most active plays in the U.S.

Proposed new gathering line

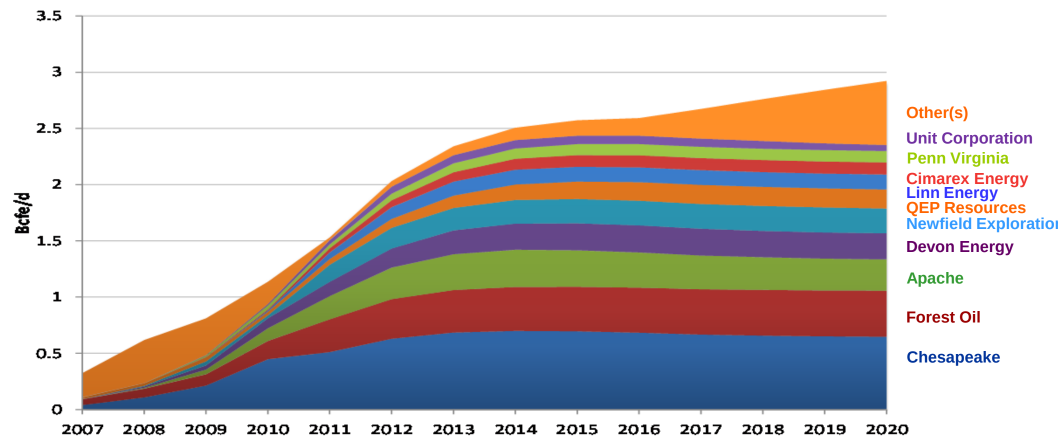
Leading Midstream Company in the Granite Wash

Superior Economics Driving Production Growth

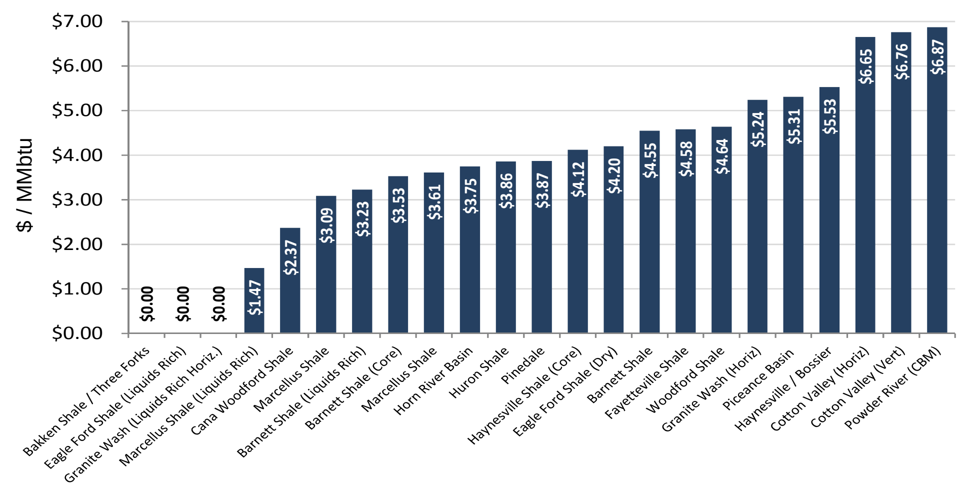
Stacked Pay Zones Improve Economics



Granite Wash Daily Production (1)



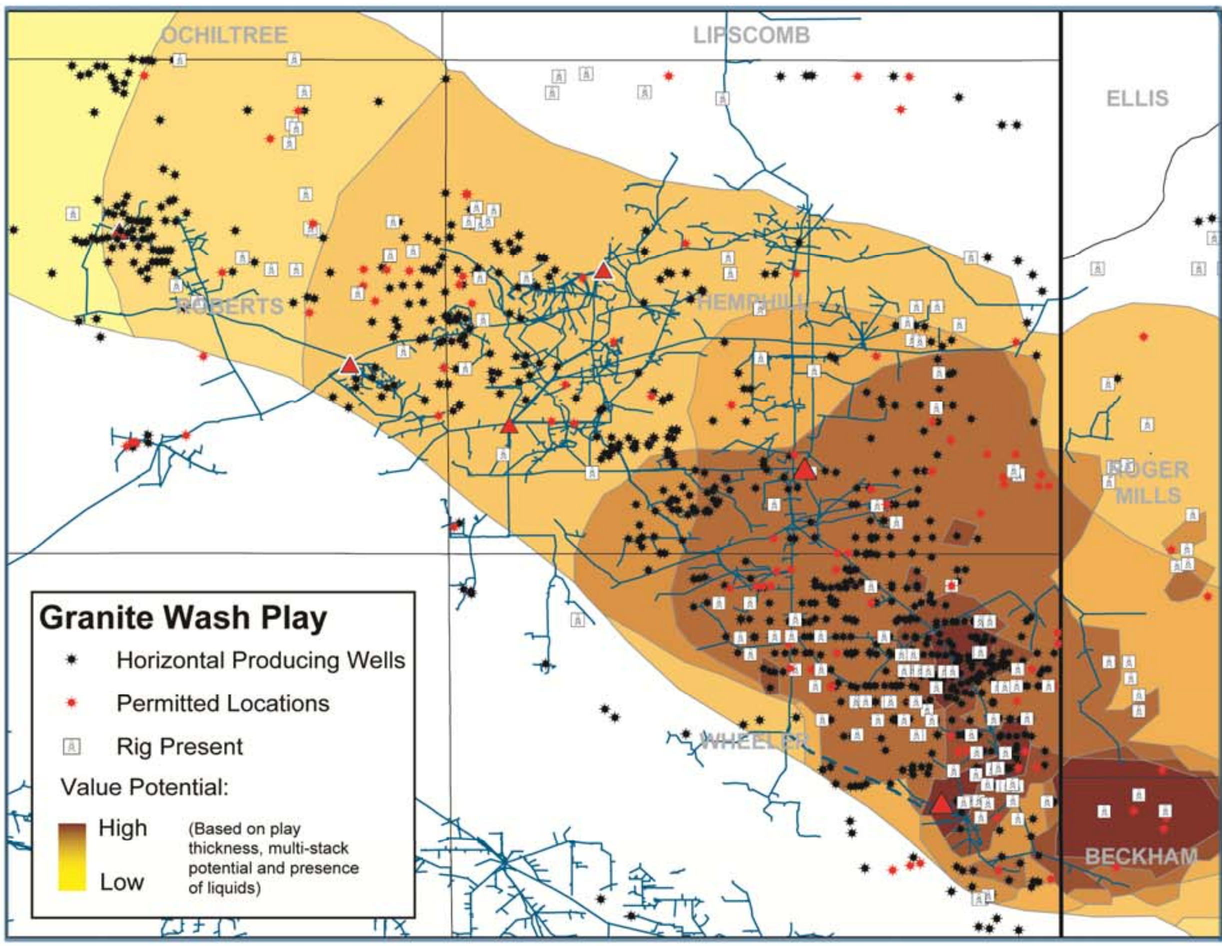
NYMEX Break-Even Economics (15% After-Tax IRR) (2)



(1) Based on Hart Energy and Rystad Energy research.
(2) Based on Credit Suisse estimates, using $90 per Bbl oil, excluding land costs.

The Granite Wash Fairway

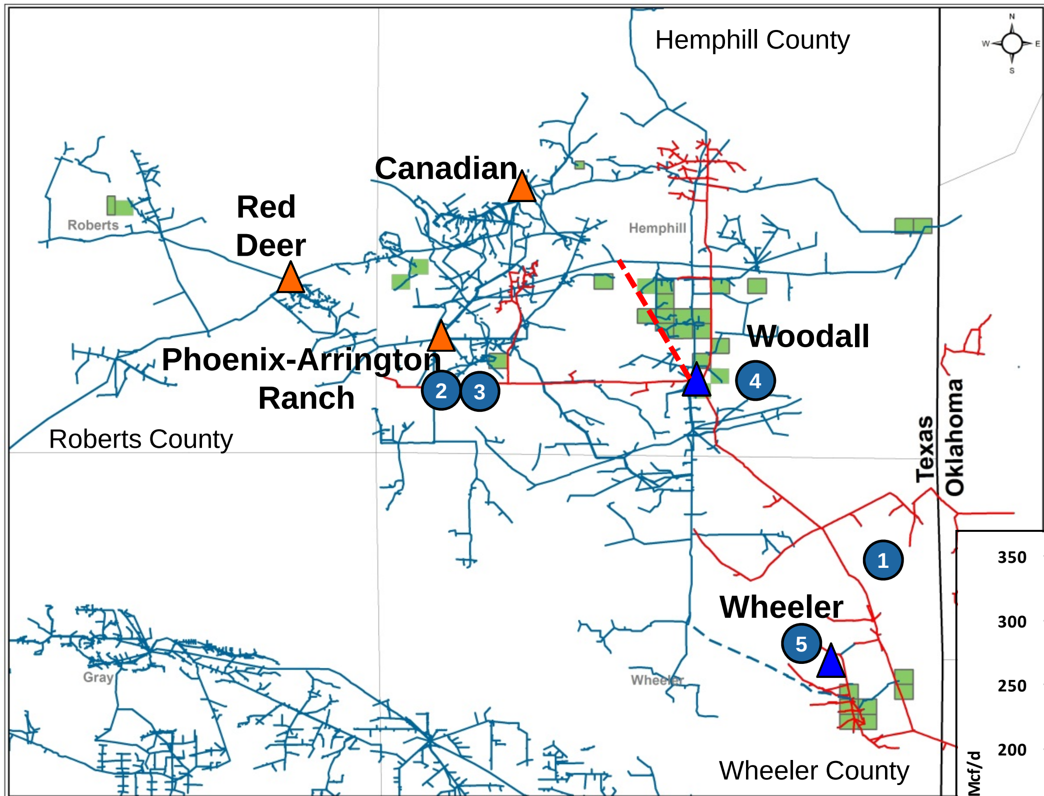
Eagle Rock is Well-Positioned to Serve Growing Production Volumes



- Tight sands formation with up to 3,000 feet of pay through multiple zones
- 132 directional / horizontal rigs running in Roberts, Hemphill and Wheeler counties
- World class well economics, particularly in core Northern Wheeler / Southern Hemphill counties
  - 30-day IPs of 10+ MMcfe/d
  - EURs of 6+ Bcfe

Source: Hart Energy and Rystad Energy research.

Building on Our Core; Delivering for Our Customers

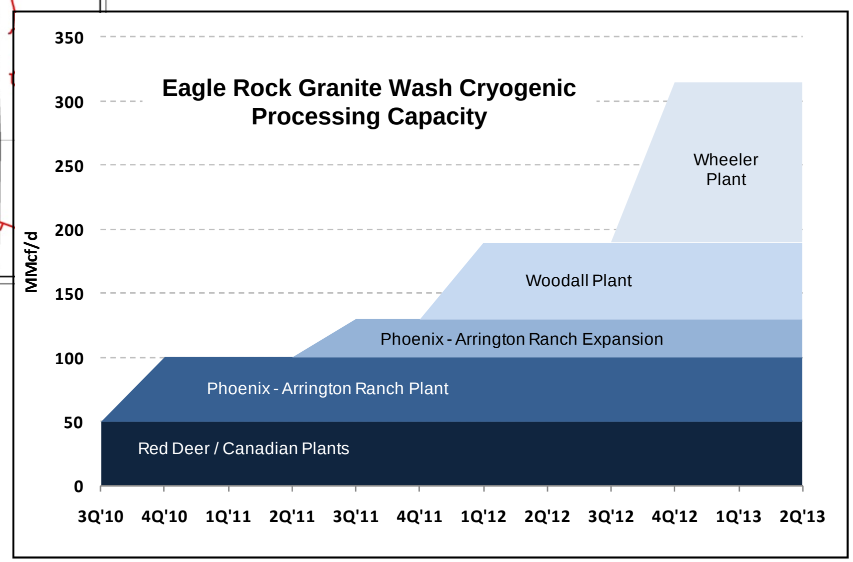


Eagle Rock Processing Facility
- Existing
- Planned
- CEFS Acquisition

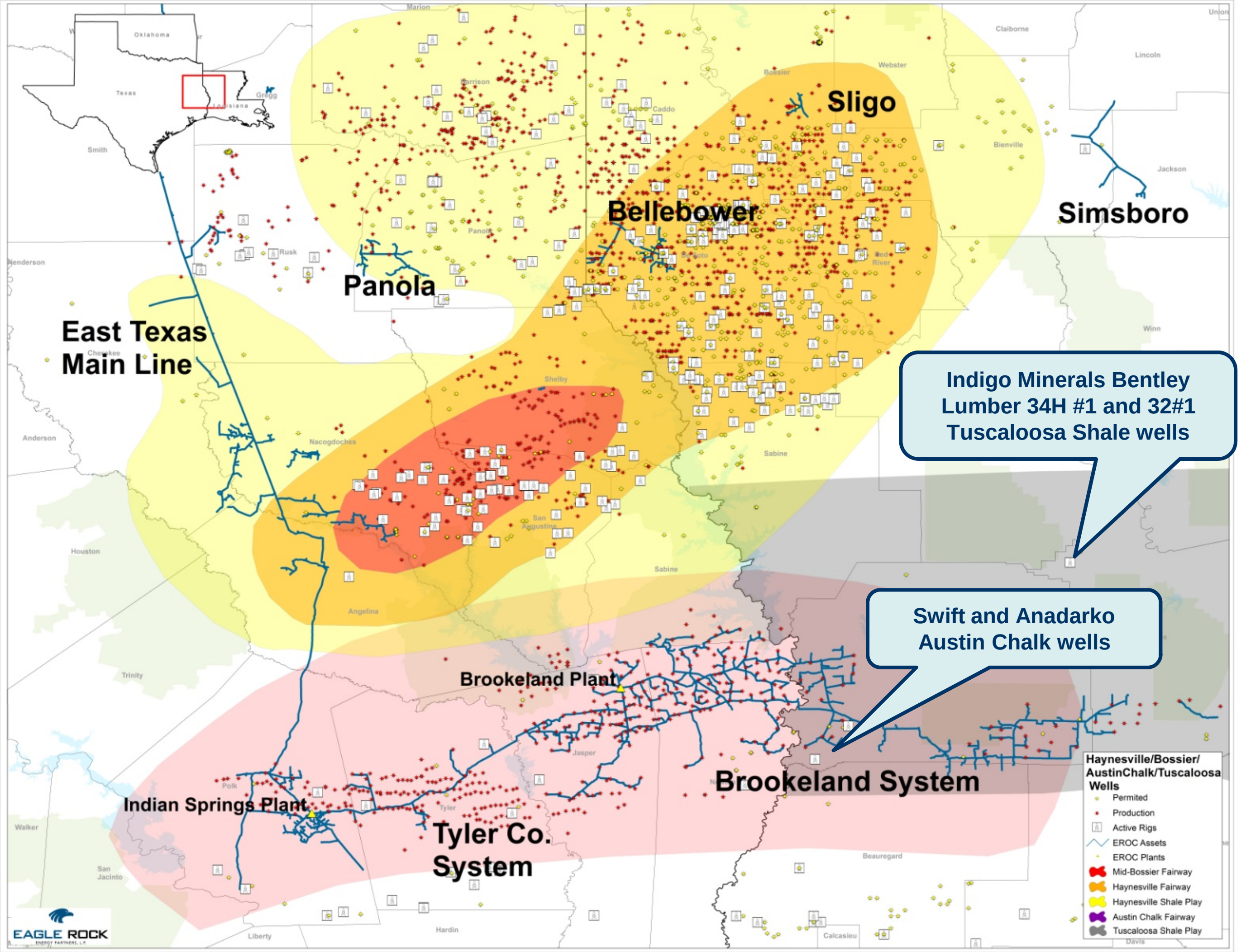
New producer customer acreage dedications
- Proposed new gathering line
- Proposed new 6-inch NGL line

Recent Activity

1	Oct. '10	Acquired Gathering Systems from CEFS
2	Dec. '10	Installed Phoenix-Arrington Ranch Plant (50 MMcf/d)
3	Oct. '11	Completed Phoenix-Arrington Ranch Plant Expansion (+30 MMcf/d)
4	1Q '12	Planned Installation of Woodall Plant (60 MMcf/d)
5	4Q '12	Planned Installation of Wheeler Plant (125 MMcf/d)



Strategic Footprint in East Texas



System Activity

Austin Chalk:

- Large independents staking 14 potential dedicated sites
- Drilling moving east into Louisiana with Austin Chalk and prospective Tuscaloosa Shale / Louisiana Eagle Ford Play
- Currently, four rigs running on dedicated acreage

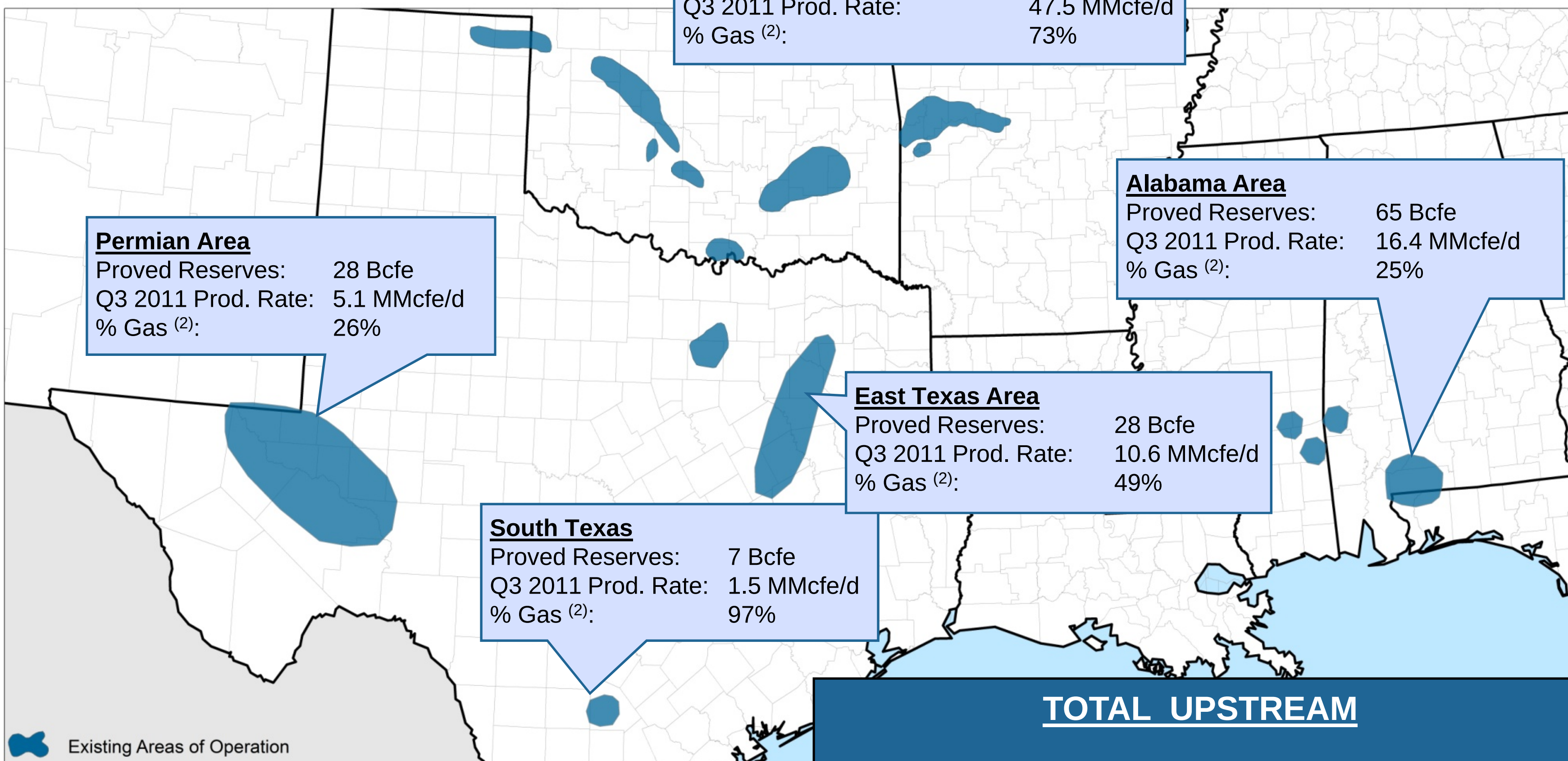
Source: SEC filings, industry investor presentations, HPDI and RigData.

Eagle Rock Energy Partners, L.P.

Upstream Business Overview

Wells Fargo Pipeline / MLP Symposium *December 2011*

Geographically Diverse Upstream Assets



Mid-Continent Assets [1]

Proved Reserves:	257 Bcfe
Q3 2011 Prod. Rate:	47.5 MMcfe/d
% Gas [2]:	73%

Permian Area

Proved Reserves:	28 Bcfe
Q3 2011 Prod. Rate:	5.1 MMcfe/d
% Gas [2]:	26%

Alabama Area

Proved Reserves:	65 Bcfe
Q3 2011 Prod. Rate:	16.4 MMcfe/d
% Gas [2]:	25%

East Texas Area

Proved Reserves:	28 Bcfe
Q3 2011 Prod. Rate:	10.6 MMcfe/d
% Gas [2]:	49%

South Texas

Proved Reserves:	7 Bcfe
Q3 2011 Prod. Rate:	1.5 MMcfe/d
% Gas [2]:	97%

TOTAL UPSTREAM

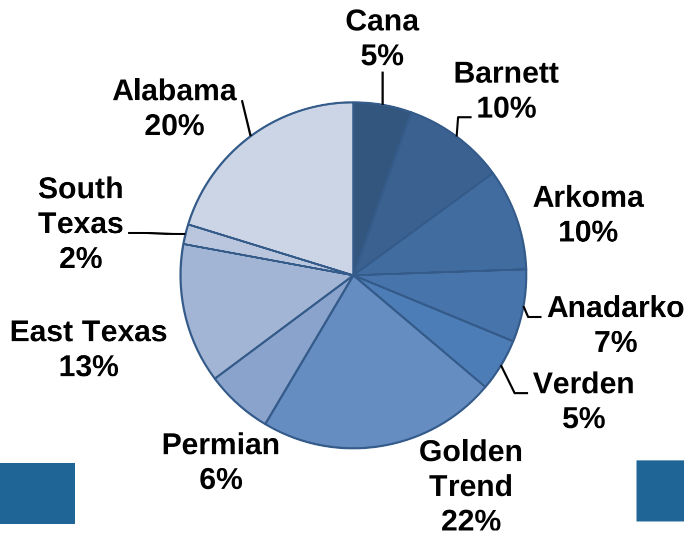
Proved Reserves:	**385 Bcfe**
Probable Reserves:	**400+ Bcfe**
Avg. Q3 2011 Production:	**81.1 MMcfe/d**
2011 Projected Exit Rate:	**86.0-88.0 MMcfe/d**

Note: Pro forma proved reserves as of 12/31/10 based on SEC pricing as of 12/31/10; probable reserves as of 12/31/10 based on 2/15/11 strip prices.
(1) Includes Barnett Shale.
(2) Based on production.

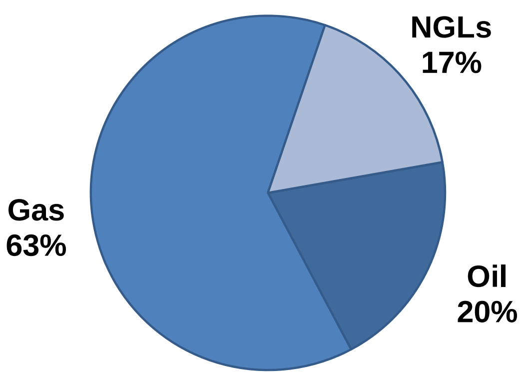
Diversified Reserve Base Across High Quality Basins

- Third quarter 2011 average production rate of 81.1 MMcfe/d
- Production growth anticipated from liquids-rich Cana Shale and Golden Trend plays in Oklahoma
  - 210 gross identified PUD drilling locations
  - 469 gross identified probable drilling locations across upstream portfolio

Production

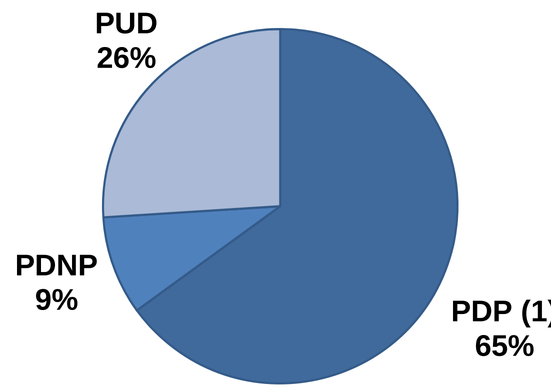


Reserves by Commodity



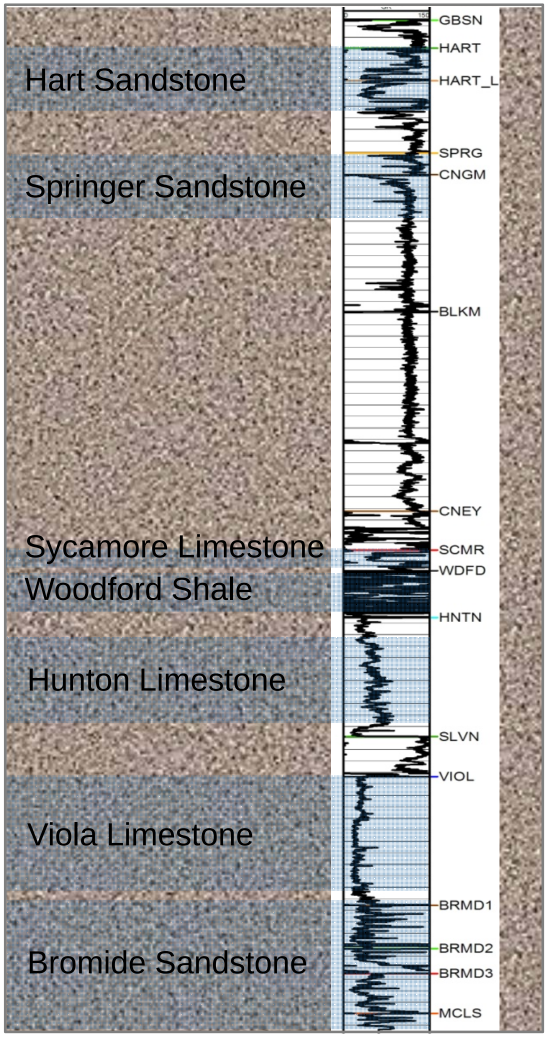
- Total pro forma proved reserves as of December 31, 2010 of 385 Bcfe
- 13.0 year reserve life index based on current production rates

Reserves by Category

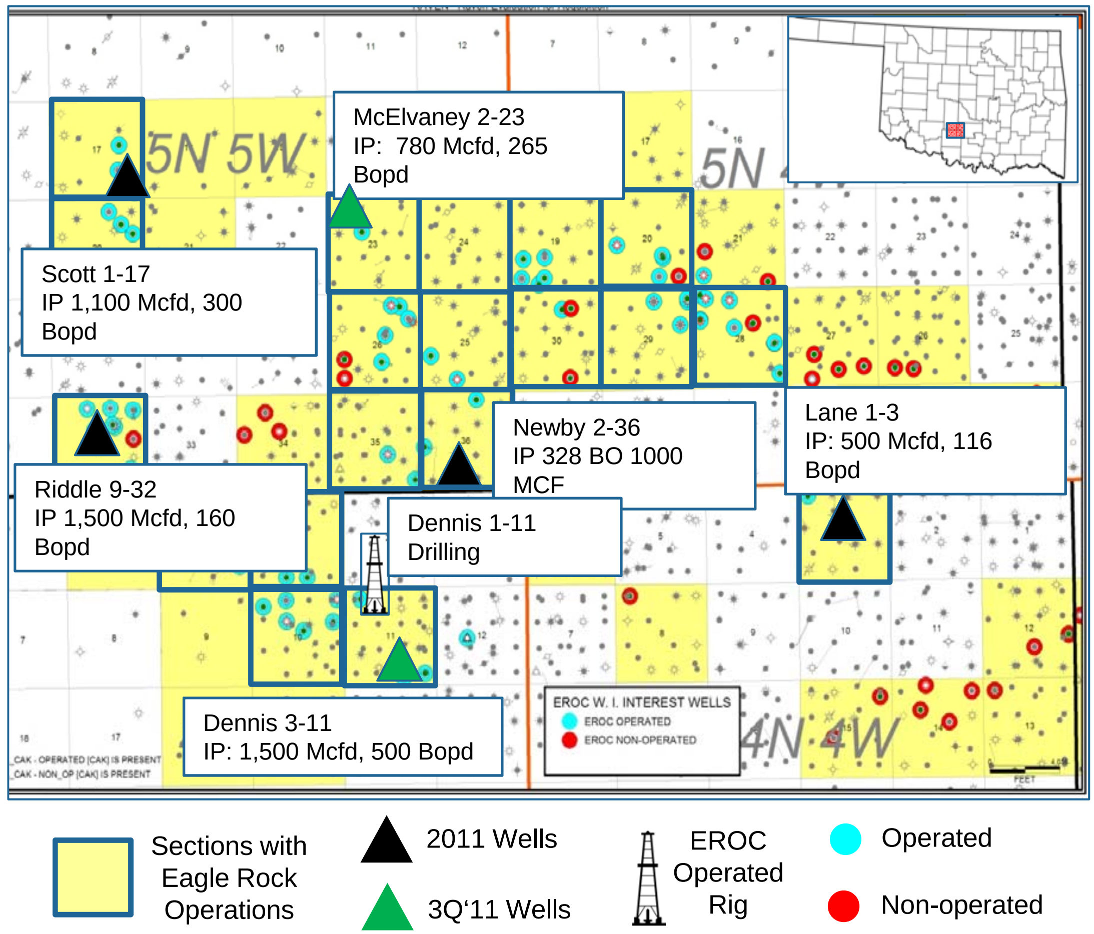


(1) Eagle Rock PDP reflects recategorization of reserves following the resumption of East Texas production associated with the Eustace facility.
Note: Pro forma reserves as of 12/31/10 based on SEC pricing as of 12/31/10.

Golden Trend Play

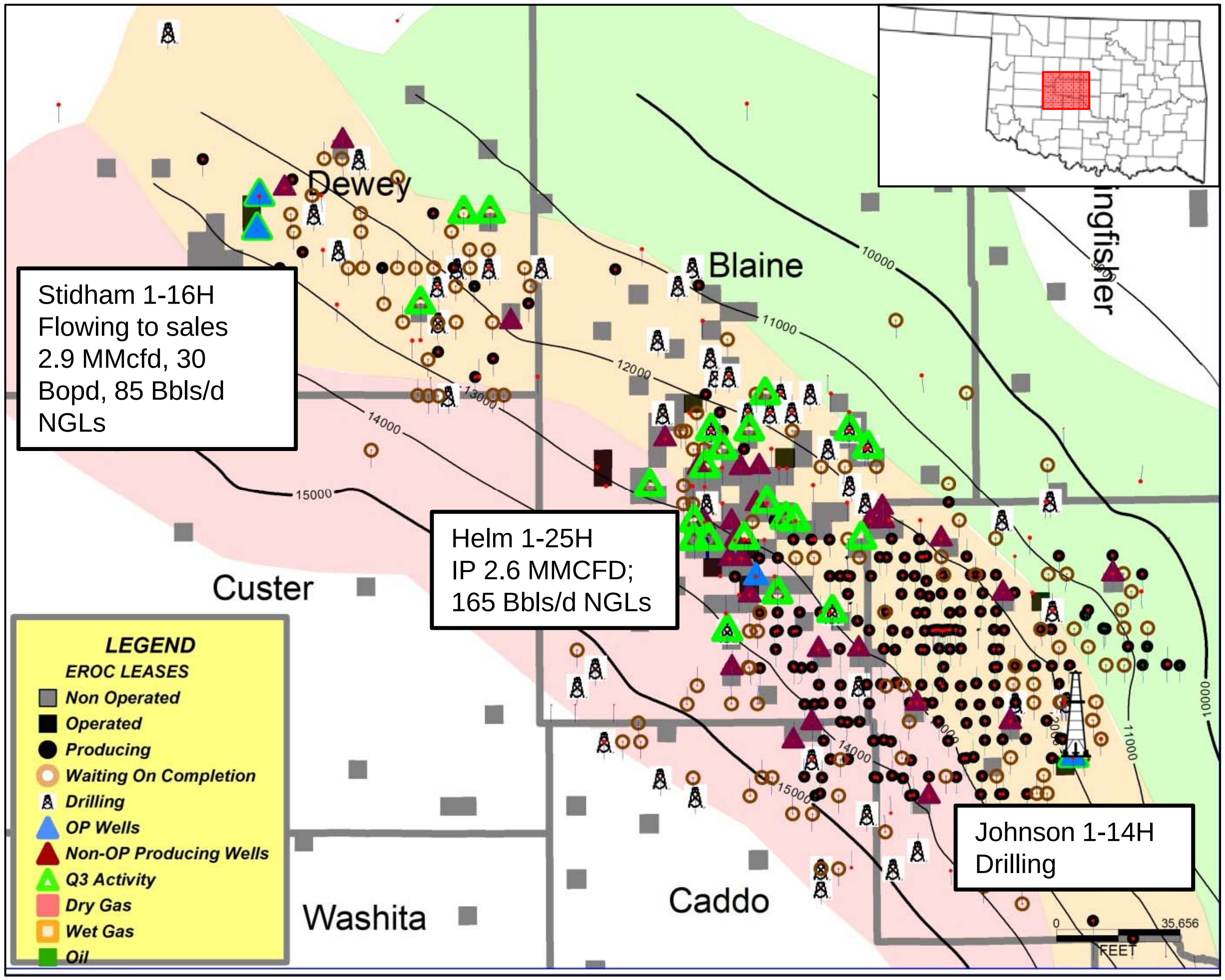


Liquids-rich field producing from multiple pay formations from 8,000' to 14,000' including Bromide, Big 4, Springer, Morrow, Hart, Deese

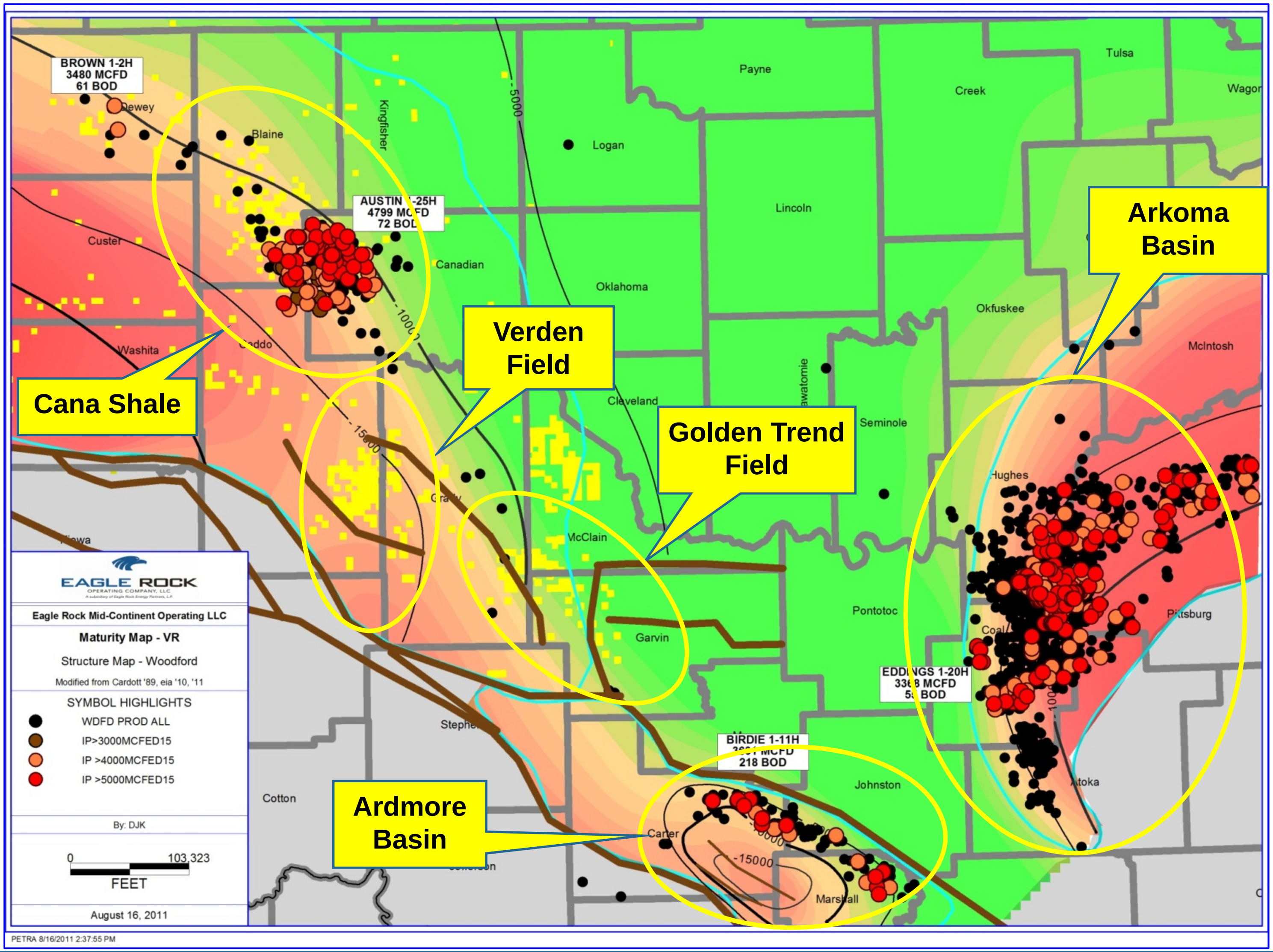


Cana Shale Play Drilling Activity

- 47 rigs currently drilling horizontal wells in the western Oklahoma Woodford "Cana" shale trend
  - Shale characterized by dry gas to the southwest and oil to the northeast
  - 296 Cana wells on production across play (35 with EROC WI)
  - 11 EROC Non-Op wells are WOC or first sales
- Majority of drilling activity conducted by large independent producers such as Devon, Cimarex, Continental, and Marathon
- EROC Cana Shale net leasehold totals 13,600 acres
  - Majority of acreage in wet gas "window"
  - One rig operated program
  - Participating with WI in 7-9 rigs drilling in play



Woodford Shale -- Potential Room to Run



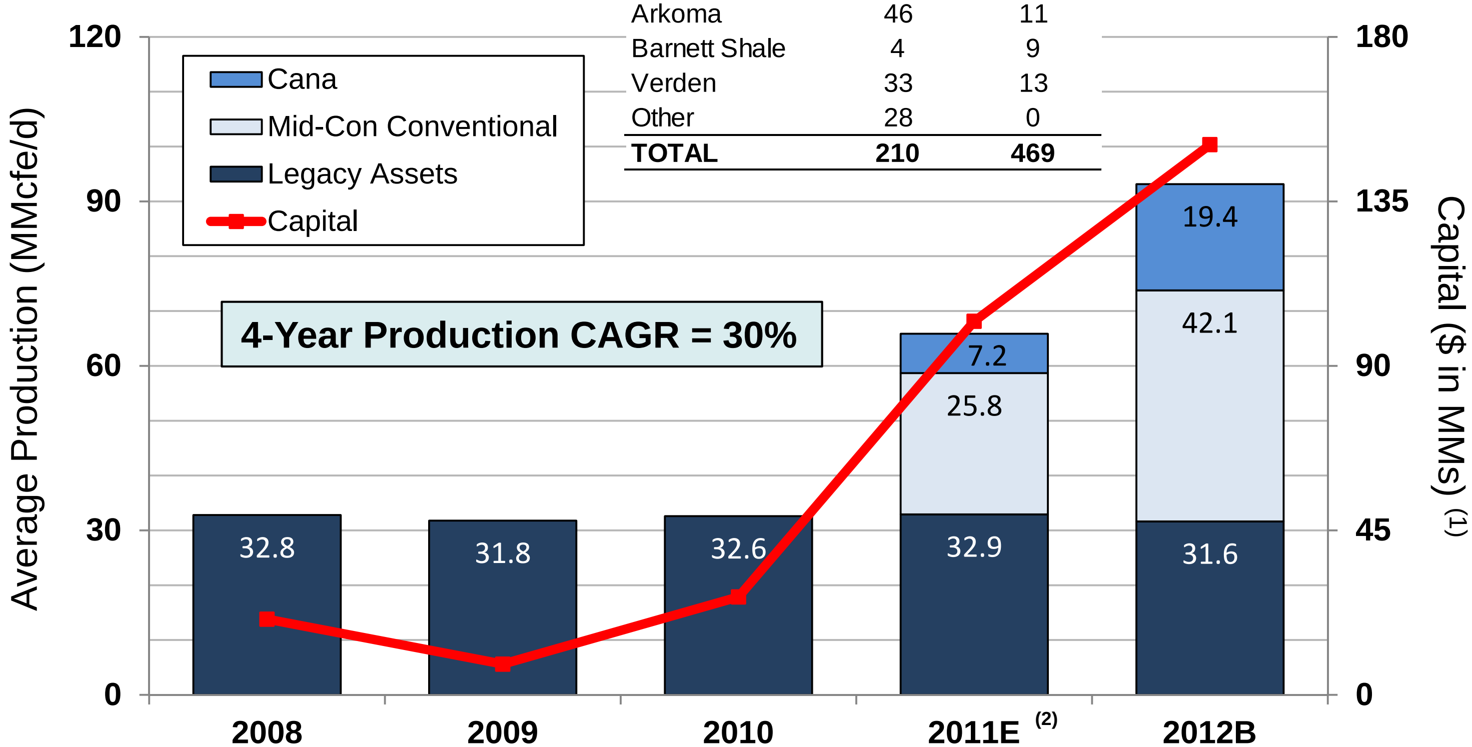
Eagle Rock acreage

Upstream Growth

Production Growth Driven Organically by Lower-Risk Drilling Inventory

Eagle Rock Identified Locations

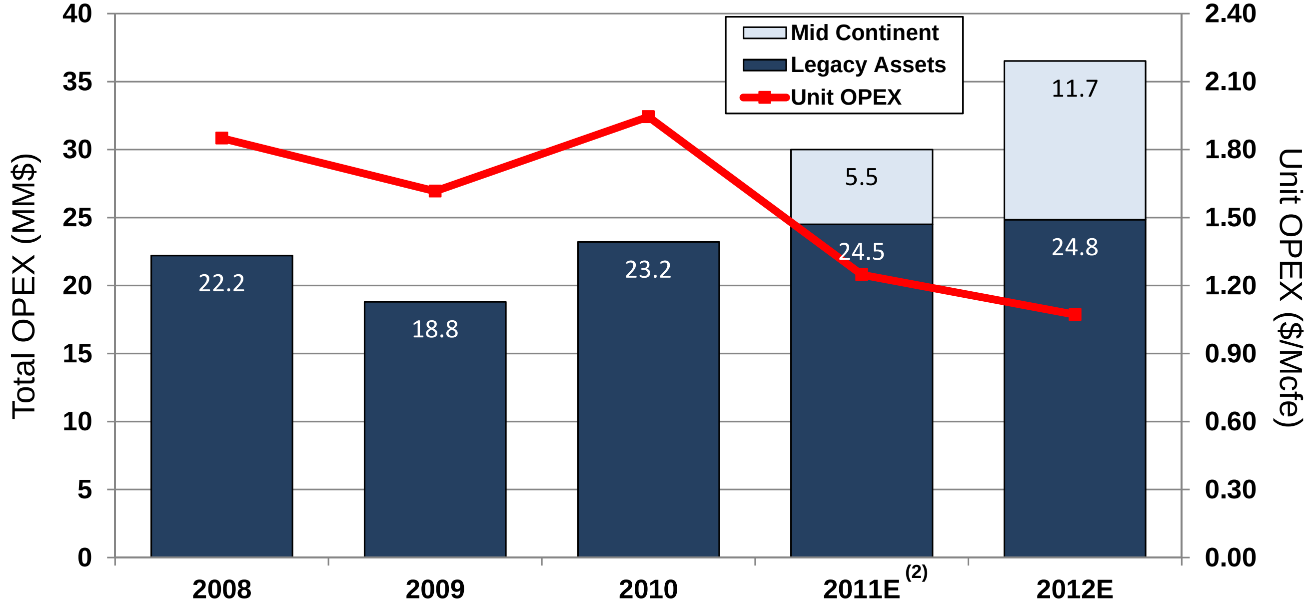
	PUD	PROB
Cana Shale	21	413
Golden Trend	36	2
Anadarko	42	21
Arkoma	46	11
Barnett Shale	4	9
Verden	33	13
Other	28	0
TOTAL	**210**	**469**



(1) This capital spending is subject to the availability of adequate sources, including cash from operations, borrowings under our revolving credit facility and potentially the issuance of additional equity or debt securities.
(2) Adjusted to reflect estimate of a full quarter of East Texas production (removing the impact of the Eustace processing facility shut-down).

Focus on Low Cost Operations

Upstream Historical and Projected Operating Costs (1)



- Operating expense of the legacy assets is driven by sulfur treating costs
  - 2010 OPEX averaged $1.95/Mcfe
  - Included $2.3 million of plant turnaround ($1.78/Mcfe removing turnaround and Eustace shut-down impact)
  - 2010 workover expense above normal levels
- In 2011 unit operating expense has benefitted from the addition of Mid-Continent assets and lower overall workover expense
  - Mid-Continent assets have a conventional gas composition resulting in lower treating expense
  - Large, existing gathering infrastructure reduces producer gathering and compression expense
  - Mid-Continent assets - $0.45/Mcfe

(1) OPEX excludes production, ad valorem taxes and post-production costs.
(2) Adjusted to reflect estimate of a full quarter of East Texas production (removing the impact of the Eustace processing facility shut-down).

Eagle Rock is Well-Positioned for Continued Growth

✓	Strong credit profile and capital availability
✓	Absence of incentive distribution rights enhances long-term accretion potential
✓	Core midstream operations in liquids-rich areas with substantial organic growth opportunities in Granite Wash and expansion potential in Austin Chalk and Louisiana
✓	Balanced midstream / upstream platform widens opportunity set
✓	Substantial drilling inventory (~680 drilling locations) focused in attractive basins including the Cana Shale and Golden Trend in Oklahoma
✓	Management's expectation to recommend $1.00/unit distribution by end of 2012 (1)

(1) Based on current expectations of business performance and future commodity prices. All actual distributions will be determined, declared and paid at the discretion of the Eagle Rock Board of Directors.

Eagle Rock Energy Partners, L.P.

Appendix

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Mid-Continent Acquisition

Transaction Overview

- Acquisition of all equity interests of CC Energy II L.L.C ("Crow Creek") for a total purchase price of $563.7 million
  – 60% of purchase price in form of equity to sellers, primarily Natural Gas Partners

Transaction Highlights

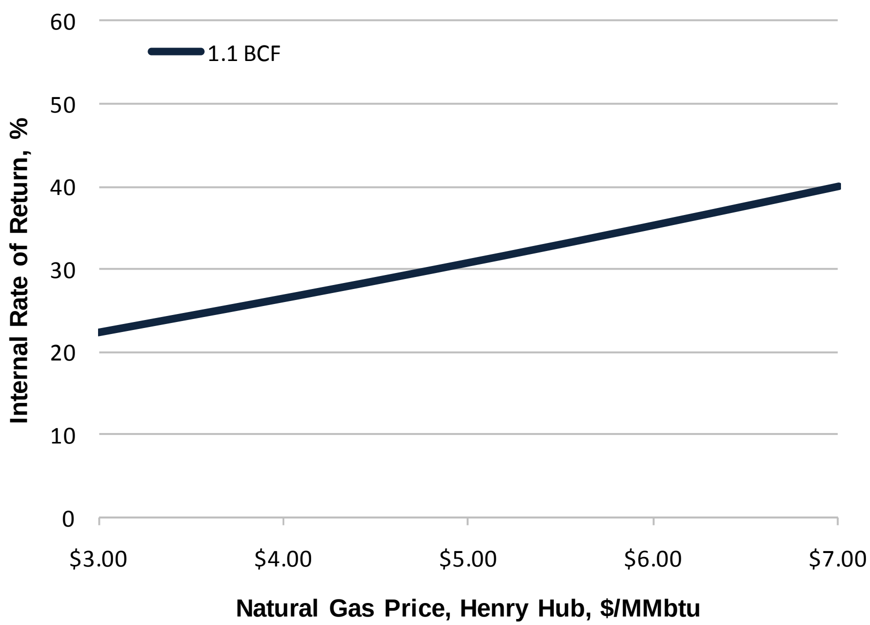
- Added significant scale and geographic diversity to existing Upstream Business
  – Proved reserves of 257 Bcfe (Total 3P reserves of 740.5 Bcfe) located in multiple basins across Oklahoma, Texas and Arkansas(1)
- Provides for long-term accretion (driven by production growth) to distributable cash flow per unit
- Expands portfolio of identified drilling opportunities (adds 182 PUD locations; 413 probable Cana locations; 56 probable non-Cana locations)
  – Lower-risk locations in established plays (76% operated)(2)
  – Base for organic production growth through 2015 (based on current drilling schedule)
- Lengthens total upstream reserve life (2010 YE Proved Reserves / 2010 Total Production) from 11 years to 17 years(3)
- Significant acreage position in Cana Shale provides upside to be realized through drilling

(1) Pro forma proved reserves as of 12/31/10 based on SEC pricing as of 12/31/10; total 3P reserves as of 12/31/10 based on 2/15/11 strip prices.
(2) Based on estimated 2011 production.
(3) Adjusted to reflect estimate of a full year of East Texas production (removing the impact of the Eustace processing facility shut-down).

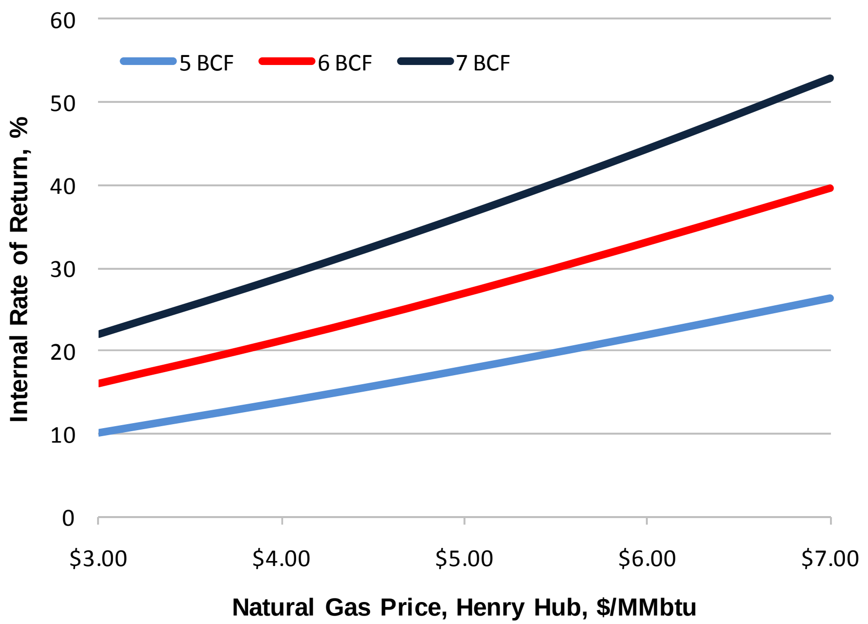
Robust Drilling Economics

- Exposure to liquids rich plays greatly enhances drilling economics in low gas price environment
- Early development of Cana Shale shows a range of EURs, with attractive drilling economics in liquids rich portion of the play using conservative reserve levels
- In the Golden Trend Field area, risk is minimized and reserve upside is greatly enhanced with multiple, prolific pay zones extending from 8,000 – 15,000 feet

Golden Trend Economics



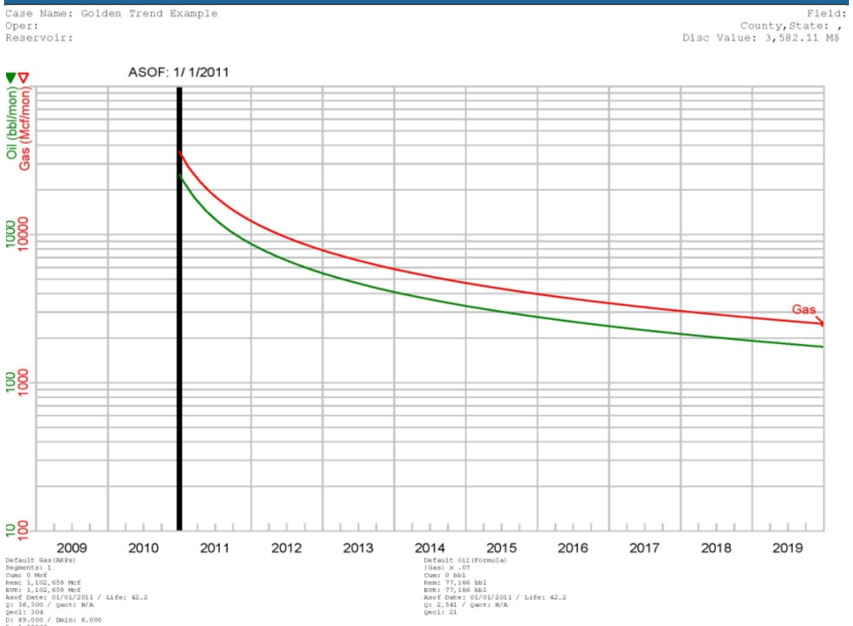
Cana Shale Economics



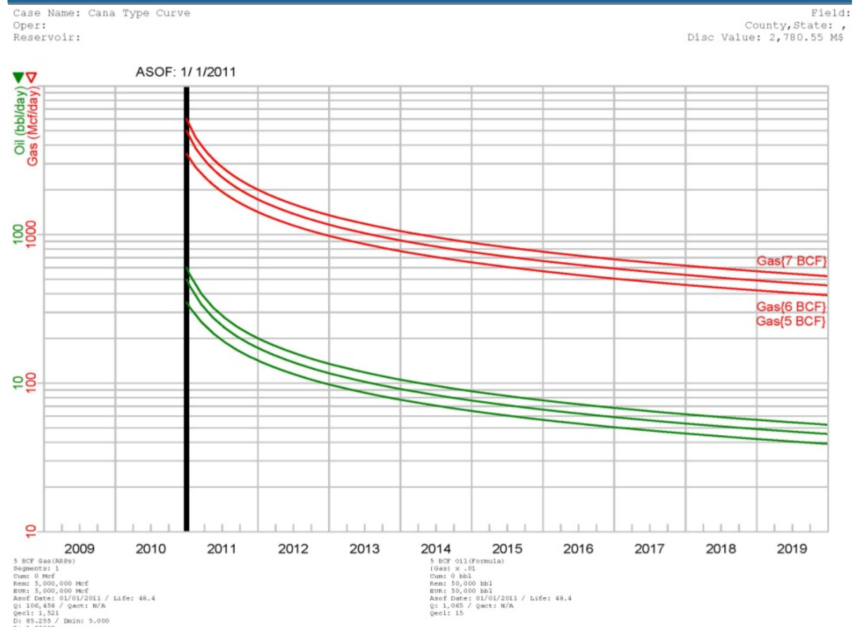
Note: Based on $85 per Bbl flat oil price deck and Eagle Rock management estimates.

Drilling Assumptions / Well Type Curves

Golden Trend Type Curve



Cana Shale Type Curve



Golden Trend Drilling Assumptions

- $3.0 million completed well cost
- EUR of 1.1 Bcfe
- 50 Bbl/MMcf Condensate; NGL yield of 80 Bbl/MMcf with 31% shrinkage
- 1,000 Btu residue gas
- Received natural gas price = Henry Hub less 0.6%
- Received oil price = WTI less $5.00/Bbl
- Received NGL price = WTI less 57%
- Opex: $2,500/well/month

Cana Shale Drilling Assumptions

- $8.6 million completed well cost
- EUR of 5-7 Bcfe
- 10 Bbl/MMcf Condensate; NGL yield of 50 Bbl/MMcf with 20% shrinkage
- 1,000 Btu residue gas
- Received natural gas price = Henry Hub less 10%
- Received oil price = WTI less $2.50/Bbl
- Received NGL price = WTI less 50%
- Opex: $3,500/well/month

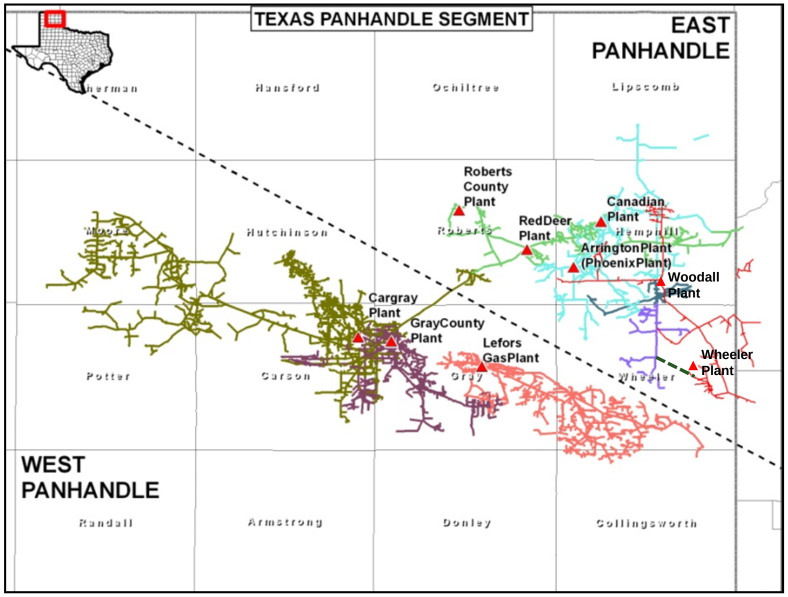
Note: These represent management's assumptions as to the performance of a typical well in these areas used in evaluating the Crow Creek Acquisition. They were based on the performance of certain wells (all of which were drilled by other oil and gas companies) in the areas, together with management's experience and estimates. In addition, the performance and costs of wells in these areas have shown substantial variance. There can be no guarantee that the actual costs or results of any well in these areas will match management's assumptions.

Midstream: Panhandle System

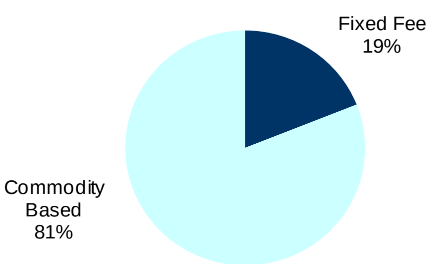
System Overview

• Miles of Pipeline:	3,963
• Processing Plants:	7
• Compression HP:	141,000
• LTM Avg. Gathering Volume:	151 MMcf/d
• LTM Avg. Equity NGL / Condensate Volume:	5.0 Mbbl/d
• LTM Operating Income (2):	$86.1 million
• LTM Capex (2):	$41.0 million
• Producing Formations:	Granite Wash Morrow Brown Dolomite Cleveland

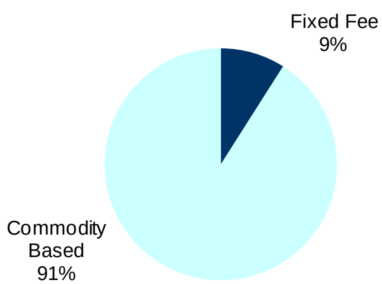
Map of Texas Panhandle System (1)



Contract Mix by Throughput (3)



Gross Margin (3)



East Processing Plants	West Processing Plants
Phoenix	Cargray
Canadian	Gray County
Red Deer	Lefors
Roberts Co.	
Woodall (Under Construction)	
Wheeler (Announced)	

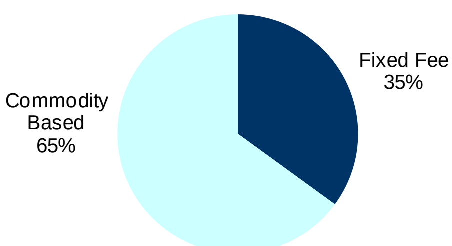
(1) Includes planned installation and construction of Woodall Plant in Hemphill County.
(2) LTM as of 9/30/2011. Excludes Depreciation, depletion, amortization and impairment.
(3) Based on December 2010.

Midstream: East Texas System

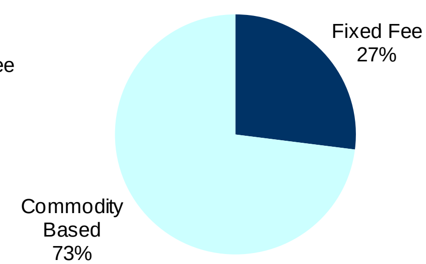
System Overview

- Miles of Pipeline: 1,213
- Processing Plants: 7
- Compression HP: 49,700
- LTM Avg. Gathering Volume: 190 MMcf/d
- LTM Avg. Equity NGL / Condensate Volume: 1.1 Mbbl/d
- LTM Operating Income (1): $35.1 million
- LTM Capex (1): $15.4 million
- Producing Formations: Austin Chalk, James Lime Trend, Travis Peak, Haynesville Shale, Cotton Valley, Woodbine

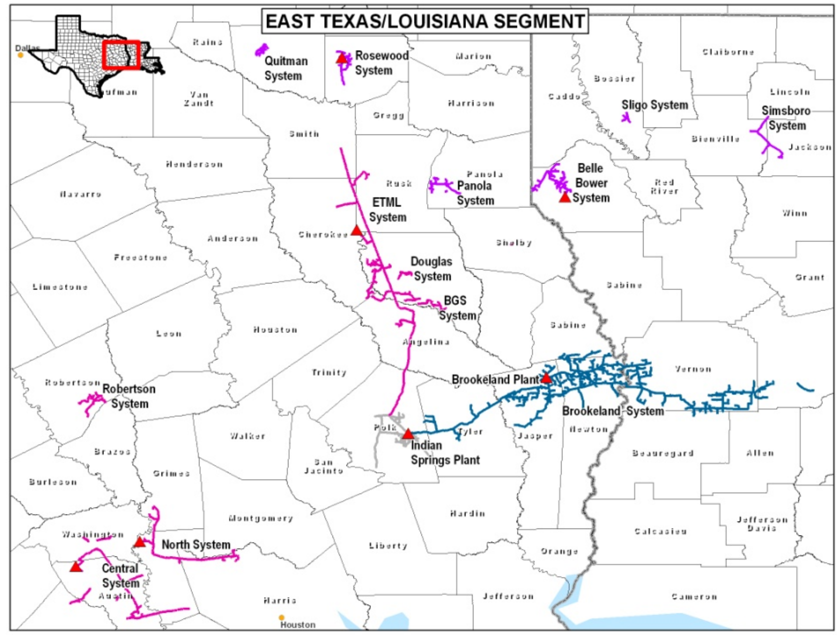
Contract Mix by Throughput (2)



Gross Margin (2)



Map of East Texas System



Processing Plants

Brookeland

Indian Springs

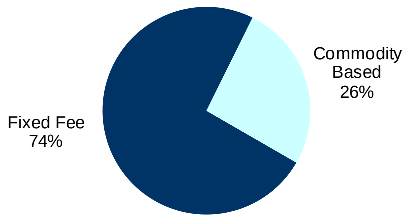
(1) LTM as of 9/30/2011. Excludes Depreciation, depletion and amortization.
(2) Based on December 2010.

Midstream: South Texas System

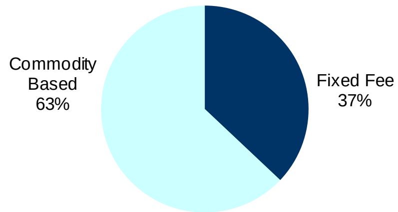
System Overview

- Miles of Pipeline: 266
- Processing JT Skids: 3
- Compression HP: 15,300
- LTM Operating Income (1): $5.1 million
- LTM Capex (1): $0.1 million

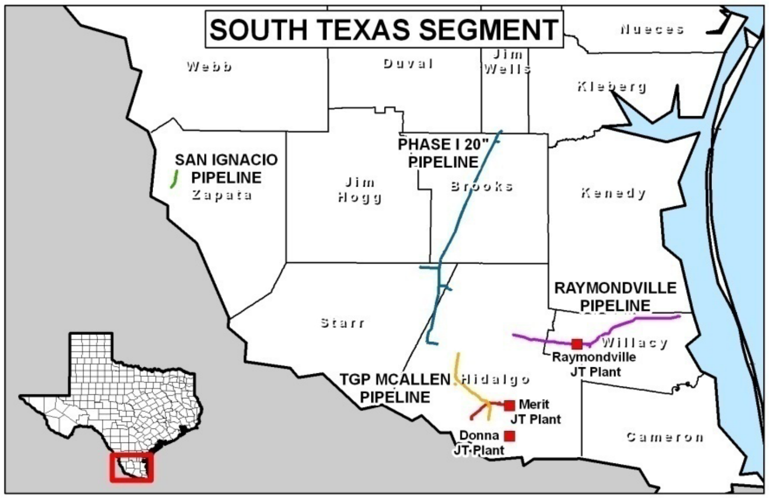
Contract Mix by Throughput (2)



Gross Margin (2)



Map of South Texas System



Producer Activity / Competitive Positioning

- Major producers are Chesapeake and Sanchez Oil & Gas in South Texas
- Activity has slowed due to lower natural gas commodity prices
- Phase 1 20-inch provides lower pressure service with access to two competing processing plants for producers

Processing JT Skids

Raymondville

Donna

Merit

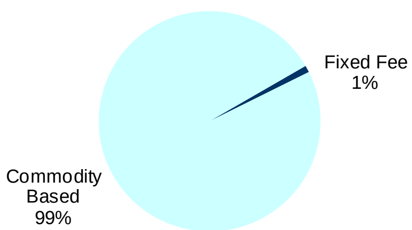
(1) LTM as of 9/30/2011. Excludes Depreciation, depletion, amortization and discontinued operations.
(2) Based on December 2010.

Midstream: Gulf of Mexico System

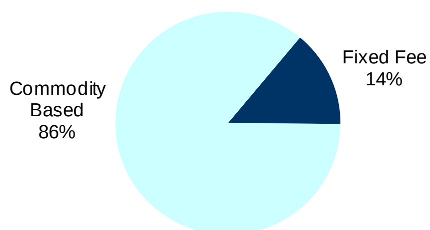
System Overview

• Miles of Pipeline:	40
• Processing Plants:	2 (non-operated)
• Compression HP:	14,180
• LTM Operating Income (1):	$3.3 million
• LTM Capex (1):	$0.2 million

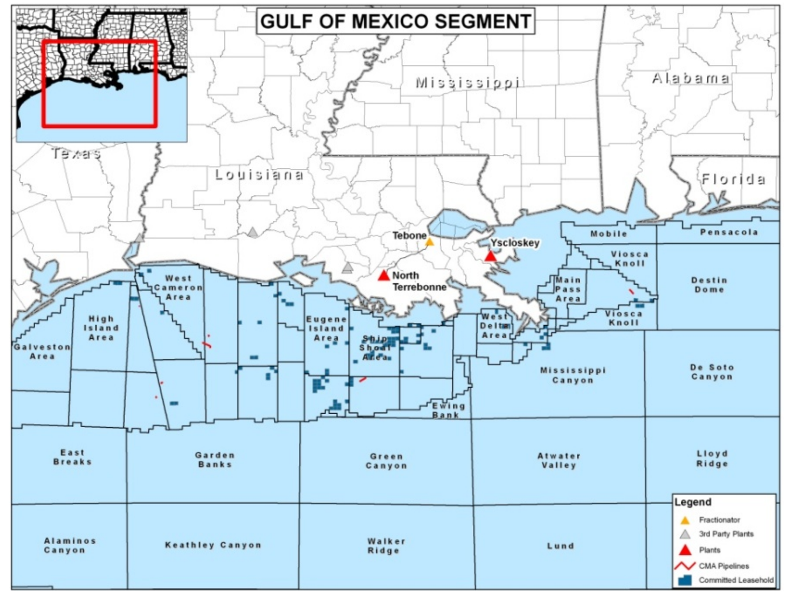
Contract Mix by Throughput (2)



Gross Margin (2)



Gulf of Mexico System



Producer Activity / Competitive Positioning

- Producer interests in approximately 115 blocks committed to life-of-lease contracts
  - Davy Jones discovery in shallow water covers some of Eagle Rock's committed leases
  - Deep subsalt shelf drilling could provide additional upside
- Major producers are Stone Energy and McMoran Exploration
- Contracts are life-of-lease commitments and typically percent of proceeds with fixed floors
- Have processing contracts with four third party plants and our two equity plants
  - Provides ability to handle producers' needs across the Gulf of Mexico

Processing Plants	Operating Interest
North Terrebone	2.63%
Yscloskey	10.54%

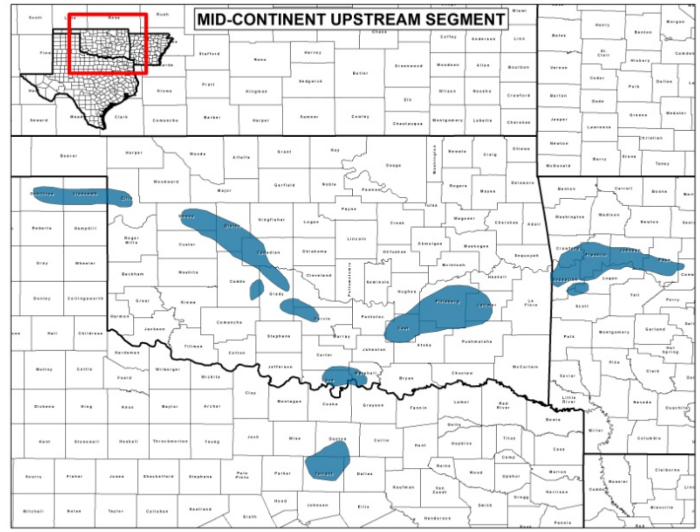
(1) LTM as of 9/30/2011. Excludes Depreciation, depletion and amortization.
(2) Based on December 2010.

Mid-Continent: Upstream Asset

Asset Overview

- Acquisition Date: May 3, 2011
- Oklahoma Counties: Dewey, Blaine, Canadian, Caddo, Grady, Love, Marshall Coal, Pittsburg, Latimer
- Texas Counties: Tarrant, Ochiltree, Lipscomb
- Arkansas Counties: Franklin, Johnson, Pope, Sebastian, Scott Logan, Crawford
- Operated Producing Wells: 330
- Non-Op Wells: 1,063
- Net Acreage: 115,500
- Net Reserves: 123.4 MMboe (740.5 Bcfe)
- Average Operated W.I.: 84%
- Producing Formations: Woodford, Springer, Cleveland, Bromides
- Gas Stream Composition: Various

Mid-Continent Properties



2011 Objectives

- Fully integrate the Crow Creek acquisition into the Eagle Rock Upstream business
- Grow production on the Cana Shale leasehold and within the Golden Trend field with both operated and non-operated drilling and recompletion programs
- Continue to acquire leasehold in the productive liquids-rich window of the Cana Shale play and in the Golden Trend field area

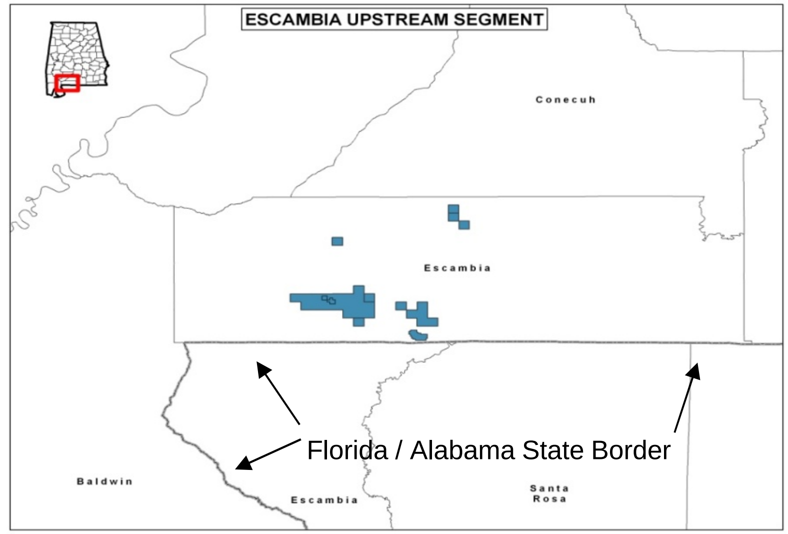
Alabama: Upstream Asset

Asset Overview

• Acquisition Date:	July 31, 2007
• Alabama Counties:	Escambia, Choctaw
• Operated Producing Wells:	29
• Non-Op Wells:	2
• Net Acreage:	13,000
• Net Reserves:	10.9 MMboe (65.4Bcfe)
• Average Operated W.I.:	73%
• Producing Formations:	Smackover, Norphlet
• Gas Stream Composition (+/-):	20% H_2S 45% CO_2

- Assets include two treating plants (100 MMcf/d capacity) and one cryogenic processing plant (50 MMcf/d) to remove H_2S and CO_2 prior to sales

Alabama Properties



2010 Operating Statistics

Net Production:

• Gas Mcf/d:	3,578
• Oil Bo/d:	1,566
• NGLs Bl/d:	647
• Sulfur LT/d:	169
• Total Mcfe/d:	16,798 (21% gas)

Financial Summary

• Revenue ($ in millions):	$55.4
• Operating Expense ($ in millions) [(1)]:	$14.3
• Unit Operating Expense ($/BOE) [(1)]:	$14.28

2011 Objectives

- Exploit behind-pipe zones in current wellbores
- Continue to increase market flexibility for all products
- Optimize gathering system to increase production
- Reconfigure wells and install artificial lift to improve flow efficiencies
- Improve SO_2 recoveries at BEC and Flomaton facilities to comply with changing emissions requirements

(1) Excluding taxes.

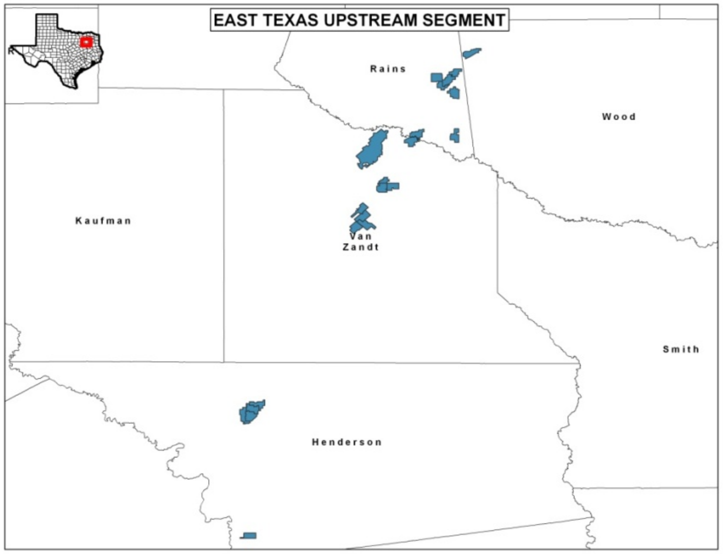
East Texas Smackover Trend Assets

Asset Overview

• Acquisition Date:	July 31, 2007
• Texas Counties:	Wood, Rains, Van Zandt, Henderson
• Operating Producing Wells:	34
• Non-Op Producing Wells:	123 (ETX/LA)
• Net Acreage:	16,000
• Net Reserves:	4.5 MMboe (27.0 Bcfe)
• Average Operated W.I.:	83%
• Producing Formations:	Smackover, Cotton Valley
• Gas Composition:	20-40% H_2S

- Eagle Rock's East Texas production is treated and processed by Tristream Energy facilities

East Texas Properties



2010 Operating Statistics (1)

Net Production:

• Gas Mcf/d:	5,199
• Oil Bo/d:	261
• NGLs Bl/d:	518
• Sulfur LT/d:	103
• Total Mcfe/d:	9,876 (53% gas)

Financial Summary

• Revenue ($ in millions):	$19.0
• Operating Expense ($ in millions) (2):	$3.9
• Unit Operating Expense ($/BOE) (2):	$8.54

2011 Objectives

- Exploit new Cotton Valley discovery with targeted drilling and well re-entries
- Improve well performance through well re-configuration and artificial lift
- Optimize compression to reduce wellhead pressures and increase production

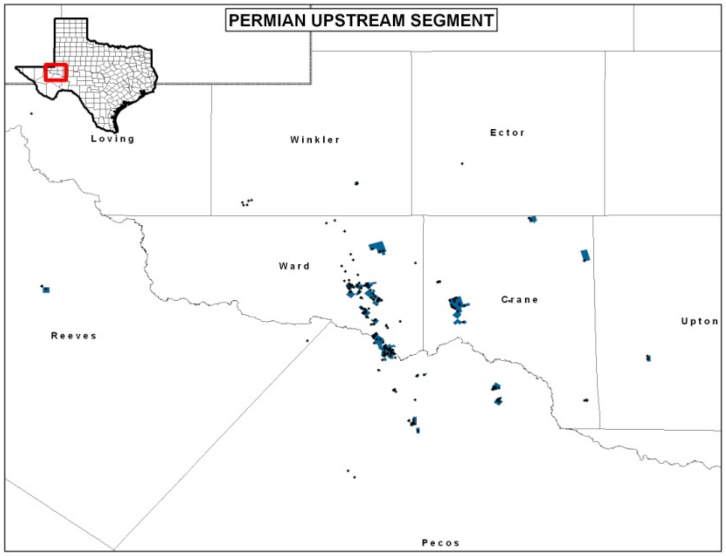
(1) Includes the Partnership's Mississippi and South Texas operations.
(2) Excluding taxes.

Permian Basin Assets

Asset Overview

• Acquisition Date:	April 30, 2008
• Texas Counties:	Ward, Crane, Pecos
• Operated Producing Wells:	186
• Non-Op Producing Wells:	21
• Net Acreage:	24,000
• Net Reserves:	4.7 MMboe (28.2 Bcfe)
• Average Operated W.I.:	96%
• Producing Formations:	Yates, Queen, San Andres, Wichita Albany, Holt, Wolfcamp and Penn

Permian Basin Properties



2010 Operating Statistics

Net Production:

• Gas Mcf/d:	1,563
• Oil Bo/d:	469
• NGLs Bl/d:	221
• Total Mcfe/d:	5,706 (27% gas)

Financial Summary

• Revenue ($ in millions):	$17.4
• Operating Expense ($ in millions) (1):	$5.0
• Unit Operating Expense ($/BOE) (1):	$14.53

2011 Objectives

- Exploit behind-pipe reserves in multiple horizons with low risk workovers
- Evaluate tertiary CO_2 flood potential
- Target bolt-on acquisition opportunities

(1) Excluding taxes.

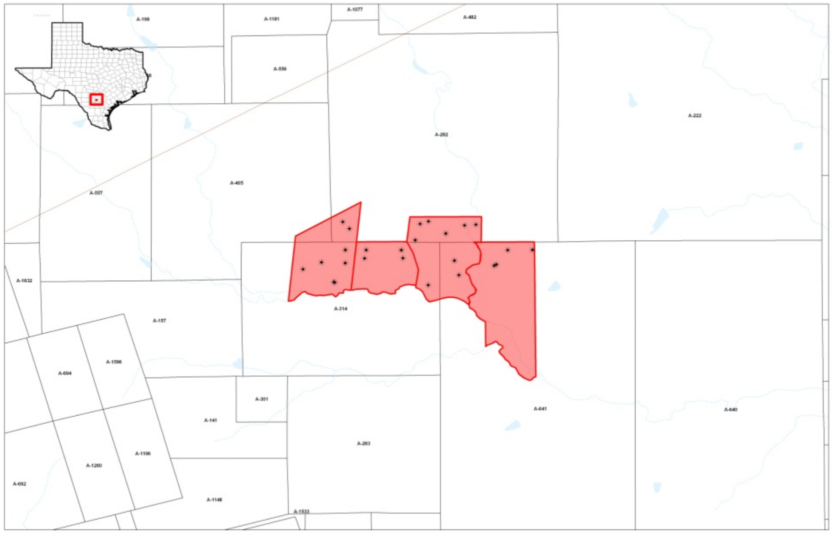
South Texas Upstream Assets

Asset Overview

• Acquisition Date:	July 31, 2007
• Texas Counties:	Atascosa
• Operating Producing Wells:	11
• Net Acreage:	1,400
• Net Reserves:	1.1 MMboe (6.6 Bcfe)
• Average Operated W.I.:	100%
• Producing Formations:	Edwards

- Successful re-completion program conducted in 2008 with infill drilling locations identified for future development

South Texas Properties



- Acreage is well-positioned in the “wet” gas window of the Eagleford Shale
  - – Evaluating options to exploit resource

Note: South Texas operations included in East Texas operating statistics.

SEC Reserve Disclosures

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only “reserves” as defined by SEC rules. Estimates of reserves in this communication are based on economic assumptions with regard to commodity prices (NYMEX strip) that differ from the prices required by the SEC (historical 12 month average) to be used in calculating reserves estimates of reserves prepared in accordance with SEC definitions and guidelines. In addition, the SEC generally prohibits in SEC filings the reporting of reserves of different categories on a combined basis (3P) because each category of proved, probable and possible reserves involves substantially different risks of ultimate recovery. Factors affecting ultimate recovery include the scope of our proposed drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors, and actual drilling results, including geological and mechanical factors affecting recovery rates. Accordingly, actual quantities that may be ultimately recovered from the Partnership's interests may differ substantially from the Partnership’s estimates of reserves. In addition, the Partnership's estimates of reserves may change significantly as development of the Partnership’s properties provide additional data.

Use of Non-GAAP Financial Measures

This presentation includes, and certain statements made during this presentation may include, the non-generally accepted accounting principles, or non-GAAP, financial measures of Adjusted EBITDA. The accompanying non-GAAP financial measures schedule provides reconciliations of Adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States, or GAAP, with respect to the references to Adjusted EBITDA that are of a historical nature. Where references are forward-looking or prospective in nature, and not based in historical fact, this presentation does not provide a reconciliation. Eagle Rock could not provide such reconciliation without undue hardship because the Adjusted EBITDA numbers included in the presentation, and that may be included in certain statements made during the presentation, are estimations, approximations and/or ranges. In addition, it would be difficult for Eagle Rock to present a detailed reconciliation on account of many unknown variables for the reconciling items. For an example of the reconciliation, please consult the reconciliations included for the historical Adjusted EBITDA numbers in this appendix. Non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income (loss), operating income (loss), cash flows from operating activities or any other GAAP measure of liquidity or financial performance.

Eagle Rock defines Adjusted EBITDA as net income (loss) plus or (minus) income tax provision (benefit); interest-net, including realized interest rate risk management instruments and other expense; depreciation, depletion and amortization expense, impairment expense; other operating expense, non-recurring; other non-cash operating and general and administrative expenses, including non-cash compensation related to our equity-based compensation program; unrealized (gains) losses on commodity and interest rate risk management related instruments; (gains) losses on discontinued operations and other (income) expenses.

Eagle Rock uses Adjusted EBITDA as a measure of its core profitability to assess the financial performance of its assets. Adjusted EBITDA also is used as a supplemental financial measure by external users of Eagle Rock's financial statements such as investors, commercial banks and research analysts. For example, Eagle Rock's lenders under its revolving credit facility use a variant of Eagle Rock's Adjusted EBITDA in a compliance covenant designed to measure the viability of Eagle Rock and its ability to perform under the terms of its revolving credit facility; Eagle Rock, therefore, uses Adjusted EBITDA to measure its compliance with its revolving credit facility. Eagle Rock believes that investors benefit from having access to the same financial measures that its management uses in evaluating performance. Adjusted EBITDA is useful in determining Eagle Rock's ability to sustain or increase distributions. By excluding unrealized derivative gains (losses), a non-cash, mark-to-market benefit (charge) which represents the change in fair market value of Eagle Rock's executed derivative instruments and is independent of its assets' performance or cash flow generating ability, Eagle Rock believes Adjusted EBITDA reflects more accurately Eagle Rock's ability to generate cash sufficient to pay interest costs, support its level of indebtedness, make cash distributions to its unitholders and general partner and finance its maintenance capital expenditures. Eagle Rock further believes that Adjusted EBITDA also describes more accurately the underlying performance of its operating assets by isolating the performance of its operating assets from the impact of an unrealized, non-cash measure designed to describe the fluctuating inherent value of a financial asset. Similarly, by excluding the impact of non-recurring discontinued operations, Adjusted EBITDA provides users of the Partnership's financial statements a more accurate picture of its current assets' cash generation ability, independently from that of assets which are no longer a part of its operations.

Use of Non-GAAP Financial Measures (Continued)

Eagle Rock's Adjusted EBITDA definition may not be comparable to Adjusted EBITDA or similarly titled measures of other entities, as other entities may not calculate Adjusted EBITDA in the same manner as Eagle Rock. For example, Eagle Rock includes in Adjusted EBITDA the actual settlement revenue created from its commodity hedges by virtue of transactions undertaken by it to reset commodity hedges to prices higher than the then-current forward strip price for such future period or purchase puts or other similar floors despite the fact that Eagle Rock excludes from Adjusted EBITDA any charge for amortization of the cost of such commodity hedge reset transactions or puts. Eagle Rock has reconciled historical Adjusted EBITDA numbers to the GAAP financial measure of net income (loss) in the appendix to this presentation but has not reconciled prospective Adjusted EBITDA numbers.

Adjusted EBITDA Reconciliation

Adjusted EBITDA Reconciliation

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ in thousands)		*($ in thousands)*	
Net cash flows provided by operating activities	$59,258	$34,145	$84,951	$76,807
Add (deduct):				
Discontinued operations	(197)	166	210	43,811
Depreciation, depletion, amortization and impairment	(44,910)	(29,324)	(105,068)	(87,367)
Amortization of debt issuance costs	(642)	(242)	(1,688)	(1,062)
Risk management portfolio value changes	94,634	(14,225)	114,403	31,482
Reclassing financing derivative settlements	1,263	373	3,706	1,001
Other	(1,106)	(1,498)	22	(5,705)
Accounts receivables and other current assets	(4,283)	(13,398)	1,200	(22,109)
Accounts payable, due to affiliates and accrued liabilities	(6,929)	(1,008)	91	9,474
Other assets and liabilities	277	(226)	892	555
Net income (loss)	$97,365	($25,237)	$98,719	$46,887
Add (deduct):				
Interest (income) expense, net	13,766	8,470	33,120	26,935
Depreciation, depletion and amortization	44,910	29,324	105,068	87,367
Income tax (benefit) provision	(1,077)	(1,244)	(1,810)	(970)
EBITDA	$154,964	$11,313	$235,097	$160,219
Add (deduct):				
Risk management portfolio value changes	(93,846)	20,156	(88,355)	(25,551)
Unrealized losses related to Eagle Rock Gas Services	(538)	-	(538)	-
Restricted unit compensation expense	1,507	1,294	3,441	4,652
Non-cash mark-to-market Upstream imbalances	(107)	102	(123)	(465)
Discontinued operations, net of tax	197	(166)	(210)	(43,811)
Other income	-	(21)	-	(99)
Other operating income	-	-	(2,893)	-
ADJUSTED EBITDA	$62,177	$32,678	$146,419	$94,945

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Amortization of commodity derivative costs	-	-	-	$3,078