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Interstate Pipelines | Exploration & Production | Midstream

Investor & Analyst Meeting

May 24, 2011

D E P E N D A B L E N A T U R A L G A S

Cautionary Statement Regarding Forward-Looking Statements

This presentation release includes certain forward-looking statements and projections. The company has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this release, including, without limitation, our ability to execute our strategy of selling assets to El Paso Pipeline Partners, L.P.; our ability to pay dividends declared; changes in unaudited and/or unreviewed financial information; volatility in, and access to, the capital markets; our ability to implement and achieve objectives in our 2011 plan and updated guidance, including achieving our earnings and cash flow targets; the effects of any changes in accounting rules and guidance; our ability to meet production volume targets in our Exploration and Production segment; the uncertainty of estimating proved reserves and unproved resources, the future level of service and capital costs; the availability and cost of financing to fund our future exploration and production operations; the success of our drilling programs with regard to proved undeveloped reserves and unproved resources; our ability to successfully identify new Midstream opportunities; our ability to comply with the covenants in our various financing documents; our ability to obtain necessary governmental approvals for proposed pipeline and E&P projects and our ability to successfully construct and operate such projects; the risks associated with recontracting of transportation commitments by our pipelines; regulatory uncertainties associated with pipeline rate cases; actions by the credit rating agencies; the successful close of our financing transactions; credit and performance risk of our lenders, trading counterparties, customers, vendors and suppliers; changes in commodity prices and basis differentials for oil, natural gas, and power; general economic and weather conditions in geographic regions or markets served by the company and its affiliates, or where operations of the company and its affiliates are located, including the risk of a global recession and negative impact on natural gas demand; the uncertainties associated with governmental regulation; political and currency risks associated with international operations of the company and its affiliates; competition; and other factors described in the company's (and its affiliates') Securities and Exchange Commission filings. In addition, there are a variety of risks and other factors associated with our proposed spin-off of our Exploration and Production segment that could negatively impact our ability to implement the transaction and/or its project results, including, without limitation, risks typically inherent in spin-off and related transactions of this type; our ability to pay the targeted initial dividend and to increase the dividend thereafter for our pipeline and midstream businesses, our ability to execute on our debt reduction strategy; risks associated with the level of debt to be incurred by the Exploration and Production segment; the availability of the capital markets for raising capital and additional debt; once separated, the ability of the businesses to successfully operate independently; our ability to obtain all necessary regulatory approvals to implement the separation of the businesses, including, but not limited to, confirmation of the tax-free nature of the transaction; and the receipt of final approval of our board of directors of the separation and related transactions. As a result, there is a risk that the proposed separation may not be completed as contemplated, including the risk that there may be material changes in timing and/or terms of the transaction or that the transaction may not be completed at all. While the company makes these statements and projections in good faith, neither the company nor its management can guarantee that anticipated future results will be achieved. Reference must be made to those filings for additional important factors that may affect actual results. The company assumes no obligation to publicly update or revise any forward-looking statements made herein or any other forward-looking statements made by the company, whether as a result of new information, future events, or otherwise.

Certain of the production information in this presentation includes the production attributable to El Paso's 48.8 percent interest in Four Star Oil & Gas Company ("Four Star"). El Paso's Supplemental Oil and Gas disclosures, which are included in its Annual Report on Form 10-K, reflect its interest in the proved reserves of Four Star separate from its consolidated proved reserves. In addition, the proved reserves attributable to its interest in Four Star represent estimates prepared by El Paso and not those of Four Star.

Cautionary Note to U.S. Investors – Investors are urged to closely consider the disclosures and risk factors in our Forms 10-K and 10-Q, available from our offices or from our website at http://www.elpaso.com, including the inherent uncertainties in estimating quantities of proved reserves.

Schedule—Estimated Time (EST)

8:00 a.m.	**INTRODUCTION** Bruce Connery ….. Vice President, Investor & Media Relations Doug Foshee …….. Chairman, President & Chief Executive Officer	*20 min*
8:20 a.m.	**FINANCIAL OVERVIEW** J. R. Sult ……..Exec. Vice President & Chief Financial Officer	*10 min*
8:30 a.m.	**MACRO VIEW** Pat Johnson ……. Vice President, Strategy	*20 min*
8:50 a.m.	**PIPELINES** Jim Yardley ……Chairman, Pipeline Group	*30 min*
9:20 a.m.	**MLP STRATEGY** J. R. Sult ……..Exec. Vice President & Chief Financial Officer	*10 min*
9:30 a.m.	**BREAK**	*15 min*
9:45 a.m.	**MIDSTREAM** Mark Leland …… President, Midstream Group	*15 min*
10:00 a.m.	**EXPLORATION & PRODUCTION** Brent Smolik ……President, Exploration & Production	*45min*
10:45 a.m.	**SUMMARY AND Q&A**	*30 min*
11:15 a.m.	**MEET WITH MANAGEMENT**	*30 min*
11:45 a.m.	**MEETING CONCLUDES**	

Defining Our Purpose

El Paso Corporation provides natural gas and related energy products in a safe, efficient, and dependable manner

Vision & Values

the **place** to work
the **neighbor** to have
the **company** to own

El Paso…
From Survival to An Enduring Enterprise

2003	2011+
Damaged brand	Purposeful company
Diffused business	Highly focused
Bloated overhead	Efficient
Leverage on the precipice	Durable balance sheet
Making payroll	Looking over horizon
From pillar-to-post	Execution-focused
Co. pride at rock bottom	Values driven Team EP

Well-positioned for next 80+ years

Pipelines…
From Good to Great

2003	2011+
Carlsbad recovery	Industry safety leader
Reasonable growth prospects	Best backlog in service
Purchasing department	Supply chain management
Good pipeliners	Superior execution track record
Tactically focused	Much more strategic
No MLP	Top-performing MLP

Biggest, best pipeline franchise

Exploration & Production
Interesting Journey, Great Destination

2003	2011+
High-risk strategy	High repeatability
Disadvantaged portfolio	Cored-up
Poor execution	Top-tier
Low inventory	Competitive inventory
High-cost	Low-cost

A top-tier E&P company

Midstream…
A Successful Business Redux

2003	2011+
Outstanding Midstream Co.—Sold 2004	
Deep midstream knowledge	Retained
	Re-entry 2010
	Important starter kit
	Focused strategy
	Great partner
	Outstanding growth prospects

A synergistic new leg on the stool

We're On A Great Path

- Financial strength restored
- Free cash and investment grade profile in 2012
- Pipes complete backlog, but more growth to come
- E&P a top-tier competitor
  - Deep inventory in core areas
  - Growing oil volumes
- Midstream adds new growth vehicle
- MLP strategy creating value for EP & EPB

Fundamental Interlocking Strategic Questions

- Do our businesses have greater capacity to create value together or apart?
- Will investors value the businesses more highly as independent entities – now and over time?

We've answered these questions

We Intend to Separate the Business

- Unanimous conclusion of Mgmt. and Board
- Tax-free spin of E&P company
- Will not require shareholder vote
- Subject to:
  - IRS tax ruling and other customary approvals
  - Finalization of capital structure
  - Final Board approval
  - Market conditions
- Target completion by year-end 2011

We will create two enduring businesses with similar DNA - Zygosity

Why Do this? And Why Now?

- Because it is the right thing to do for shareholders
- Structural impediments gone
  - Balance sheet in shape
  - Pipeline backlog largely complete
  - E&P well positioned & growing
- Recent valuations have shifted burden of proof
- Exciting value creation for the company's businesses
- Allows investors to assess businesses independently
- Simplifies and focuses equity stories
- Greater management focus on each company

Value Proposition E&P Spinco

- Large stand-alone independent
- Well capitalized
- ~20% EBITDA growth in 2012[1]
- Inventory – large, oily, profitable, repeatable
- Low-cost in core areas
- Mature execution model
- Excellent growth/returns outlook
- Strong leadership
  - Doug Foshee - Non-Executive Chairman
  - Brent Smolik - CEO
  - Dane Whitehead - CFO

E&P industry leader

[1] Assumes E&P capital consistent with 2011 levels and forward 2012 prices as of May 20, 2011

Value Proposition – Pipelines & Midstream

- Premier interstate pipeline franchise
- Growing midstream business
- Best in class MLP/100% owned high-growth GP
- Substantial cash generation & growth
- Pipeline/Midstream synergies
- Targeting $0.60 dividend in 2012
- Targeting low double-digit dividend growth
- Seasoned management team remains
  - Doug Foshee remains Chairman & CEO

Targeting 14% + total return
Strong competitor in corporate yield space

Our Futures are Bright – Building Better Mouse Traps

- Two high-quality companies
- Both well capitalized
- Both with great futures
- Each more nimble
- Motivated, unified management
- Substantial and sustainable valuation uplift
- Target completion by year end

We will continue to outperform

Financial Overview

J. R. Sult
Executive Vice President & Chief Financial Officer

Benefits of Separation

- Greater management focus on distinct business strategies
  - Growth-oriented E&P business
  - Yield-oriented Pipeline and Midstream businesses with substantial and growing dividend
- Credit enhancing to El Paso Corporation
- Greater flexibility to grow businesses supported by separate equity currencies
- Independent capital structures & credit profiles = lower cost of capital
- Improved capital markets access
- Increased flexibility and efficiency in capital allocation

The Balance Sheet Will Be Ready

- Our drive toward investment grade profile has been unwavering
- Key drivers:
  - MLP drop down strategy
    - Exceeding expectations
    - Expect more to come
  - Growth in businesses

Key barrier will be behind us

Capital Structure & Credit Profile

El Paso Corp.

- Largest pure-play interstate natural gas transportation company
  - Investment-grade business and financial characteristics
- Leverage will be comparable to investment-grade peers and will improve
  - Complete backlog
  - Continue MLP strategy

E&P Co.

- Well-positioned to prosper independently
  - Substantial scale and operational diversification
  - Multi-year inventory of low-risk growth opportunities
  - Growing oil weighting
  - Expect 2012 EBITDA up ~20%[1]
- Leverage consistent with key competitors
  - $2B - $2.25B net debt

Stand-alone capitalization and credit profile will drive lower cost of capital

[1] Assumes E&P capital consistent with 2011 levels and forward 2012 prices as of May 20, 2011

Next Steps

- Submit IRS tax ruling
- Finalize capital structure
  - E&P company debt
  - Liability management
  - Credit facilities
- SEC filings
- Separation agreements
- Final BOD approval

Target completion by YE 2011

2011 Financial Highlights

- Financial & operational results ahead of schedule
- Continued MLP drop-down execution
  - Successfully completed 6th transaction
  - Funding debt reduction
- Additional price risk management

Good progress on all fronts

Updated 2011 Guidance[1]

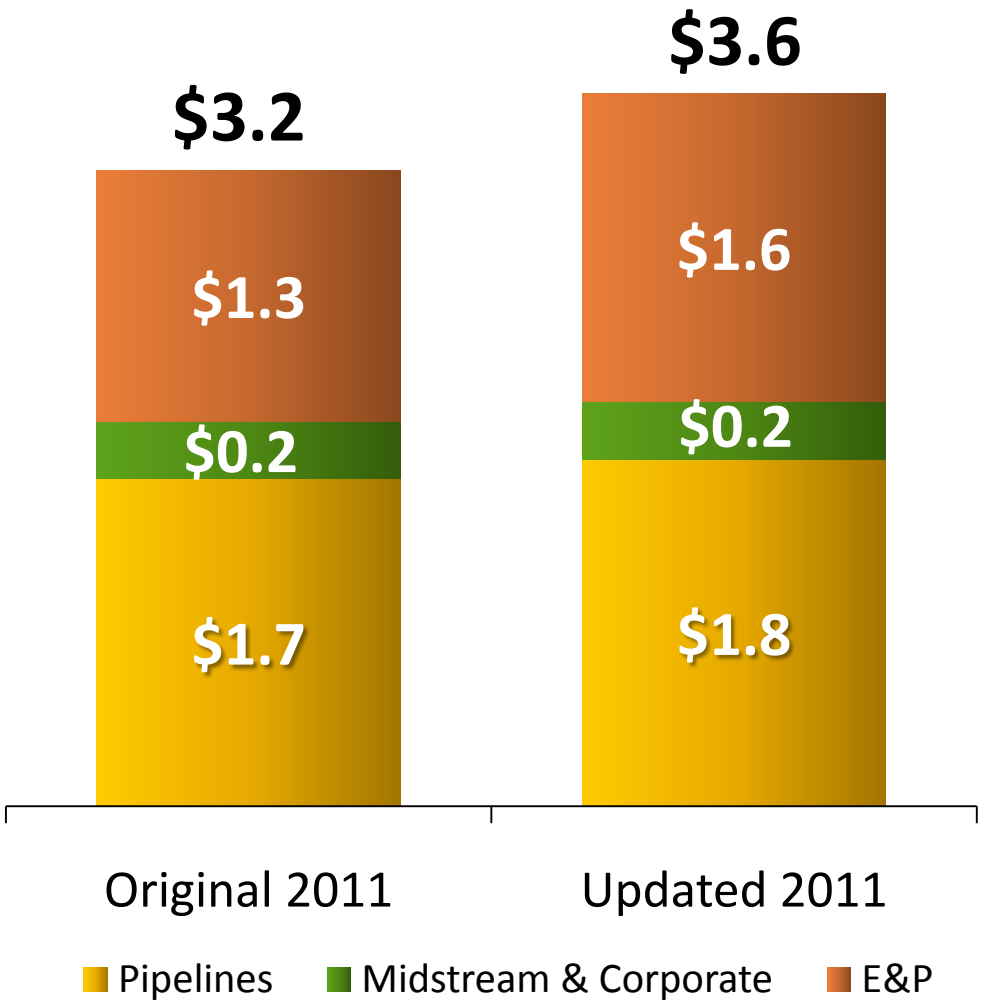
	Original	Updated[1]
Adjusted EPS	$0.90–$1.05	$1.00–$1.10
Operating cash flow ($B)	$2.1–$2.3	$2.2–$2.4
Capital ($B)	$3.2	$3.6
Adj. Segment EBIT ($B)	$2.2–$2.4	$2.3–$2.5
Adj. Segment EBITDA ($B)	$3.3–$3.5	$3.4–$3.6

Production growth & prices driving higher earnings and operating cash flow

[1] Updated guidance assumes $4.50/MMBtu (NYMEX) and $107/Bbl (WTI)

Updated 2011 Capital Program

$ Billions



- Additional capital for Eagle Ford Central
  - Activity not inflation
  - Funded by increased cash flow & non-core divestitures
- Higher 2011 production and exit rate
- Pipelines updated for Ruby

Attractive Hedge Positions

Natural Gas Production Hedges				
Year	Volume (Bcf)	% of U.S. Gas Production	EP Avg. Hedge Price[1] ($/MMBtu)	Current Market Prices (NYMEX)
2011	153	85%	$5.74	$4.31
2012	105	40%	$6.01	$4.87

Oil Production Hedges				
Year	Volume (MMBbl)	% of Total Oil Production	EP Avg. Floor/Ceiling ($/Bbl)	Current Market Prices (WTI)
2011	4.3	75%	$85.99 – $91.88	$99.03
2012[2]	6.4	90%	$93.30 –$112.76	$98.32
2012 (at 3/31)	4.9	70%[2]	$91.31–$104.71	

[1]Represents the average floor price for 2011 and the average fixed price for 2012.
[2]Excludes 1.46 MMBbl of $95 call options.
Note: NYMEX & WTI pricing is as of May 17, 2011, and hedge positions are as of May 17, 2011. Natural gas production with floors reflects domestic production. 2011 percentages based on remaining 2011E production. 2012 percentages based on FY 2011E production. Expected production includes the company's interest in Four Star.

North American Gas Outlook
(2010–2020)

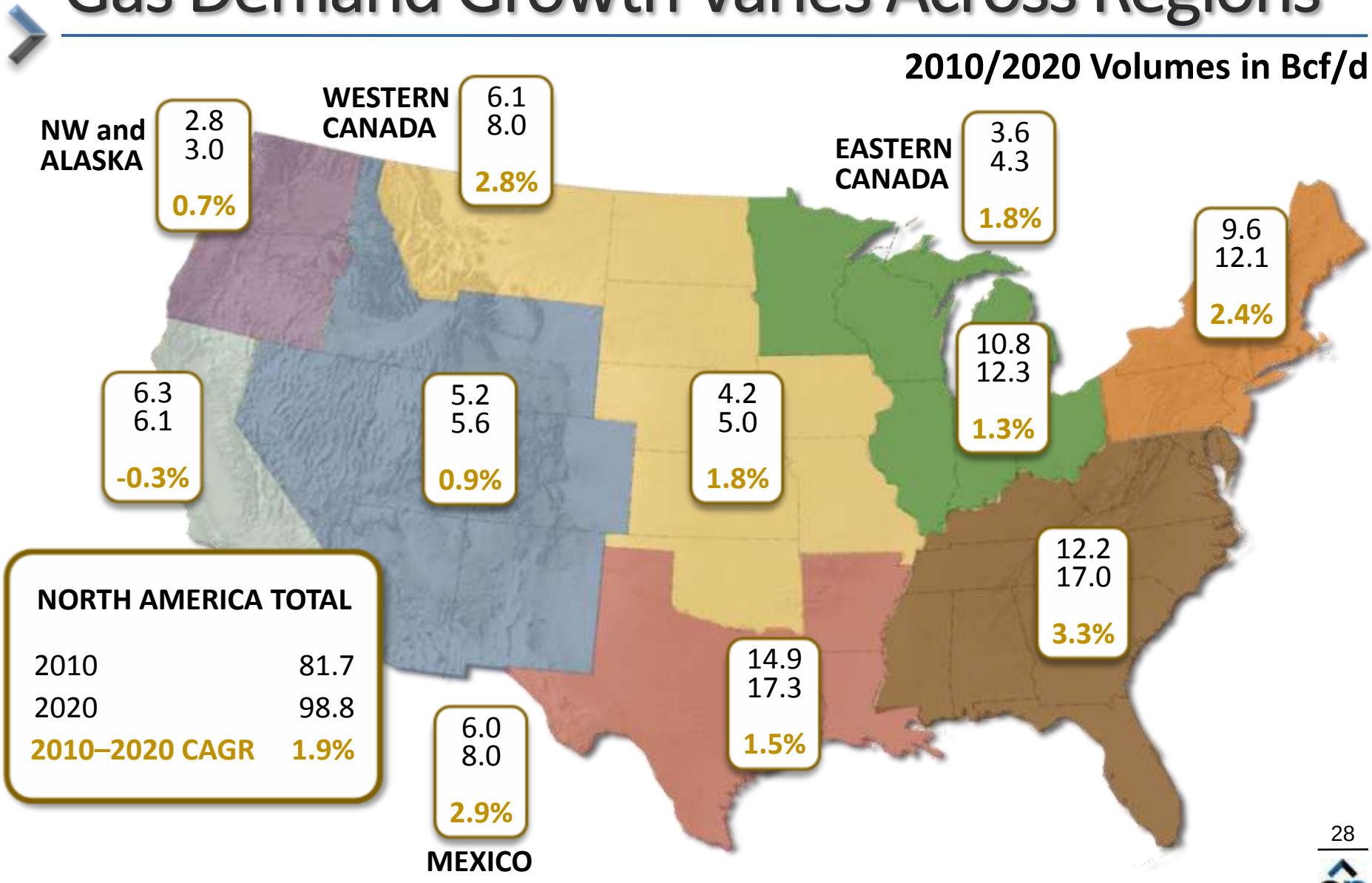
Pat Johnson
Vice President, Strategy

Macro Trends

(2010–2020)

- Growing long-term demand
  - Economy ➡ Electricity ➡ Gas
- Environmental and climate regulation
  - Power: Coal ⬇, Renewables ⬆
- Dramatic supply growth
  - Unconventional production: Shales ⬆, Rockies ⬆
- Changing trade balance
  - Imports: Canada ⬇, LNG ?; Exports: Mexico ⬆, LNG ?, NGL ⬆
- Persistent oil-gas price disparity
  - Resource swaps: Gas ⬌ Liquid
- Infrastructure impetus
  - New sources ➡ New plumbing ➡ New money

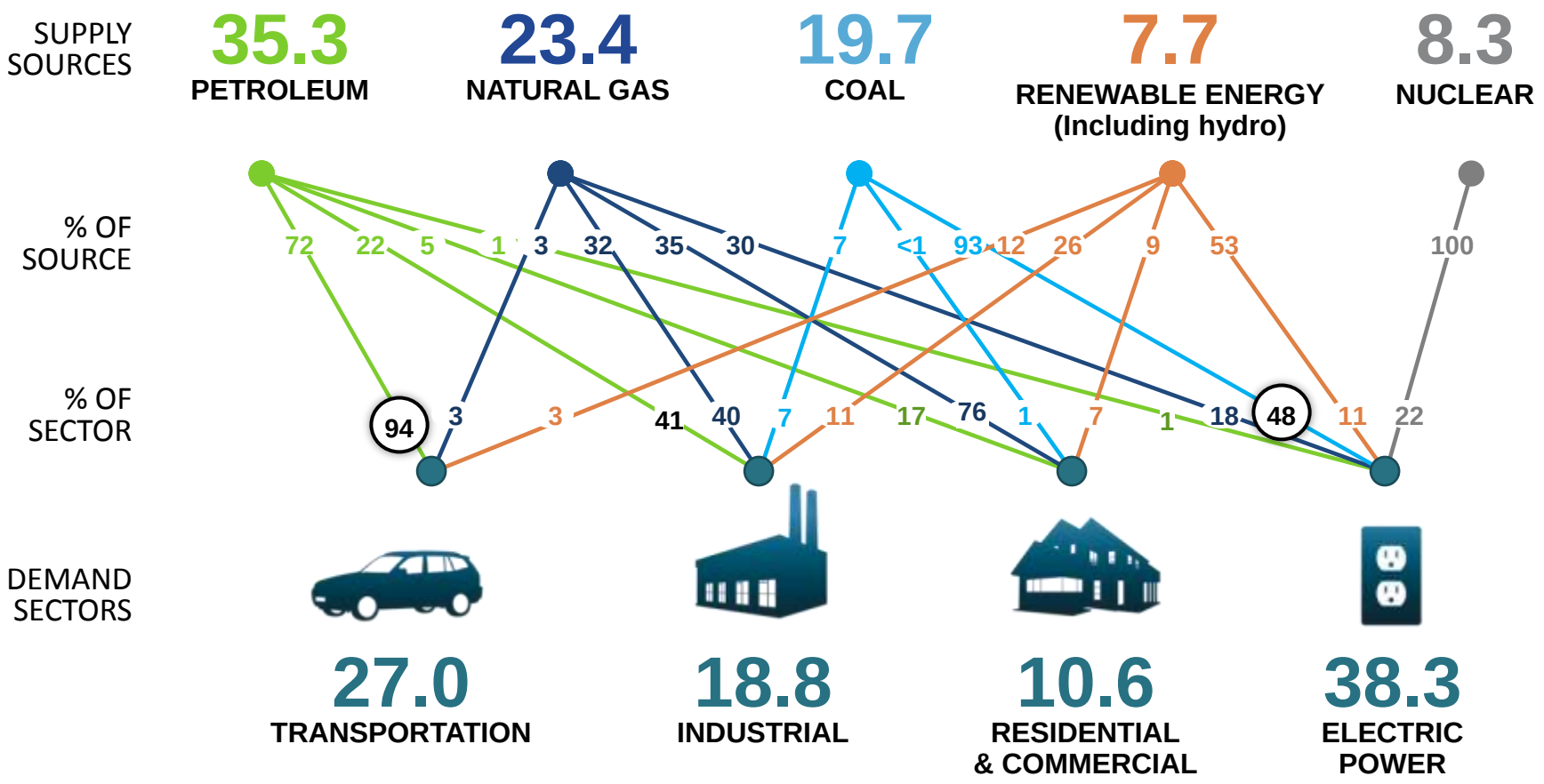
Gas Demand Growth Varies Across Regions



Source: El Paso April 2011 Macro Forecast

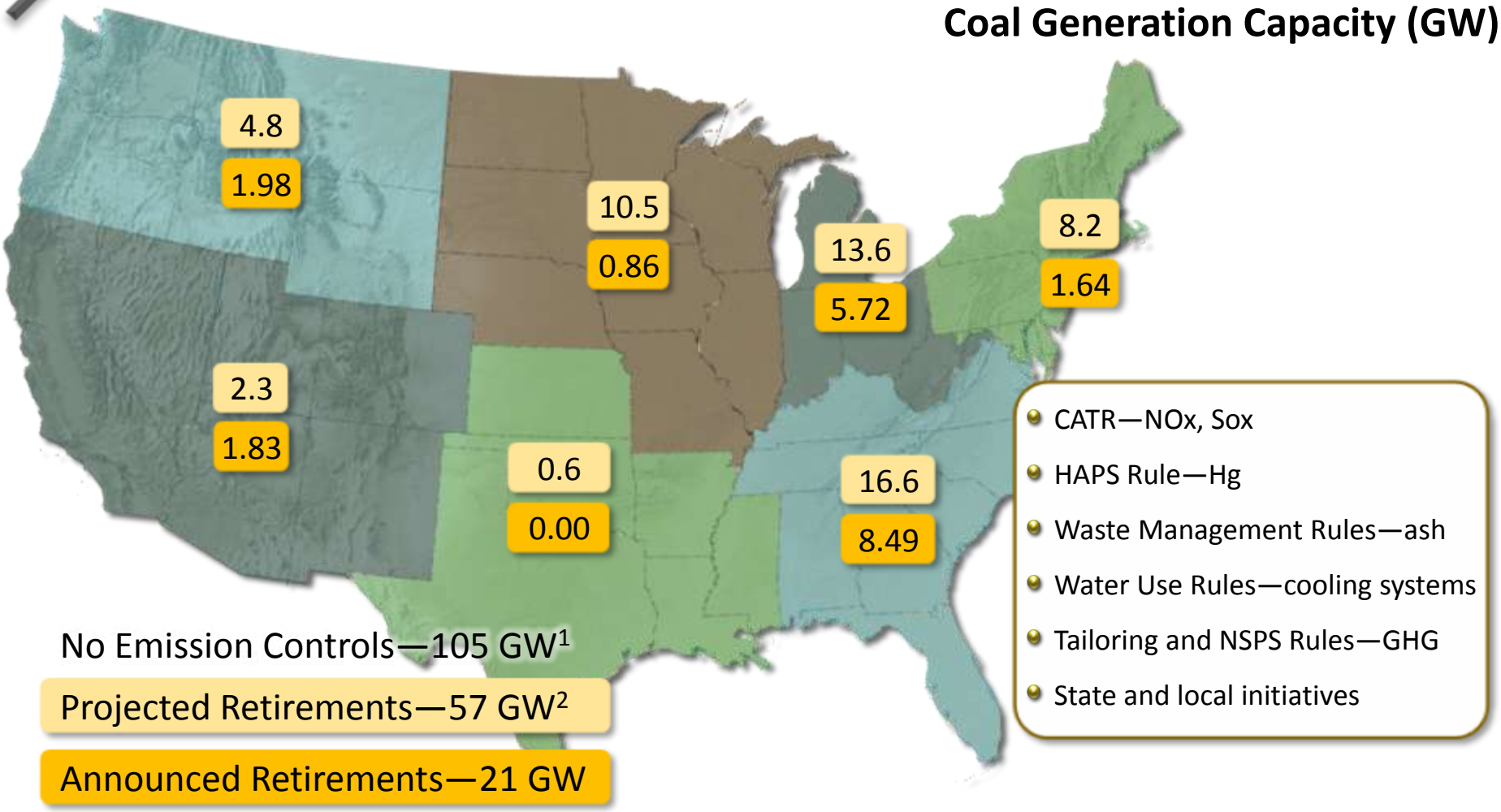
Demand Growth Driven by Market Share

PRIMARY ENERGY CONSUMPTION BY SOURCE & SECTOR, 2009 (Quadrillion Btu)



Source: Energy Information Administration *Annual Energy Review 2009*

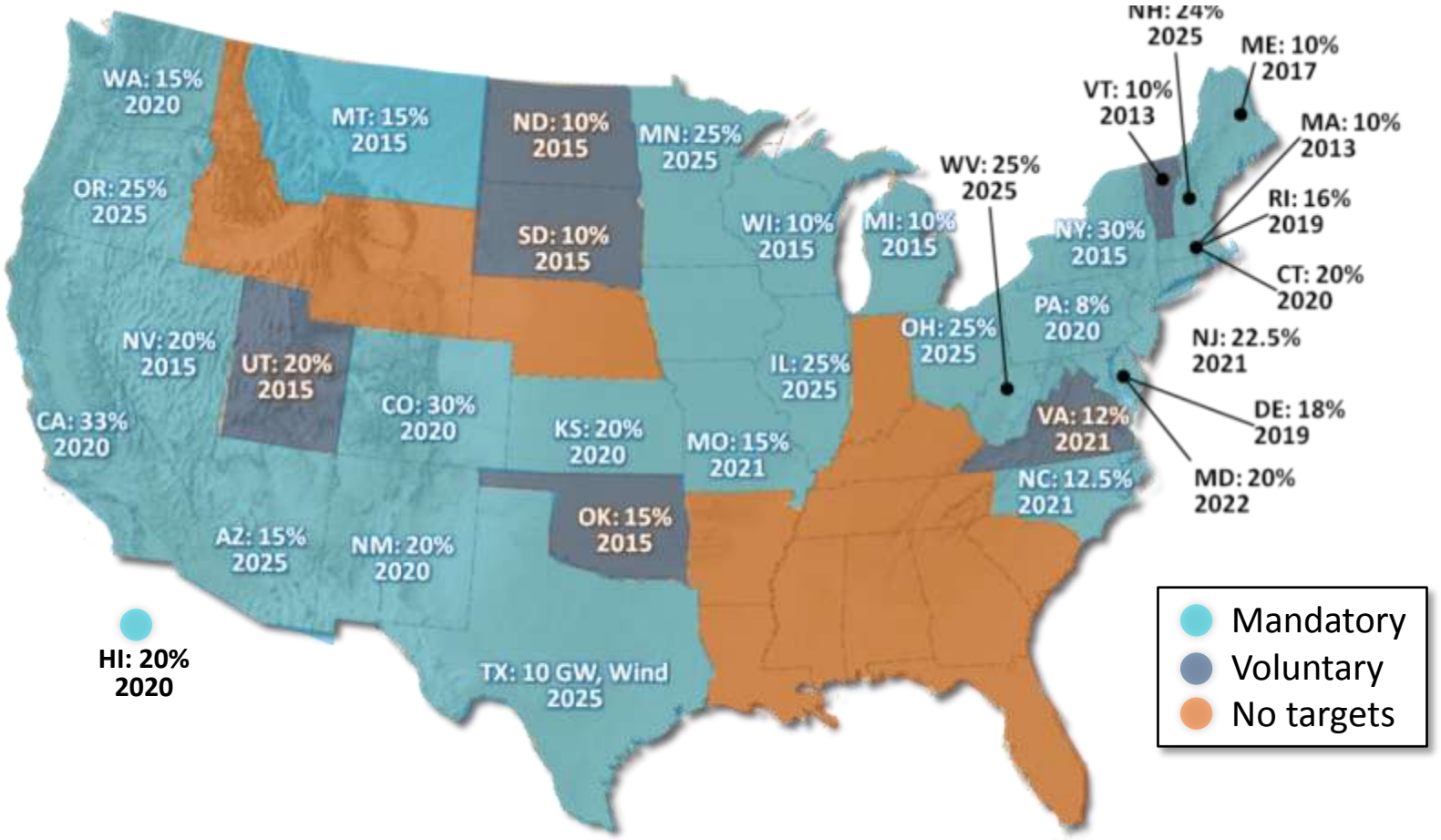
Regulatory Pressures Drive Coal Retirements



9 Bcf/d gas capacity

[1]Ventyx
[2]El Paso estimate

Renewable Power Standards: Bad News, Good News



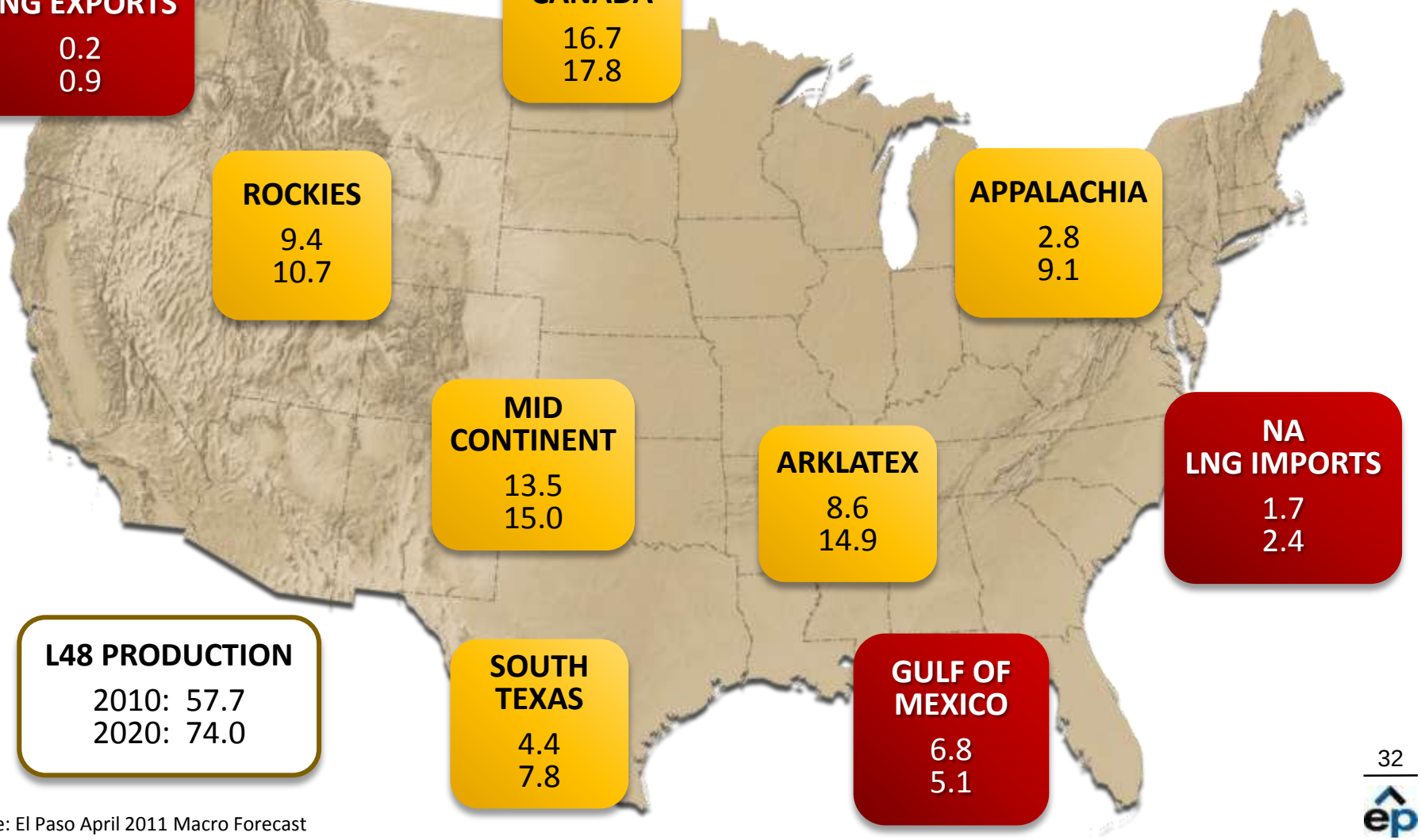
Renewables dampen demand for gas but increase demand for infrastructure

➡ 33 GW generation, 5 Bcf/d pipeline, up to $15 B capital

Sources: RPS - ICF Integrated Energy Outlook, Q1-2011; Gas backup – INGAA Foundation: Firming Renewables

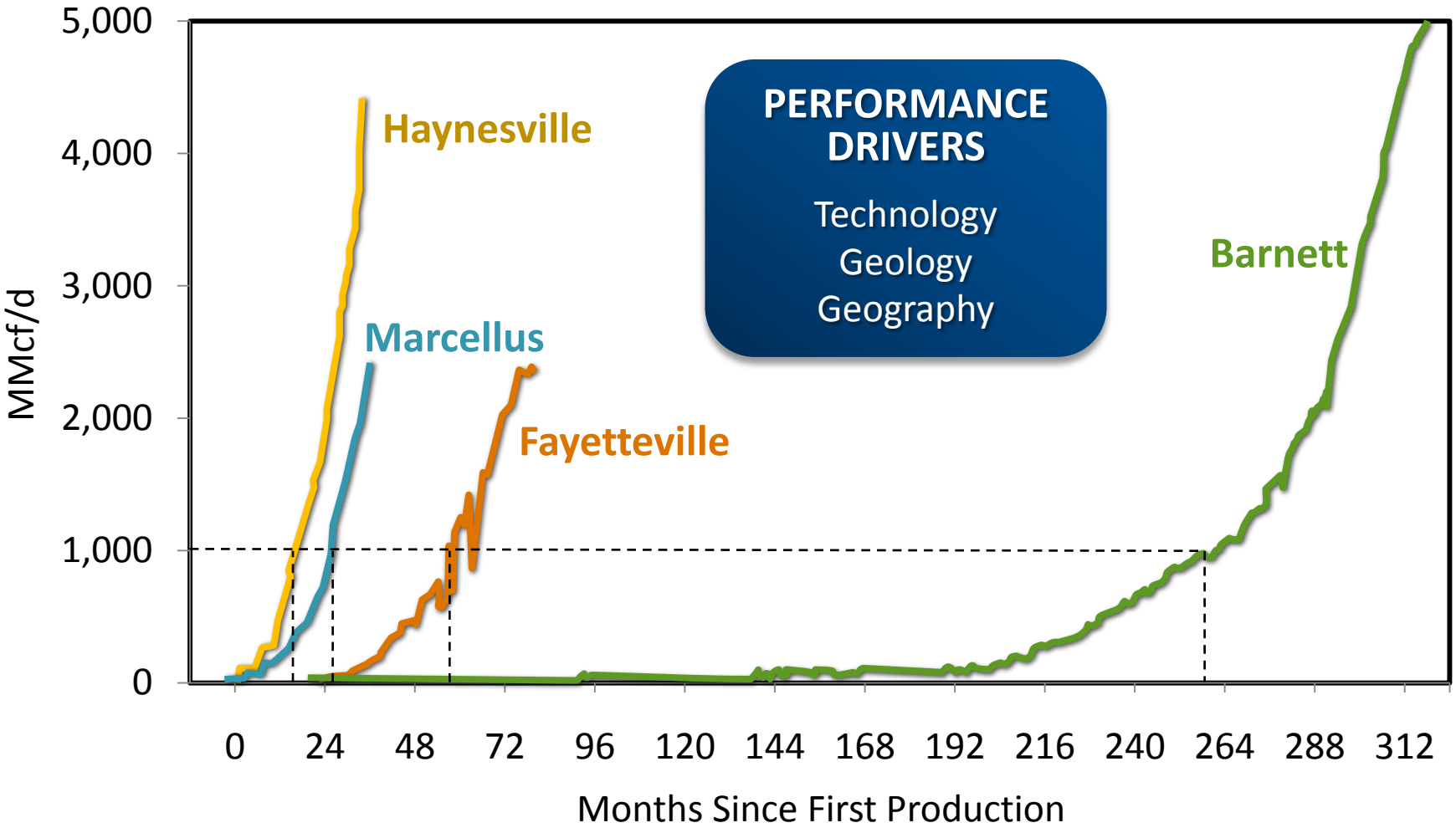
Unconventional Gas Drives Supply Growth

Major Sources (2010/2020) in Bcf/d



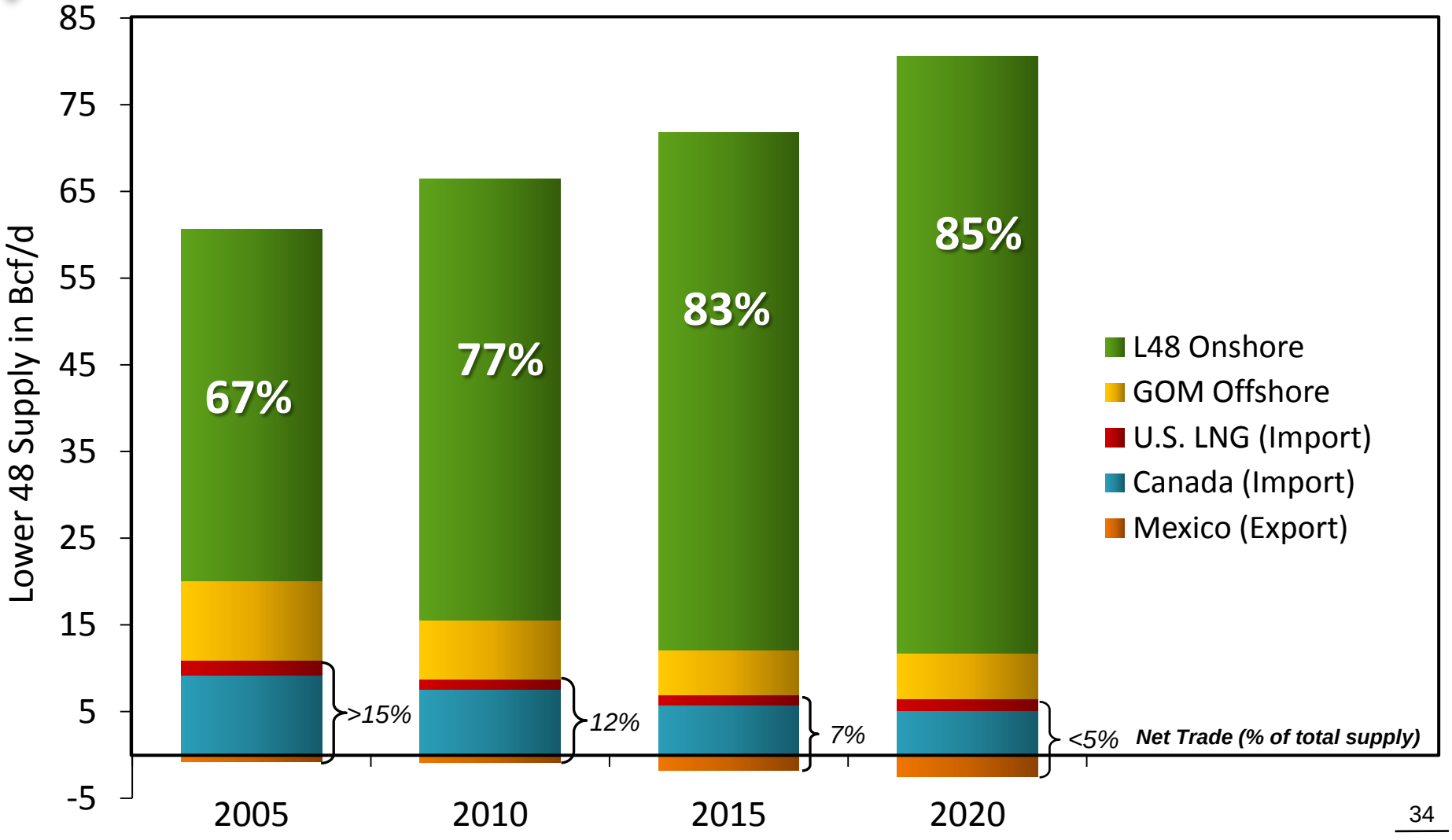
Source: El Paso April 2011 Macro Forecast

Practice Makes Perfect



Source: Wood Mackenzie, State Production Data
Haynesville & Marcellus Time Zero is 1Q 2008; Fayetteville Time Zero is 2004; Barnett Time Zero is 1982

Supply Shifts to Domestic, Onshore Sources



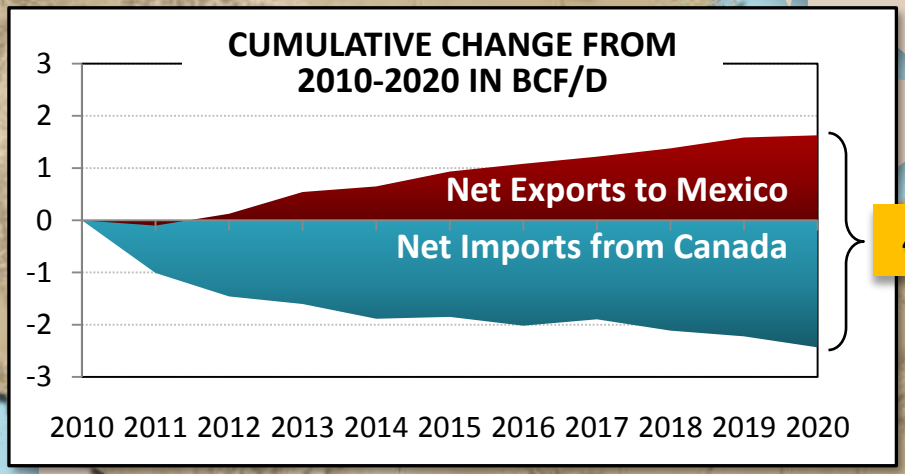
Source: El Paso April 2011 Macro Forecast ; ICF

More Gas Needed Beyond the Borders

CANADA DEMAND ⬆ +2.7
Western Canada Oil Sands
Eastern Canada Coal Generation Retirements
All Canada: GHG Coal Replacement Policy

+0.7

CANADA SUPPLY
WCSB Conventional ⬇ +1.0[1]
Unconventional ⬆
LNG exports



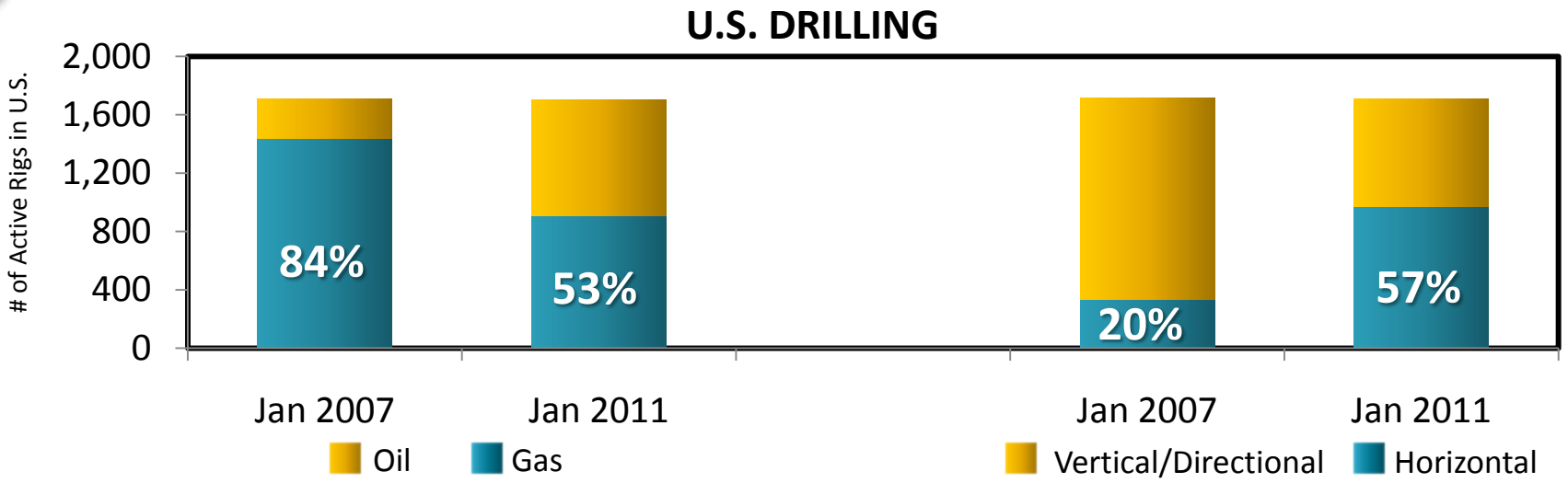
4 Bcf/d

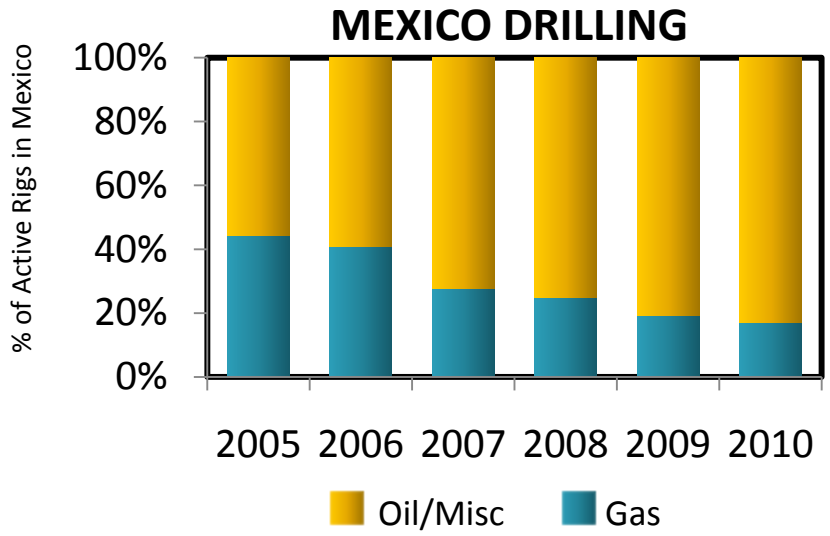
MEXICO DEMAND ⬆ +2.0
Powergen and Industrial Growth
Oil Conversion

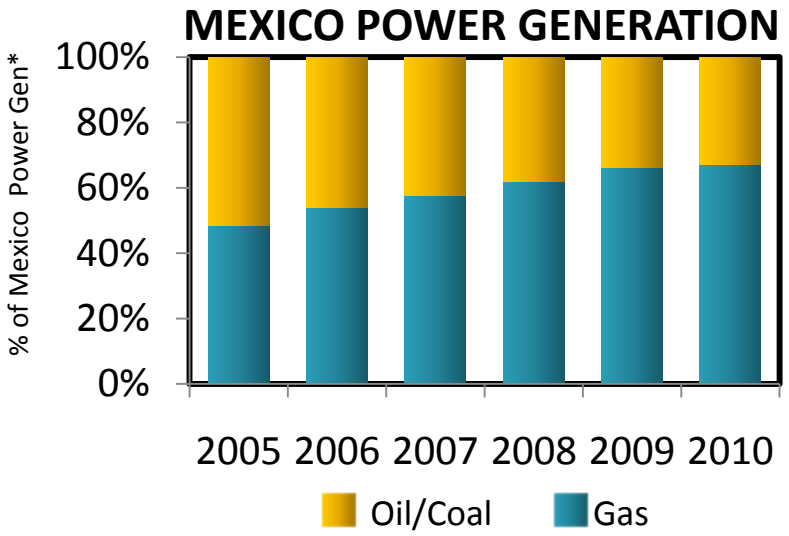
MEXICO SUPPLY +0.4[1]
Gas Production declines as drilling shifts to oil
LNG imports trail demand growth

Source: El Paso April 2011 Macro Forecast
[1]Production + LNG imports

Oil Premium Shifts Resource Preferences



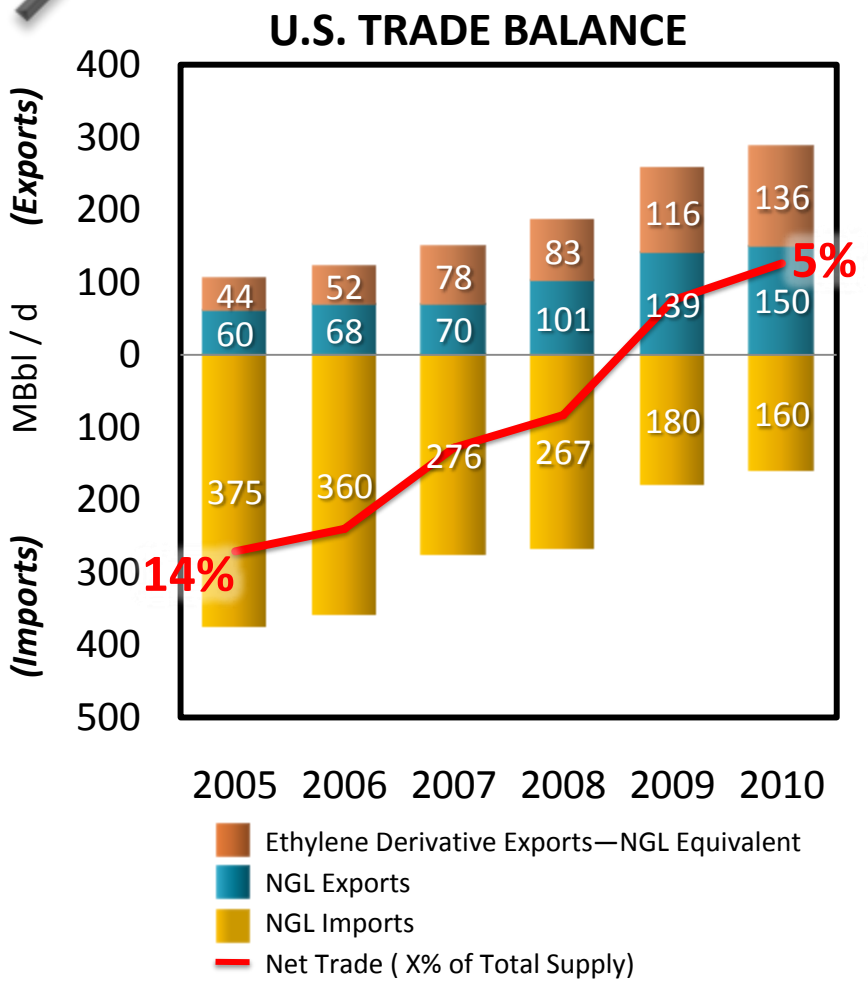


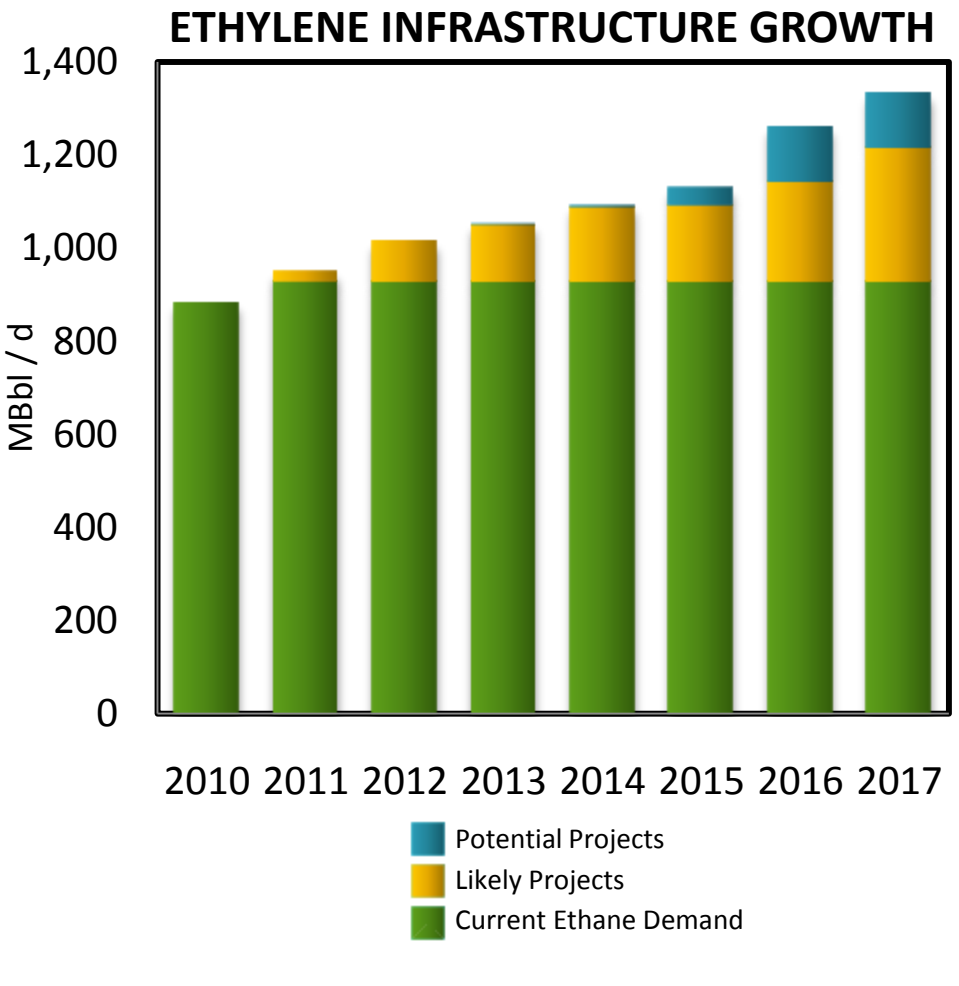


Source: Baker Hughes ; PIRA

* From Combustible Fuel Sources

Reversing the NGL Trade Flow

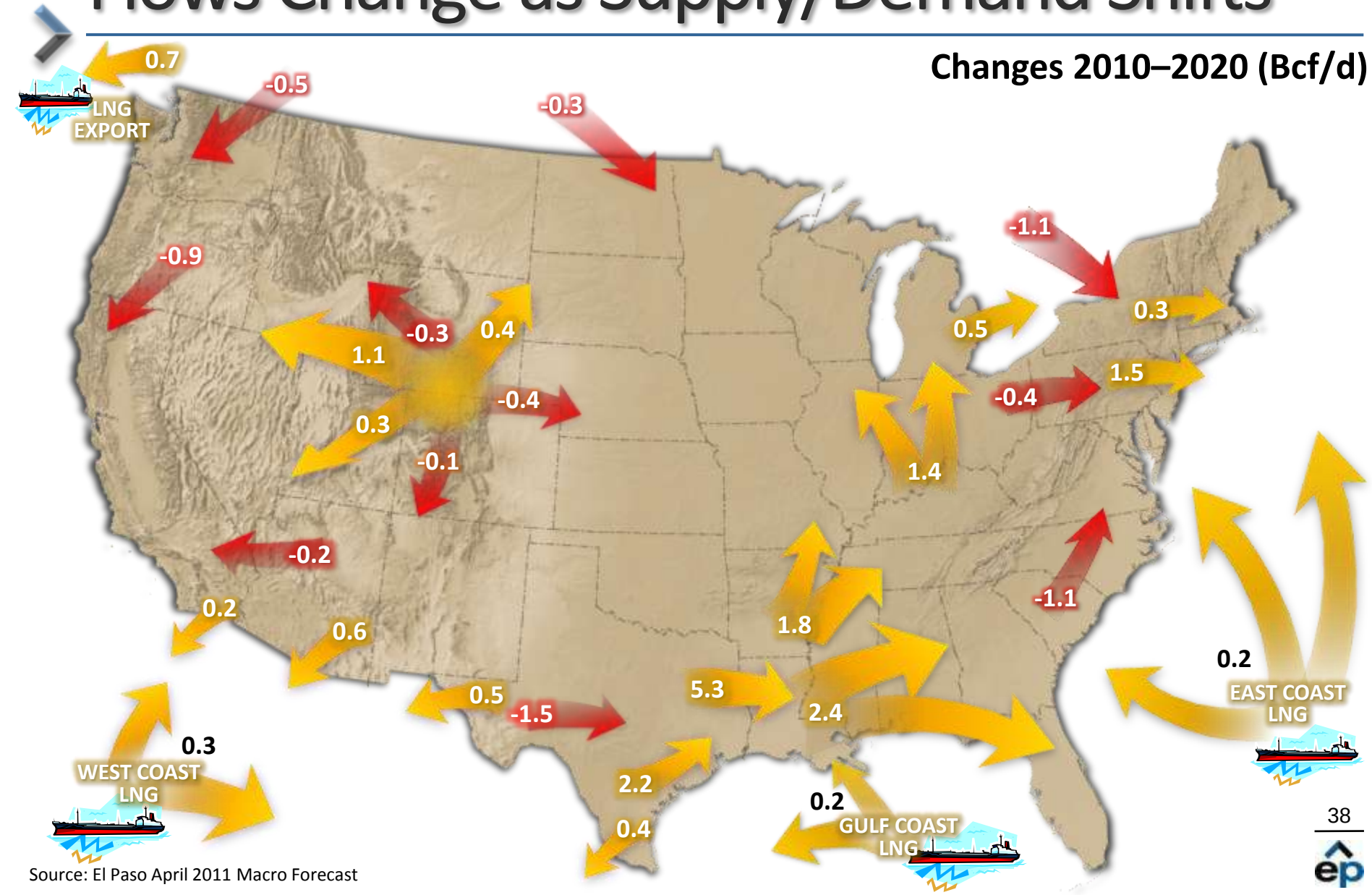




Export trend continues to enlarge market

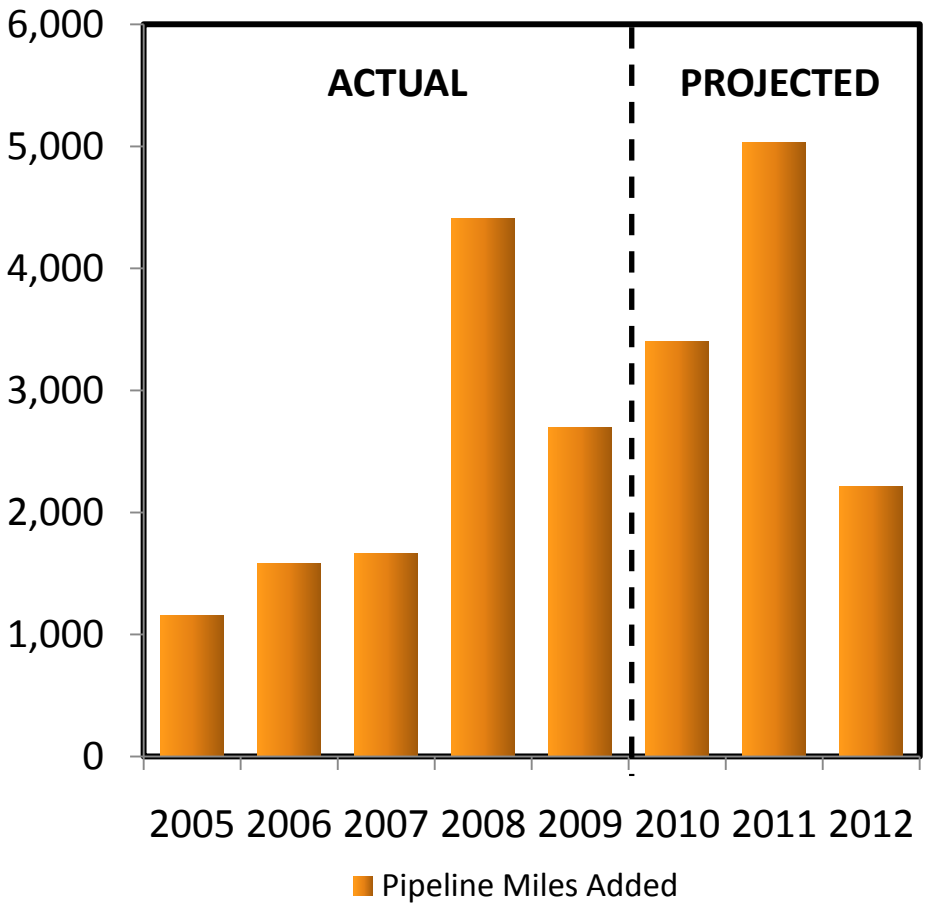
Source: Wells Fargo Securities, LLC

Flows Change as Supply/Demand Shifts



Source: El Paso April 2011 Macro Forecast

Supply/Demand Shifts Drive Investment



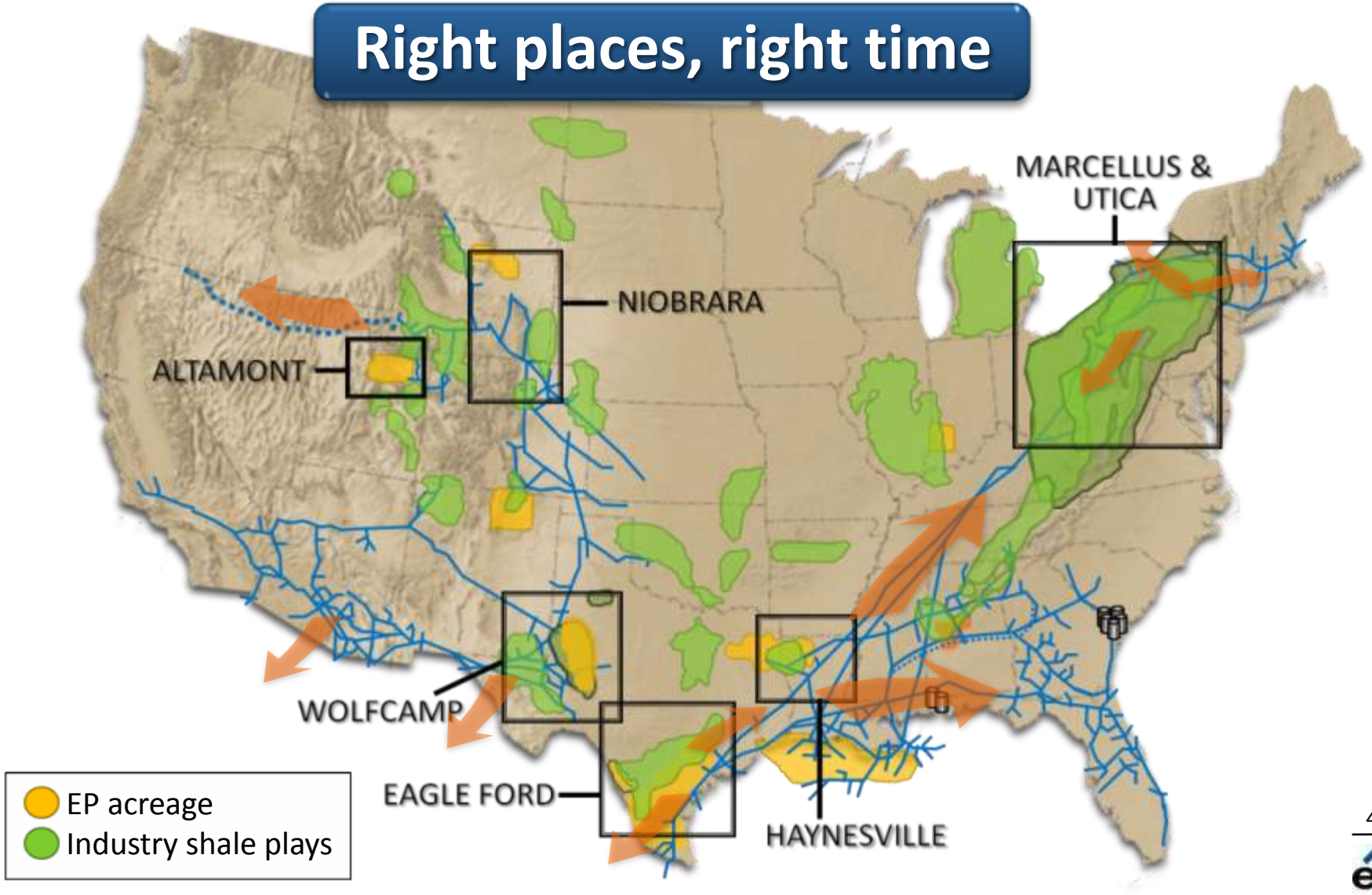
Source: Energy Information Administration

GAS INFRASTRUCTURE ADDITIONS: 2010-2020		$ B
Transmission Mainline	15,000 Miles 27 Bcf/d	48
Connecting Laterals	6,000 Miles	15
Gathering Line	136,000 Miles	17
Pipeline Compression	2,000,000 HP	5
Gas Storage Fields	–	4
Processing Capacity	16 Bcf/d	12

Source: INGAA Foundation, April 2011

Expected capital expenditures of >$100 B

El Paso Opportunities



Pipeline Group

Jim Yardley
President, Pipeline Group

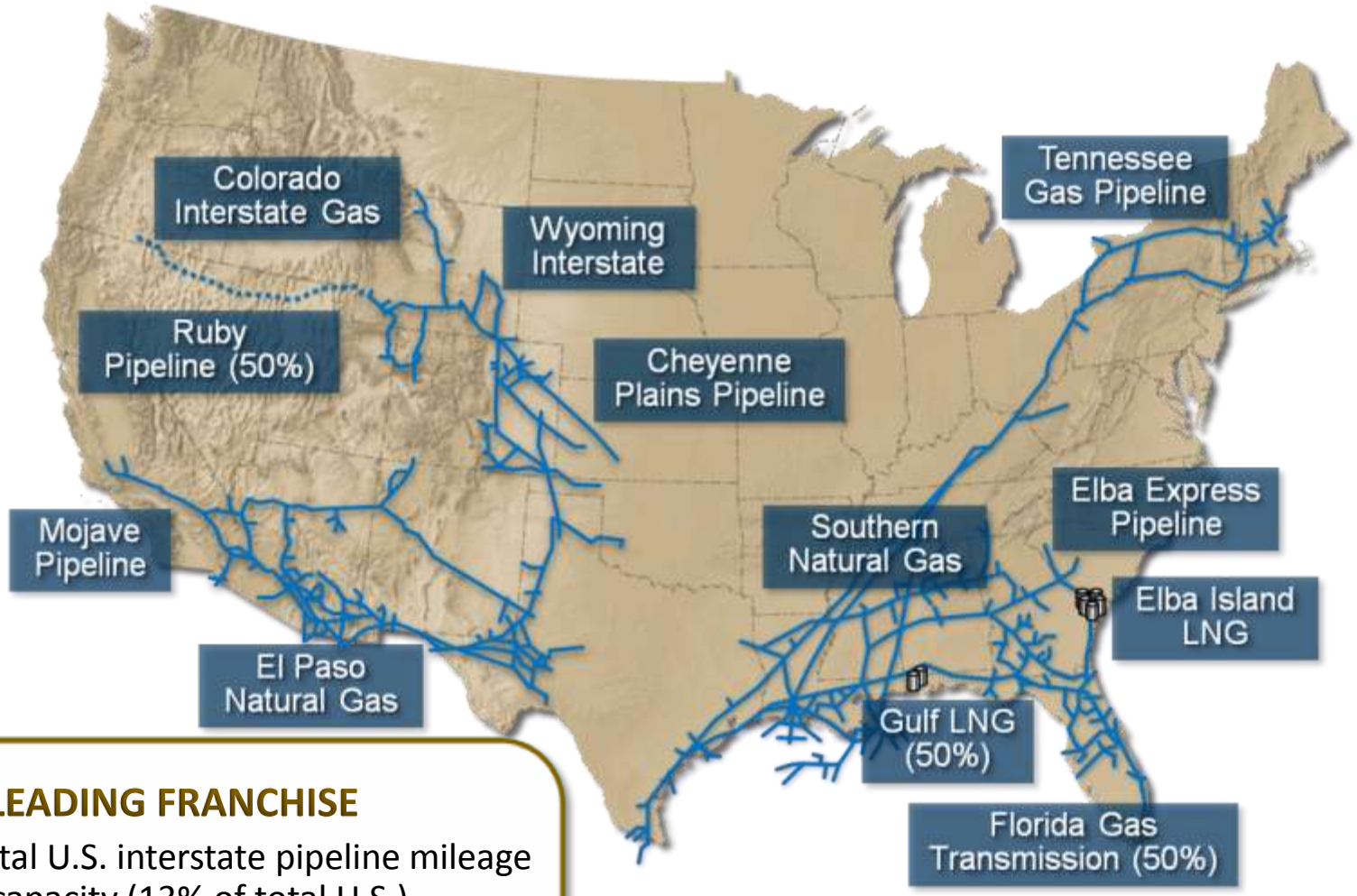
Investment Highlights

UNIQUE FRANCHISE

EXCELLENT FUNDAMENTALS

LONG-TERM GROWTH

Premier Natural Gas Pipeline Network



LEADING FRANCHISE

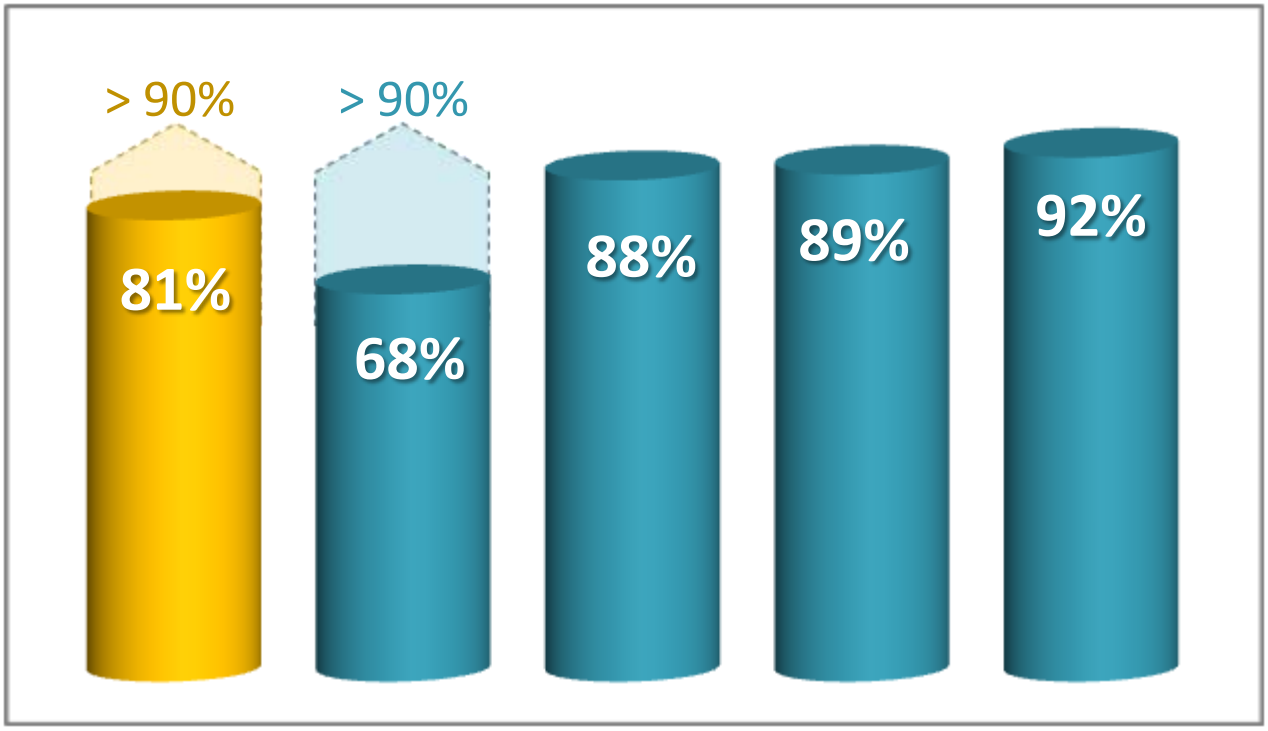
- 19% of total U.S. interstate pipeline mileage
- 28 Bcf/d capacity (13% of total U.S.)
- 17 Bcf/d throughput (26% of gas delivered to U.S. consumers)

Note: As of 12/31/10

Pipeline Safety

- Industry leader
  - Integrity programs go beyond regulations
  - Heavily involved in shaping industry positions
- Strong commitment across organization
  - Established new role—Sr. VP of Pipeline Safety
- Completing system-wide pipeline integrity program
  - >$1 billion invested in past decade

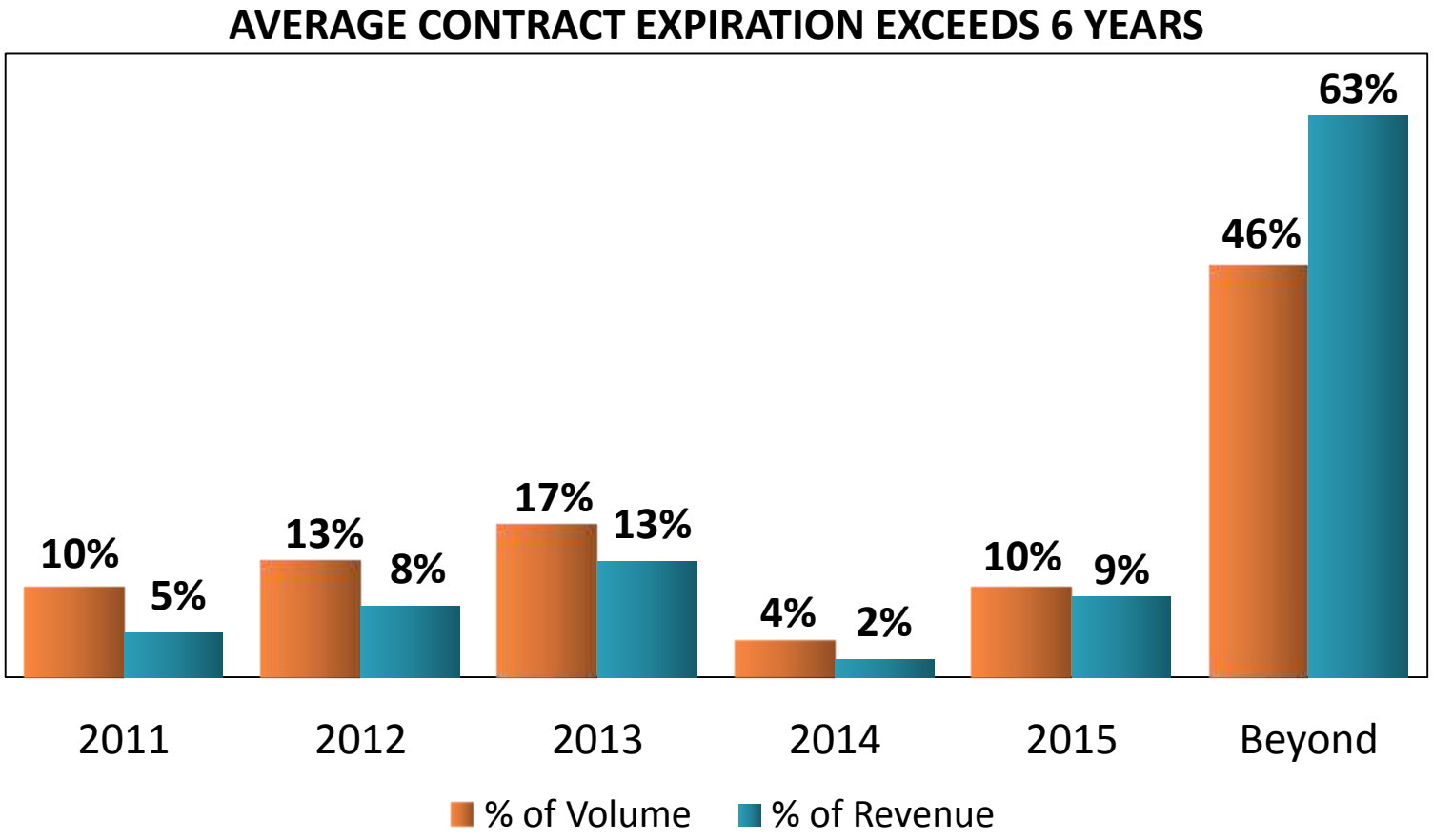
Revenue Stability



Percentage of total revenue increases with TGP rate case

Note: Percentage of total revenue from reservation charges as of 12/31/10

Contract Stability



New expansions increase average contract life

*Average percentage of contract expirations as of 12/31/10. Amounts include Florida Gas Transmission volumes

Regular Rate Cases

TGP	• First case in 15 years • Improves revenue stability
EPNG	• Addresses lower throughput • Higher but competitive rates
CIG	• Just filed early rate settlement
SNG	• Next case expected in 2013
FGT	• Expect to file in 2014

Overall long-term regulated returns

A Unique Pipeline Franchise

What Differentiates EP's Pipeline Group?

NATIONAL FOOTPRINT	Economies of scale; diversity Best positioned for future growth
HIGHLY INTEGRATED SYSTEMS (CONNECTIVITY)	Better base business and opportunity set
SUPERIOR PROJECT EXECUTION	Delivering profitable growth

Unmatched Size and Scope

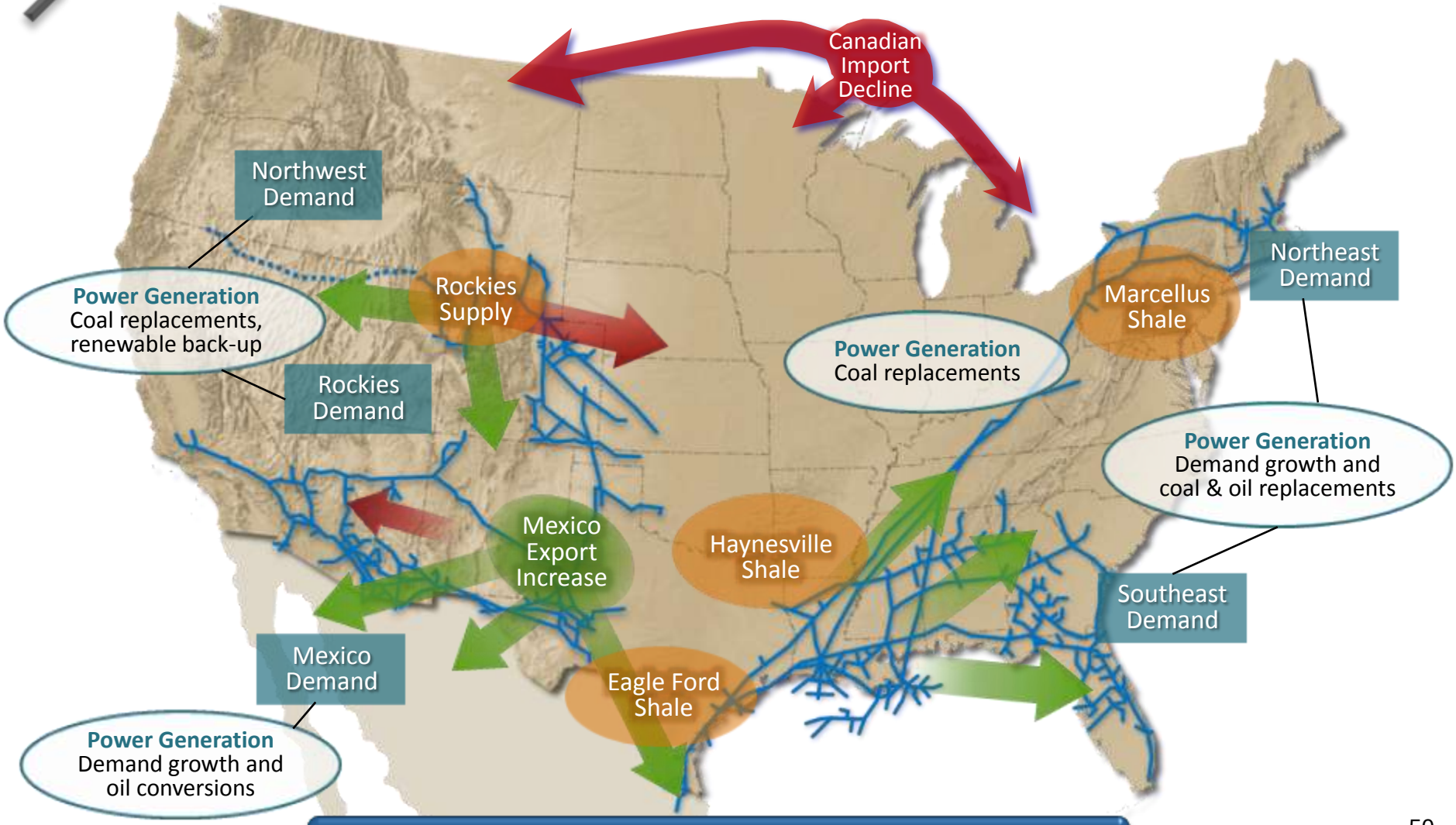
2010	El Paso (EP)	Kinder Morgan (KMI)	Spectra (SE)	Williams (WMB)	Boardwalk (BWP)
Pipeline Segment EBITDA ($B)	$2.0	$0.8	$1.2	$0.9	$0.7
Daily throughput[1] (TBtu/d)	17.5	7.1	7.4	7.7	6.8
Miles of natural gas pipeline[1]	43,100	24,000	14,400	14,600	14,200
States served	27	17	23	20	12

Creates economies of scale and diversity

Note: Domestic statistics based on publicly reported data as of 12/31/10

[1] Includes jointly-owned pipelines, and volumes for KMI and BWP are reported in Bcf/d

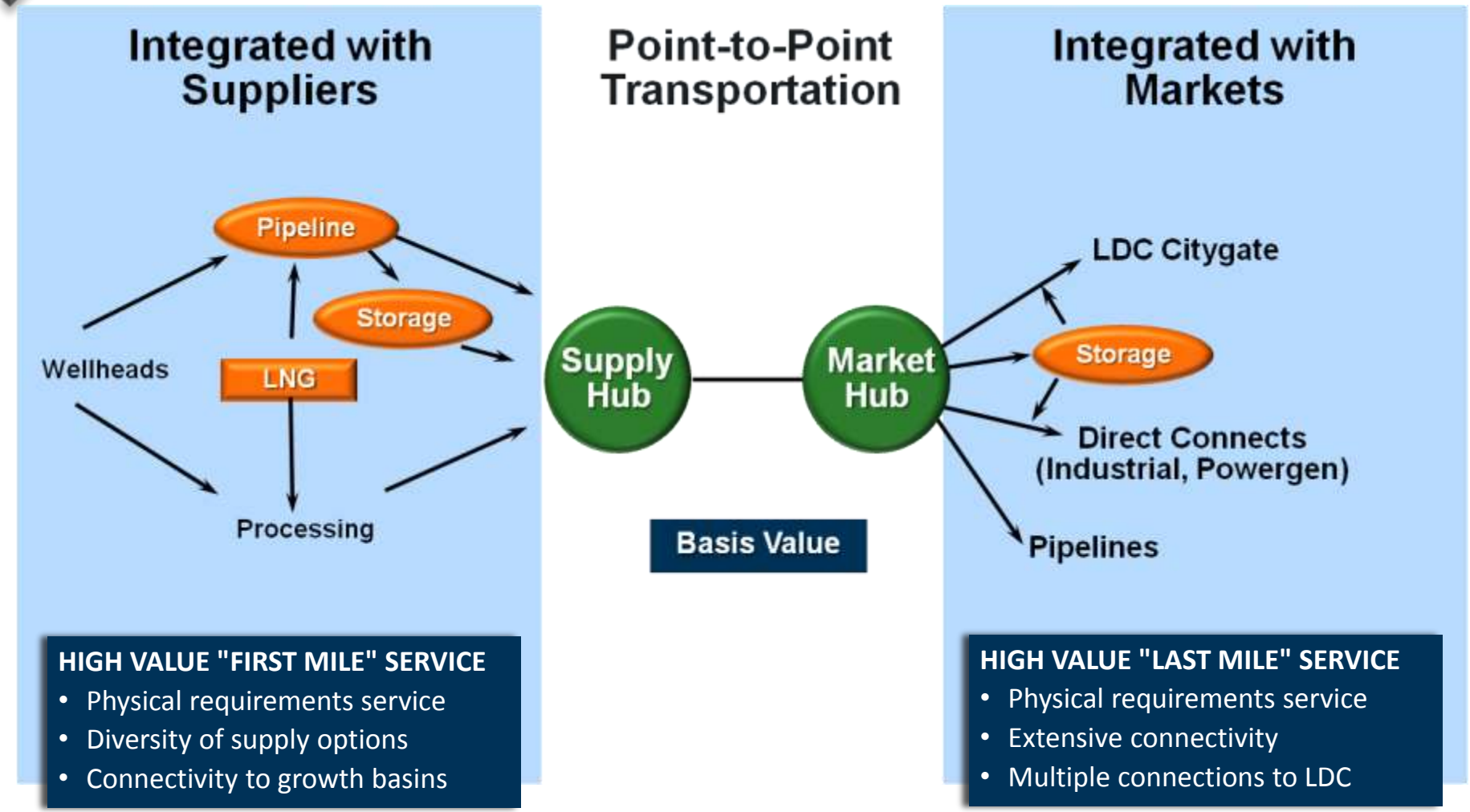
Superior Positioning



In all the best markets/supply basins

Source: El Paso Corporation

Value Driven by Pipeline Connectivity



EP Pipelines more integrated than point-to-point

Highly Integrated Systems

Strong market positions

Superior Project Execution

$ Billions
Proportionate Rate Base[1]

- Project costs within 7%–8% of budget
  - 19 projects (‘07–’11)
- On budget excluding Ruby
- Major projects of competitors 20%–90% over budget
- Effective risk sharing

Yields profitable growth

[1]Includes the company’s proportionate interest in Ruby, Gulf LNG and Florida Gas Transmission
[2] Estimated

2011 Expansion Projects

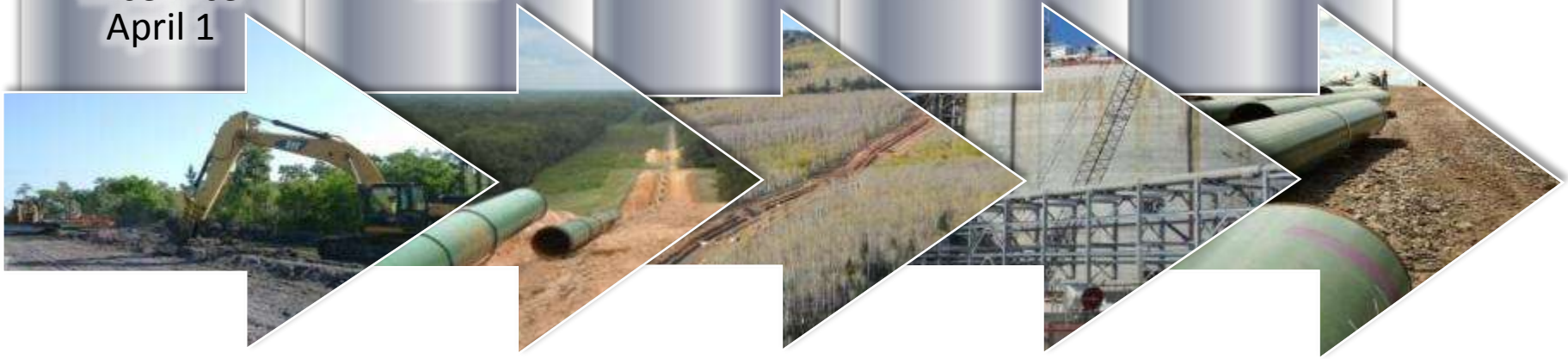
FGT PHASE VIII
✓
Placed in service April 1

SNG SOUTH SYSTEM III[1]
June

RUBY
July

GULF LNG
October

TGP 300 LINE
November



Completing original $8 B backlog
Projects to generate significant cash flow

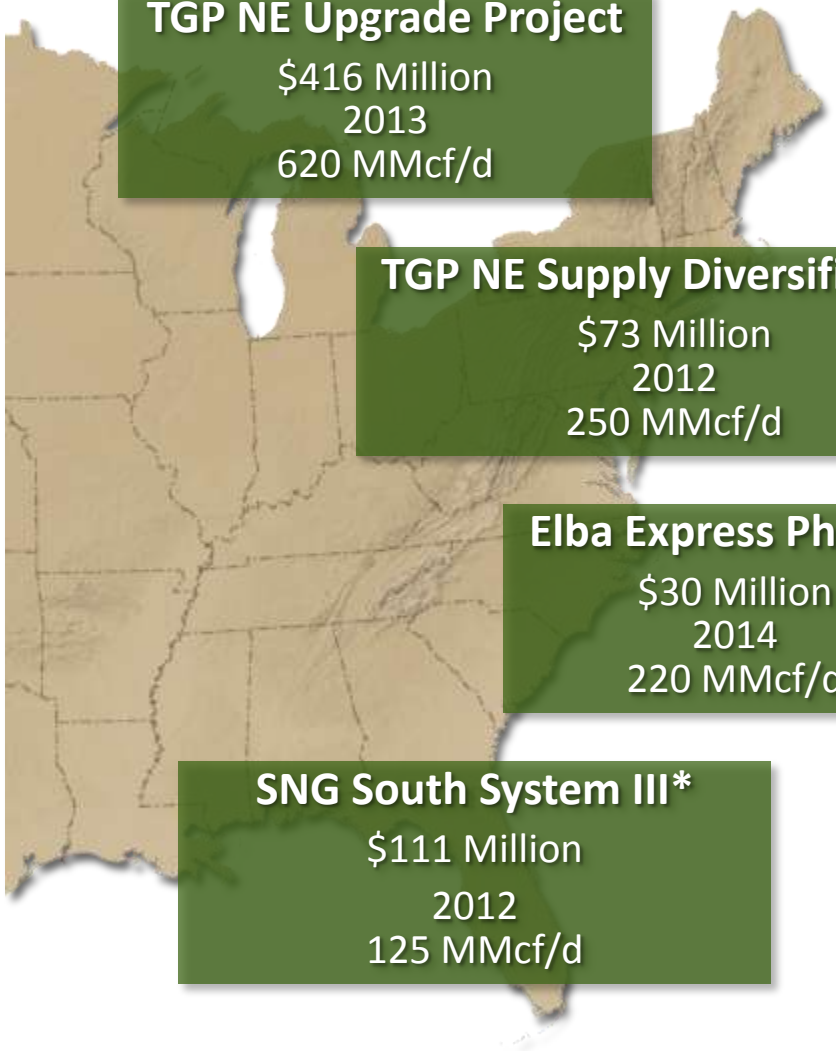
[1]Phase two of three-phase project, includes SESH II

Ruby Outlook

- Construction progressing toward July completion
- Now expect $3.65 billion cost
- Favorable long-term market fundamentals
  - Large Rockies resource base
  - Canadian exports to US declining
- Near-term challenges
  - Especially slower Rockies production growth

Long-term strategic asset

Remaining Backlog



TGP NE Upgrade Project
$416 Million
2013
620 MMcf/d

TGP NE Supply Diversification
$73 Million
2012
250 MMcf/d

Elba Express Phase B
$30 Million
2014
220 MMcf/d

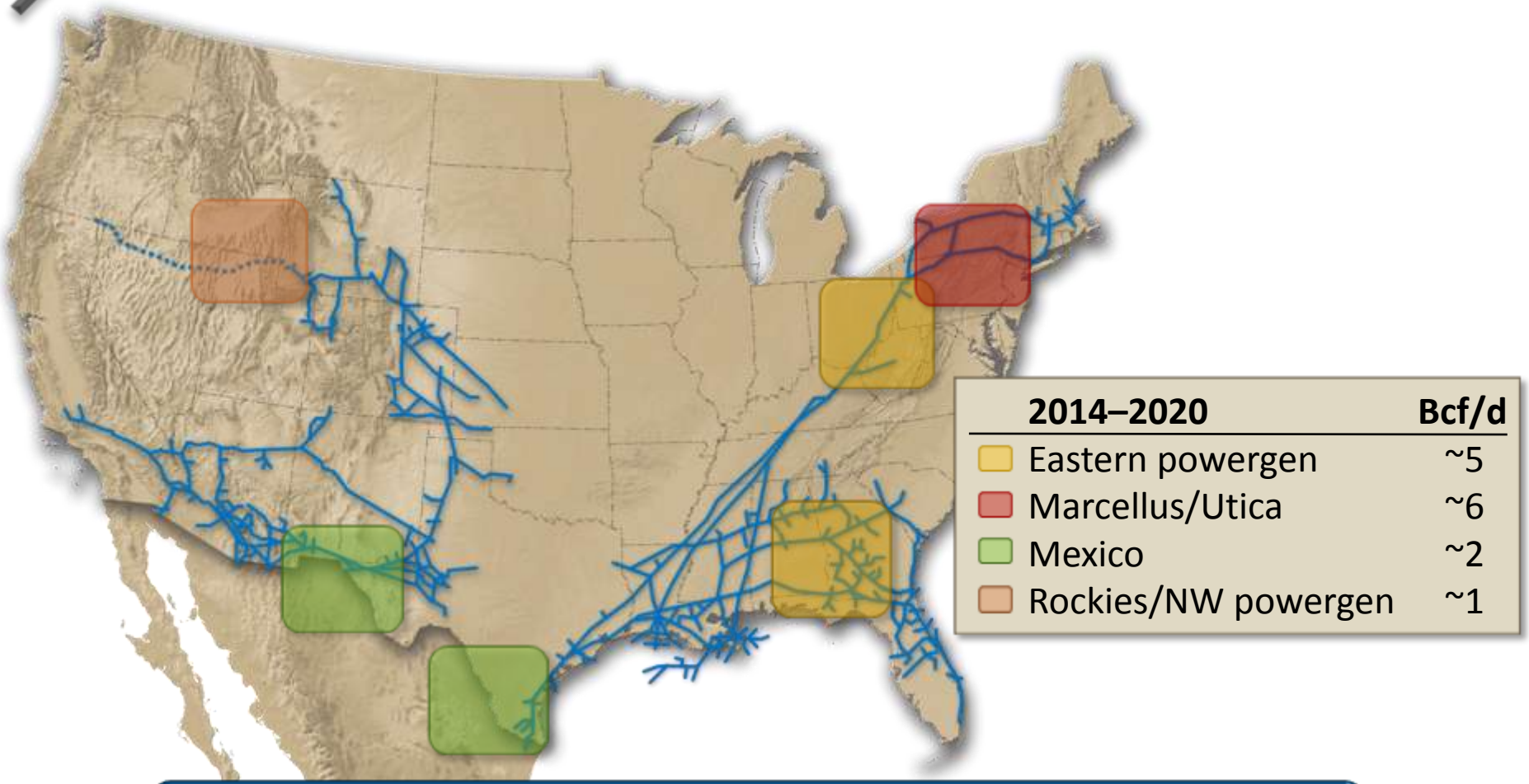
SNG South System III*
$111 Million
2012
125 MMcf/d

ALL PROJECTS FULLY-SUBSCRIBED

Pipelines generate significant cash in 2012

*Phase III of three-phase project which includes SESH Phase II. Phase I placed in-service January '11, Phases II and III in-service in June '11 and June '12, respectively.

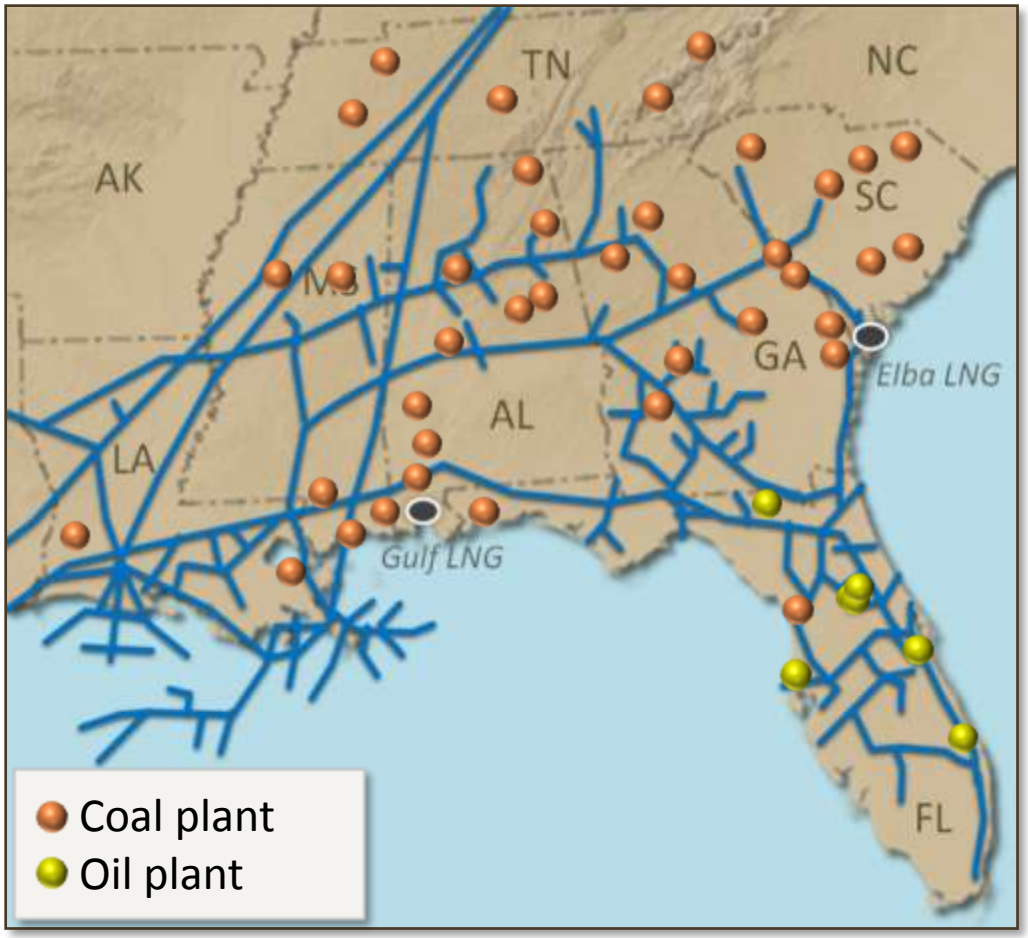
Well Positioned for Continued Future Growth



Estimated $7 billion[1] annual total industry spend
Expect to capture our share

[1] INGAA Foundation, April 2011. Transmission mainline and laterals, compression, storage

Southeast: Powergen Growth and Replacement Opportunities

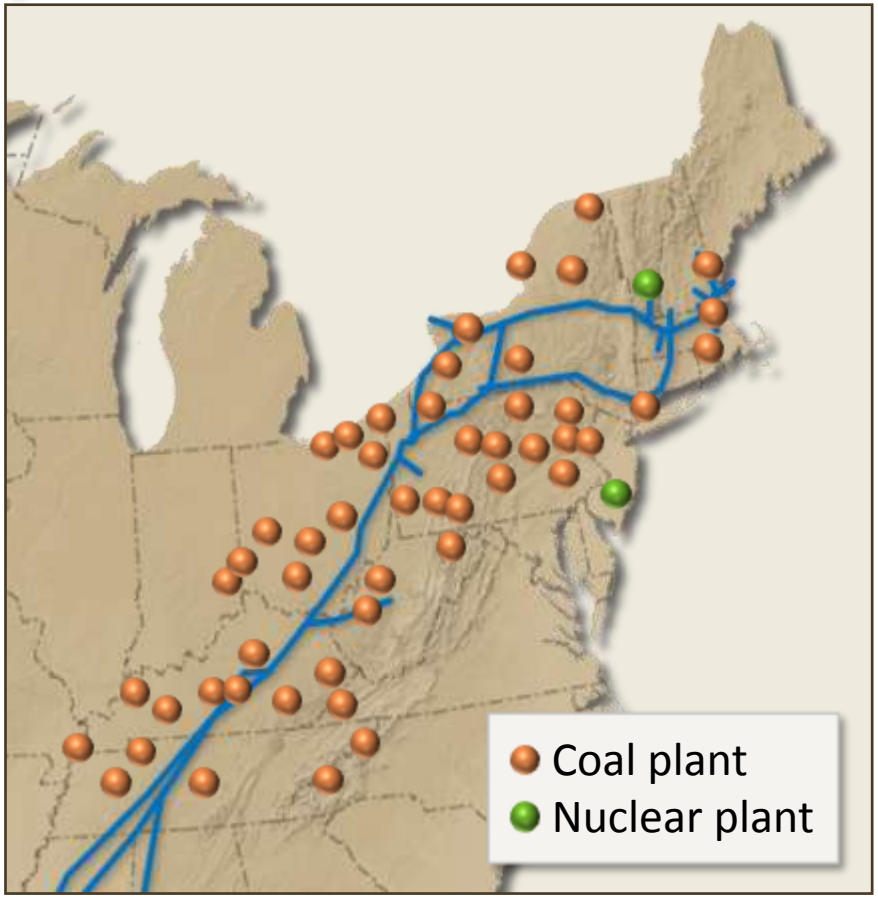


- Expected coal and fuel oil plant closures
  - ~12 GW generation
  - ~2 Bcf/d capacity
- Includes announced closures by Progress, Southern, FPL
- Growing electric market

SNG/FGT have strong positions in growing region

Note: El Paso estimate of potential closures (through 2020)

TGP: Powergen Replacement Opportunities

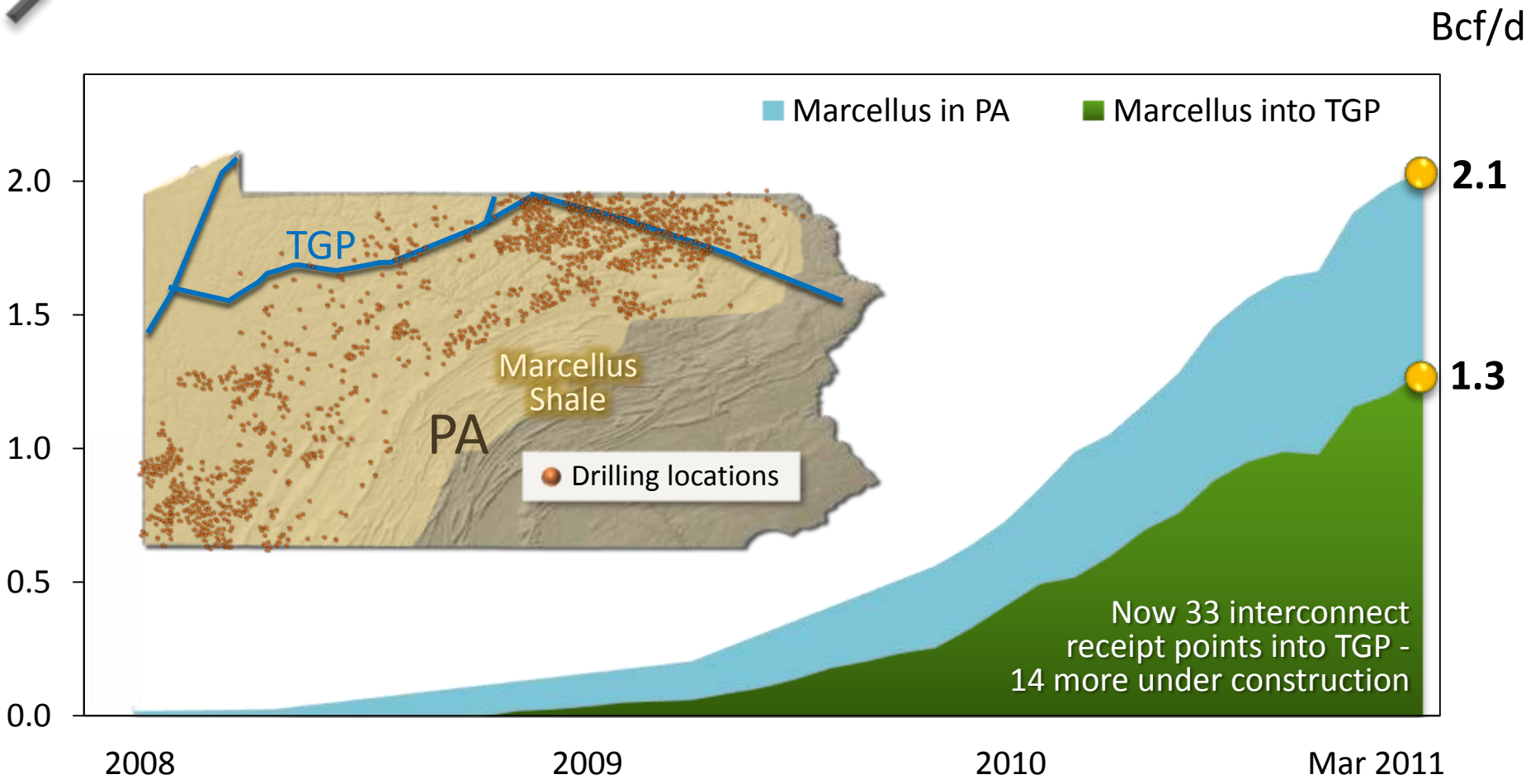


- Expected coal and nuclear plant closures
  - ~18 GW generation
  - ~3 Bcf/d capacity
- Includes announced closures by TVA, AEP, KY Utilities
- TGP has available capacity in TN, KY, OH

TGP well positioned to capture future growth

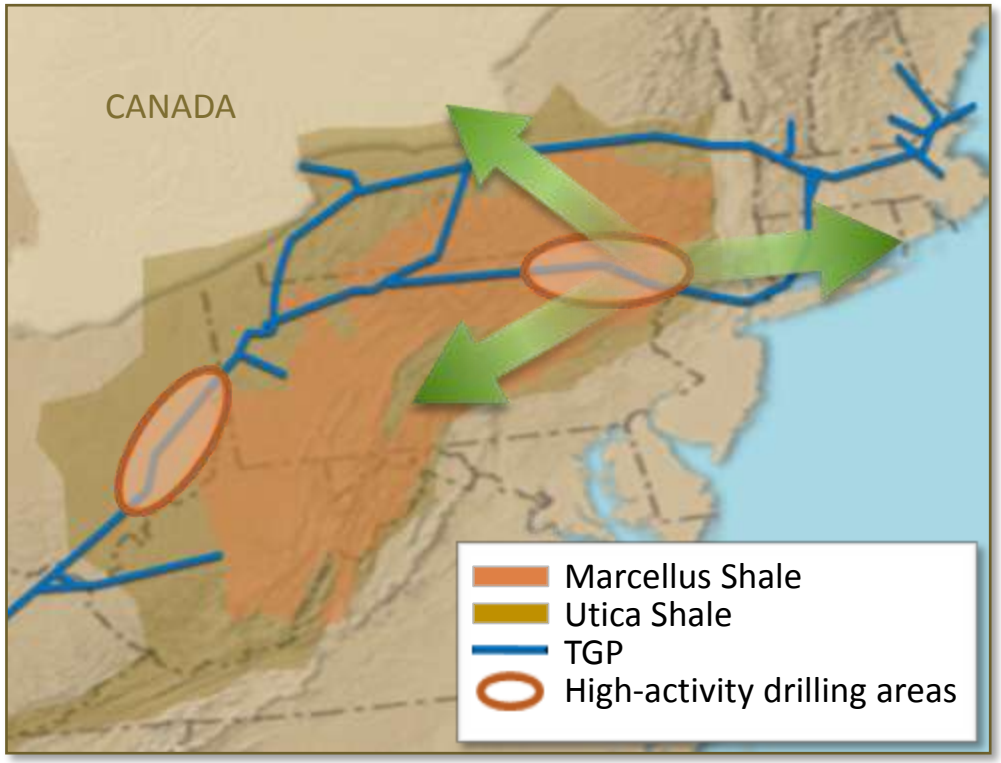
Note: El Paso estimate of potential closures (through 2020)

TGP: Capturing Marcellus Growth



Ideally located in northeast PA

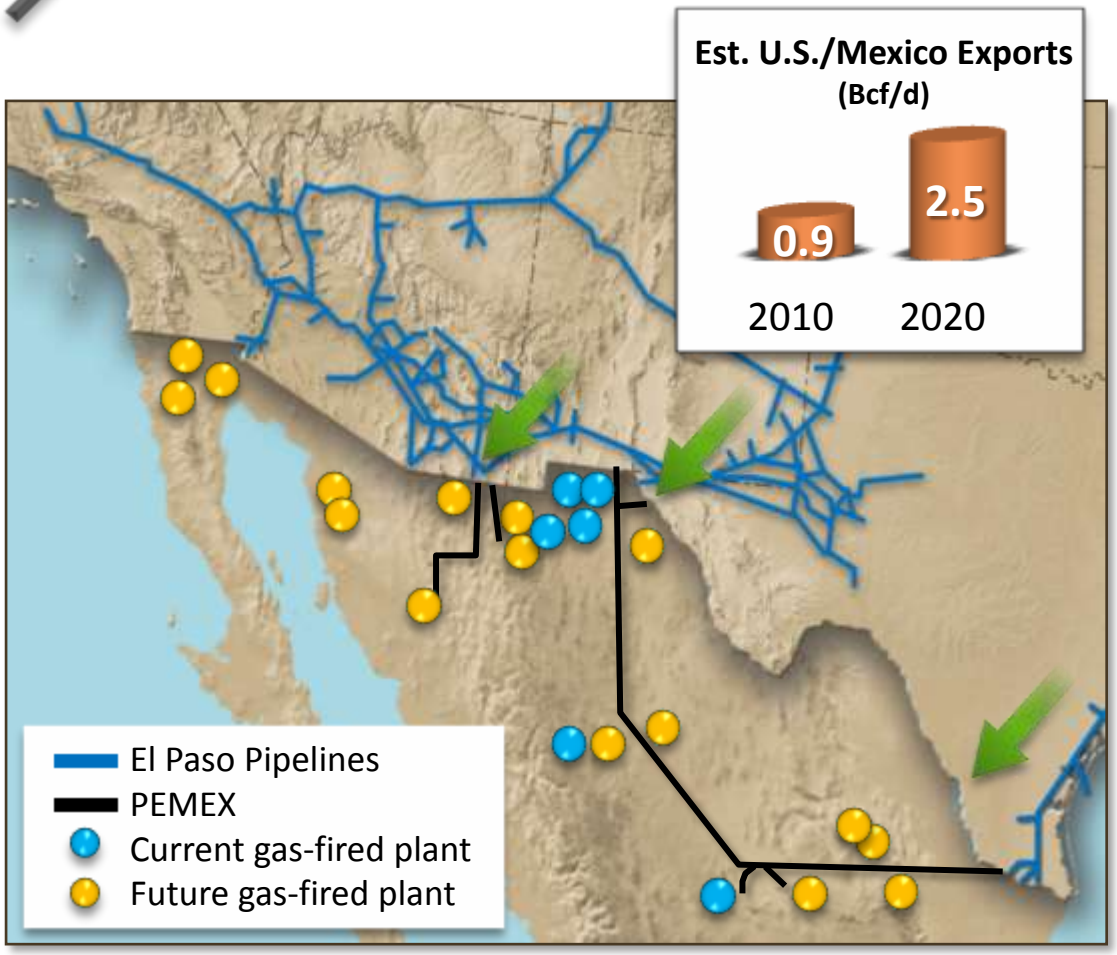
TGP: Northeast Shale Opportunities



- $50 MM–$60 MM revenues from Marcellus backhauls 2012–2013
- Completing >$1 billion of expansions; fully-subscribed
- Area expecting production growth > 6 Bcf/d
- Excellent position in Utica

Success to date; more to come

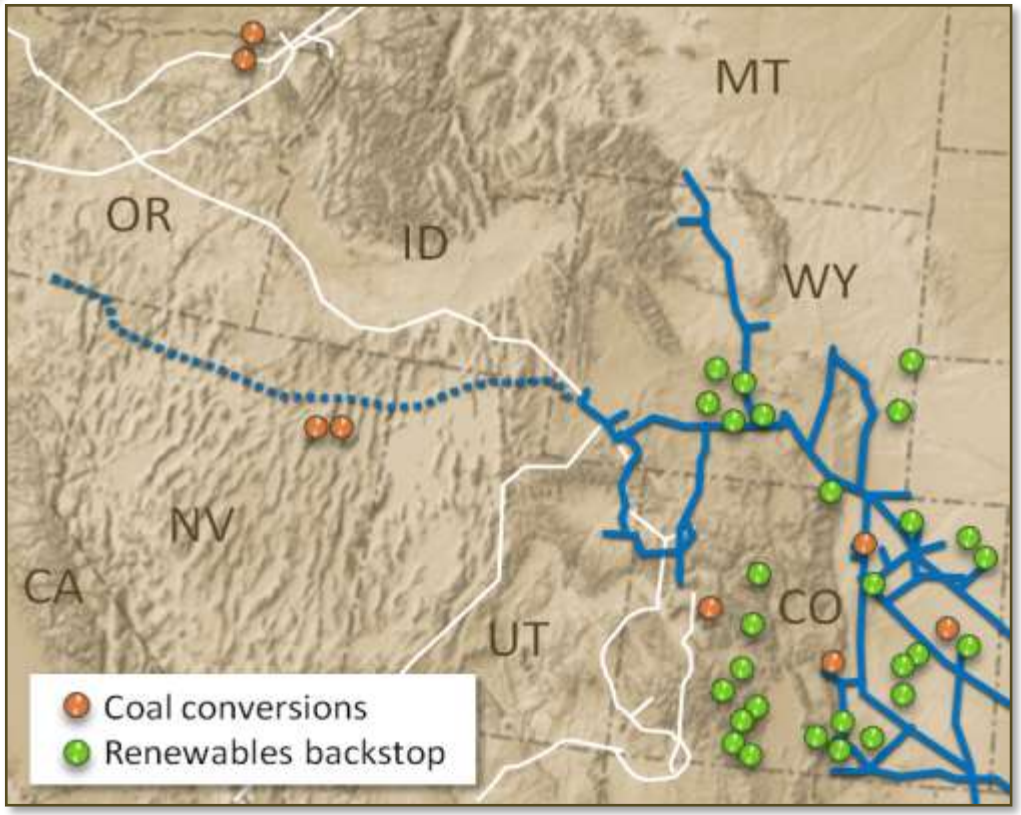
EPNG & TGP:
Export Opportunities to Mexico



- EPNG and TGP provide significant deliveries to Mexico
- Expect power generation and industrial growth
- Additional growth from:
  - Fuel oil conversions
  - PEMEX emphasizing oil over gas
- Recently contracted 185 MMcf/d EPNG expansion

EPNG and TGP set to win

Rockies Front Range/Northwest: Replacement and Renewable Opportunities



- Expected coal closures and renewable generation back-stop
  - ~ 6 GW generation
  - ~ 1 Bcf/d capacity
- Strong environmental mandates in CO, OR, WA

CIG strong market position
Ruby provides new capacity/supply diversity

Note: El Paso estimate of potential closures (through 2020)

Growth Opportunities Summary

2014–2020	Bcf/d	Pipeline Benefitting
Eastern powergen	~5	TGP/SNG/FGT
Marcellus/Utica	~6	TGP
Mexico	~2	EPNG/TGP
Rockies/NW powergen	~1	CIG/Ruby

$7 billion[1] per year in total industry spend
Expect to capture our share

[1] INGAA Foundation, April 2011. Transmission mainline and laterals, compression, storage

Summary

- Unique franchise
  - Scale/scope
  - Positioning
  - Connectivity
  - Execution

- Stable earnings and cash flow
- Significant known growth, cash generation
- Positioned for future growth opportunities

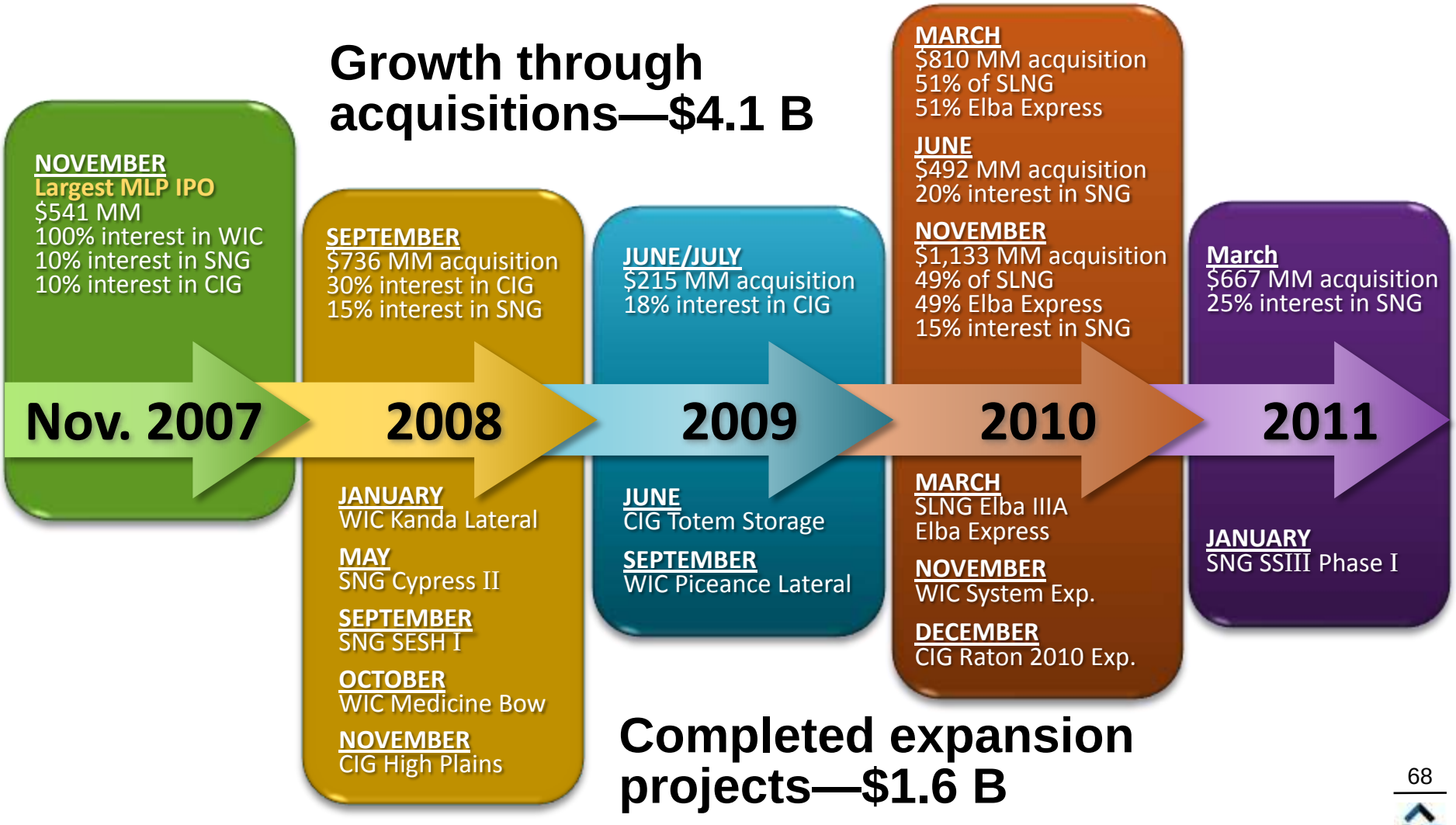
MLP Strategy Review

J. R. Sult
Executive Vice President & Chief Financial Officer

MLP Overview

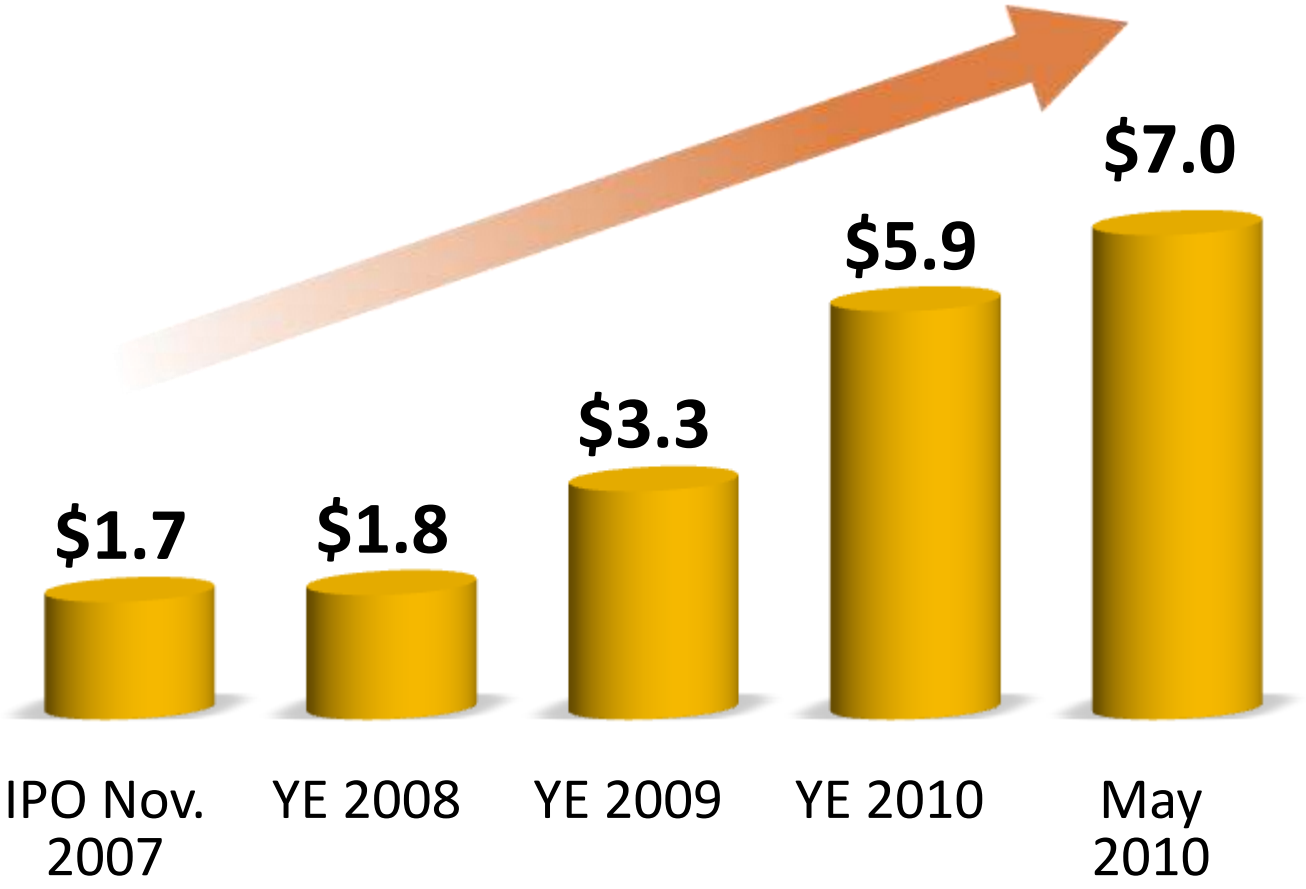
- 2010 was best year yet
  - $2.4 B drop down transactions
  - $1.4 B equity raised (most ever by an MLP)
- Drop down strategy has been win/win for EP shareholders & EPB unit holders
- Continued execution results in rapid growth of GP distributions (via IDR)
- Strong start in 2011

Acquisitions and Organic Projects Have Provided Steady Growth



Now One of the 10 Largest MLPs

Market Cap ($ Billions)



Premium Assets

WIC (100%)

CIG (58%)

SNG (85%)

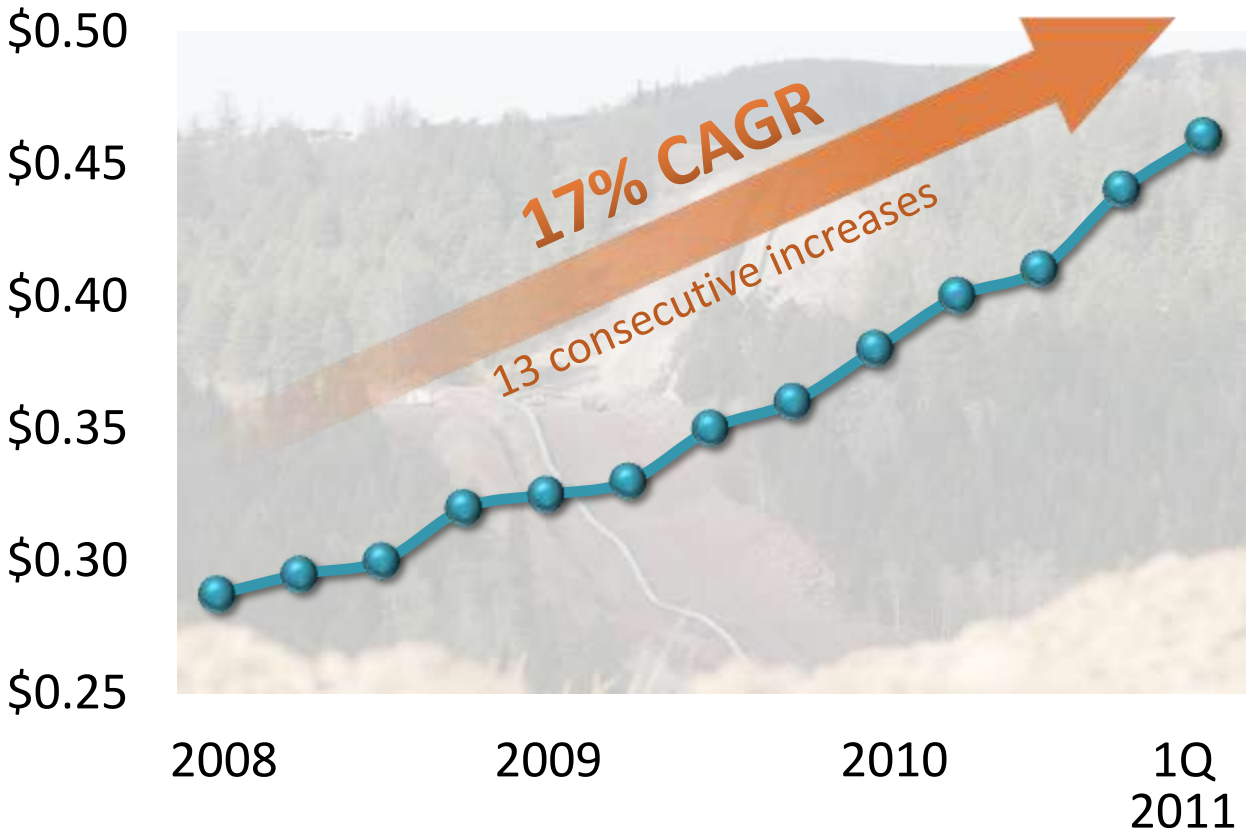
Elba Express (100%)

SLNG (100%)

MLP franchise has expanded
Positions have been cored up

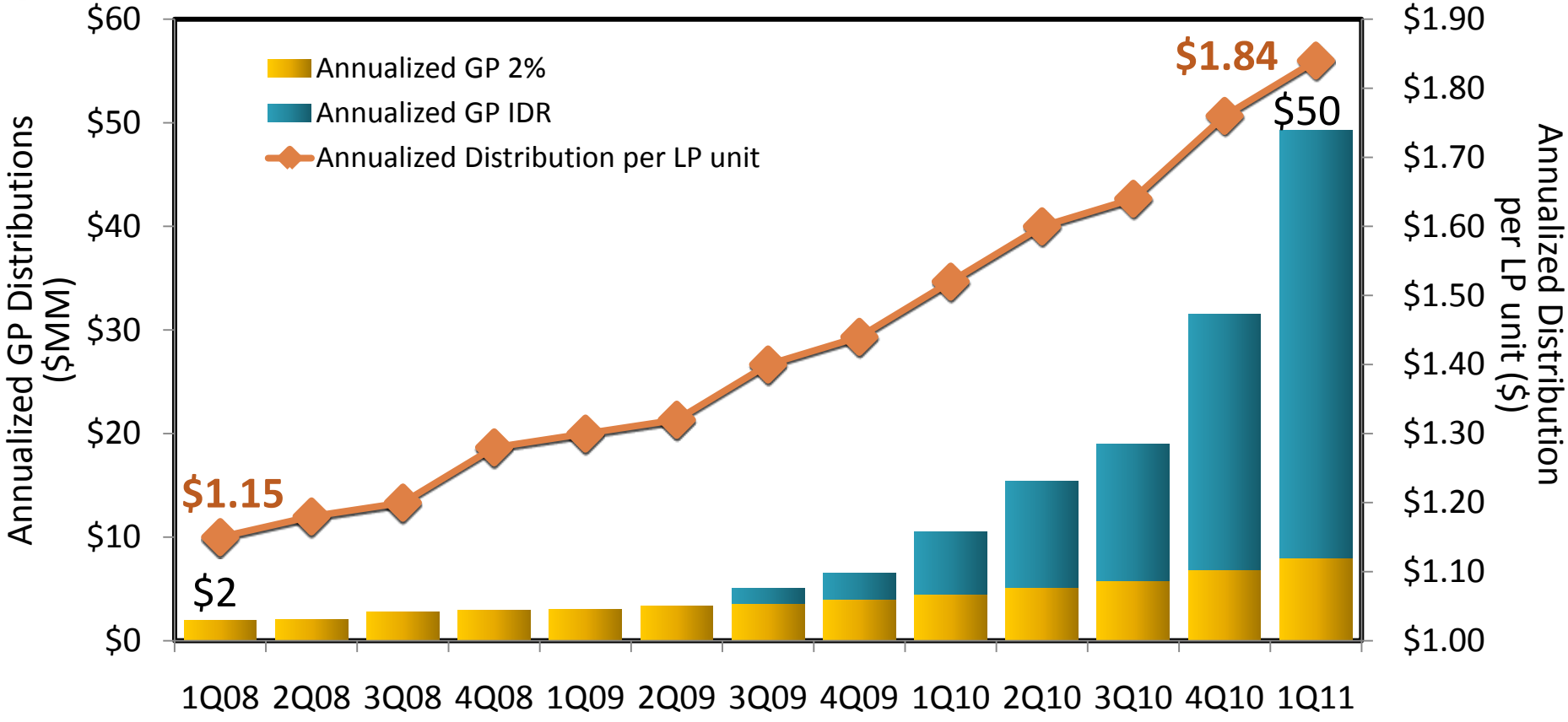
Distribution Growth Mirrors Asset Growth

$/Unit



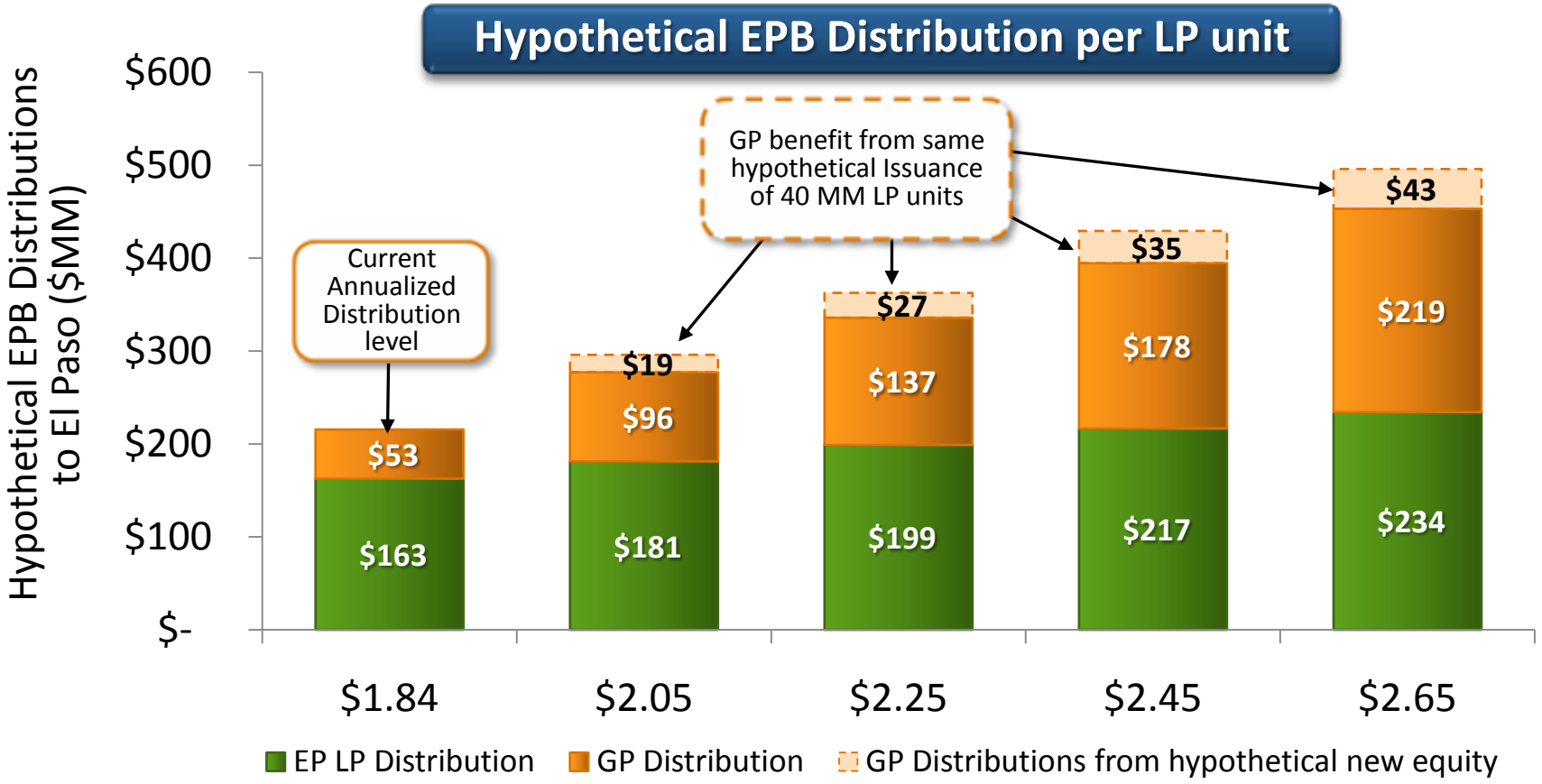
~25% total annual return to unitholders since IPO

GP Distributions Accelerate



GP distribution growth a multiple of EPB distribution growth
On track for $60 MM—$70 MM for 2011

Significant GP Distribution Growth Potential



GP distributions can double with 10% increase from current distribution level[1]

[1]Assumes 10% increase from current annualized per-unit distribution level; includes hypothetical issuance of 40 million new LP units

EPB Off To a Great Start in 2011

- $925 MM equity raised so far
  - More than assumed in all 2011
- Well positioned for second drop down this year
- Demand for best in class MLP continues to be outstanding

Trajectory for continued execution of MLP strategy is excellent

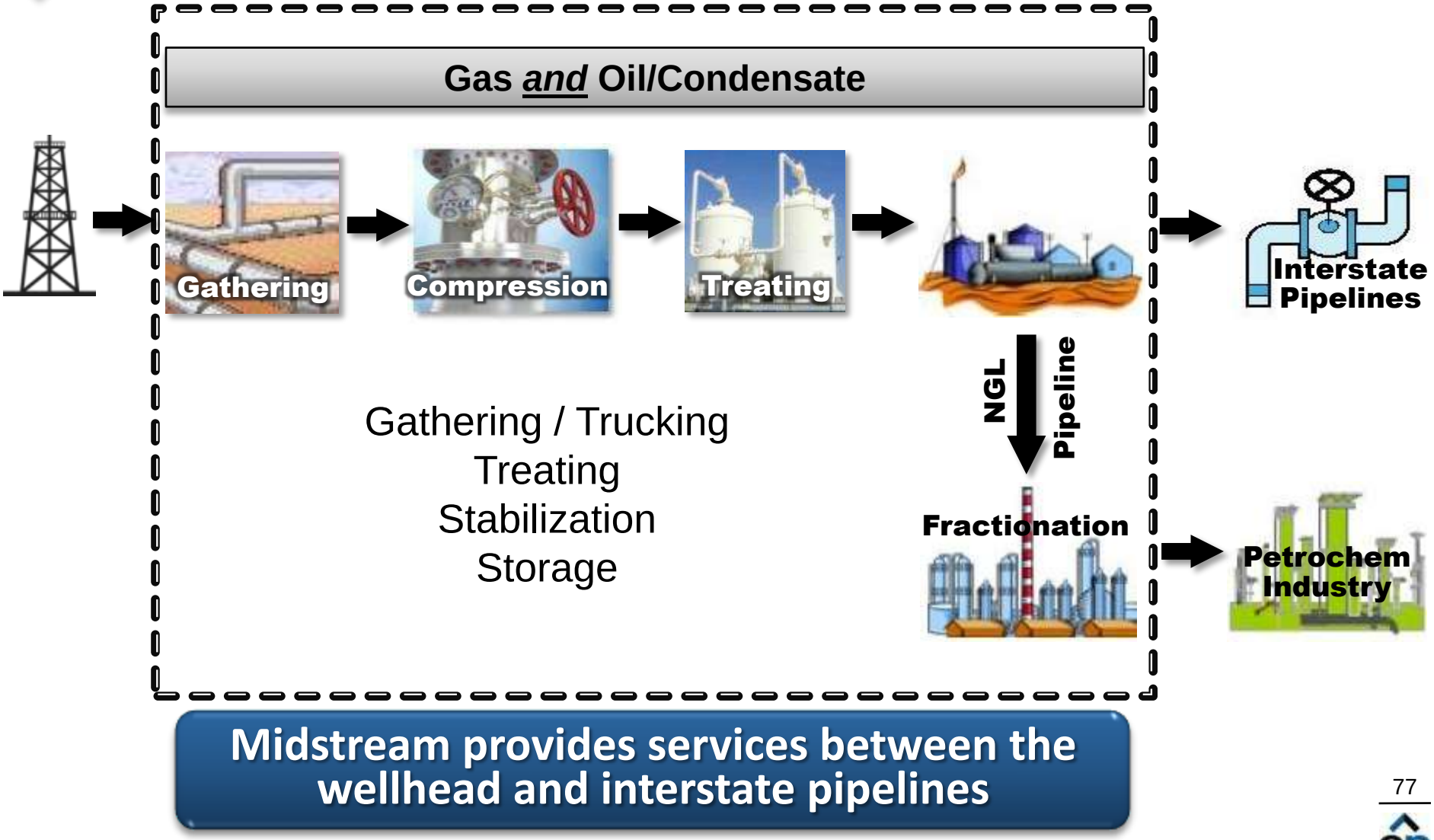
MLP Drop Down Story Keeps Getting Better

- El Paso committed to continue dropdowns
  - Greater valuation in MLP
  - Grow GP distributions (via IDR)
  - Use cash proceeds to continue balance sheet improvement
- Large inventory of suitable assets
  - Only one-third of proportional Pipeline EBITDA in EPB
- ~ $3 billion NOL provides significant flexibility

Midstream Group

Mark Leland
President, Midstream Group

How We Define Midstream

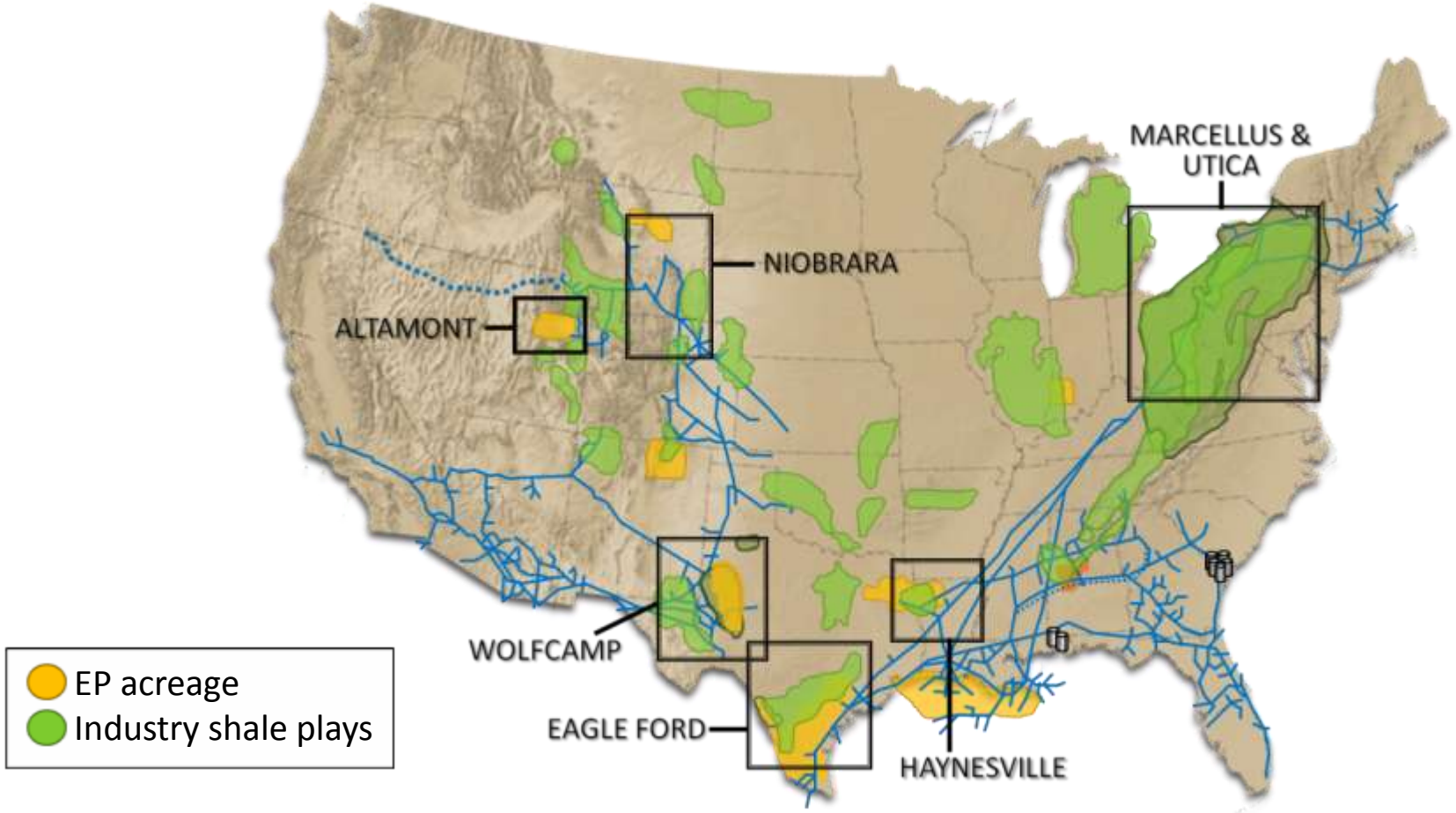


Our Vision For EP Midstream

- ***Substantial Midstream Player*** in key basins where El Paso operates
- An ***Important and Visible Growth Driver*** to El Paso Corporation
- A BU that ***Adds Value*** directly and indirectly to Pipeline and E&P Groups
  - Source of supply for pipelines
  - Optimize underutilized pipe capacity
  - Ensure infrastructure available for E&P
- Execution and results driven—***Customer Oriented***
- A BU where ***EP Employees*** want to come to work and where EP BU's want to recruit

78

Focus Areas Driven by Asset Synergies



$30 B of gathering and processing infrastructure to be added in North America by 2020[1]

[1]Estimates from INGAA's North American Infrastructure Study

Midstream Investment Partnership

- El Paso owns 50% of El Paso Midstream Investment Company (EPMIC)
- EPMIC owns 100% of Altamont assets
- Partner has committed $500 MM over 4 years
- Capital efficient vehicle to develop Midstream business

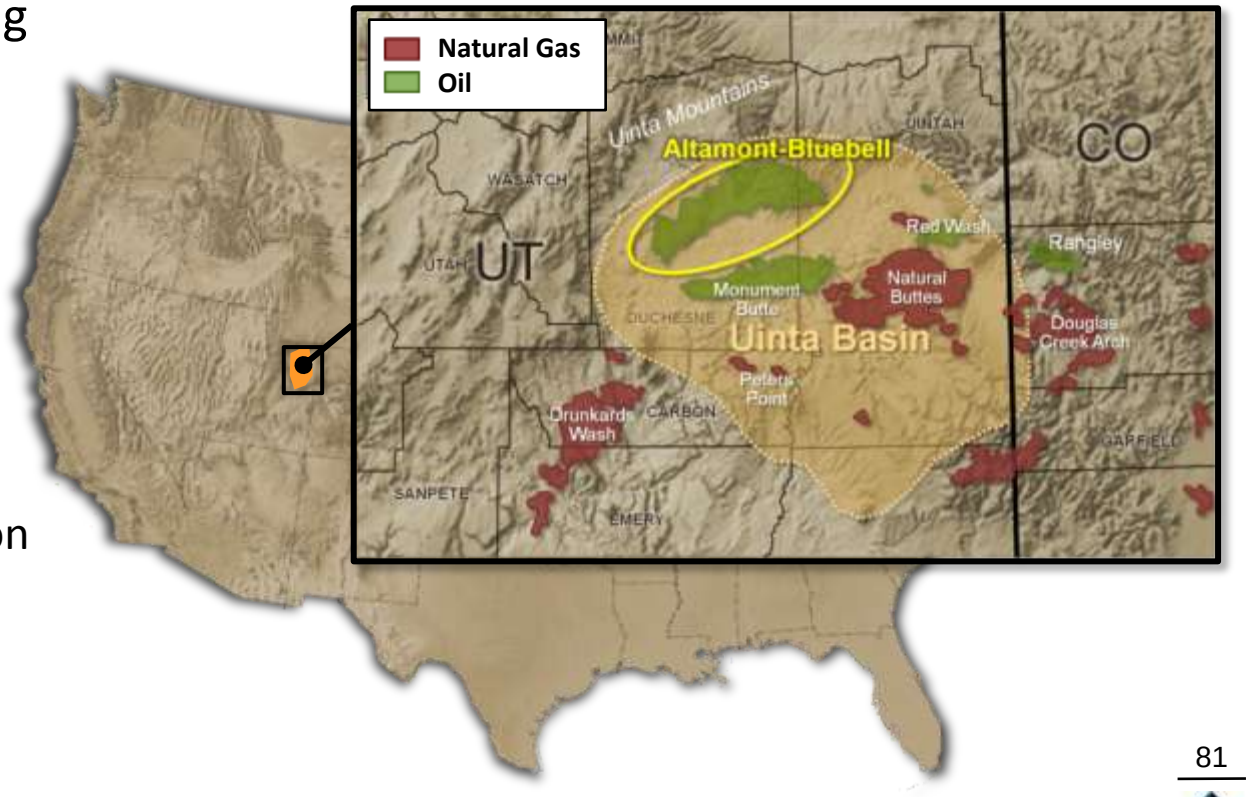
Midstream opportunities executed in partnership

Altamont—Area Overview

- Conventional oil play
- Drilling activity and oil production are increasing
- Gathering and processing infrastructure easily expandable
- Midstream services include:
  - Gathering and compression
  - Treating
  - Processing
  - Third-party fractionation
  - NGL marketing

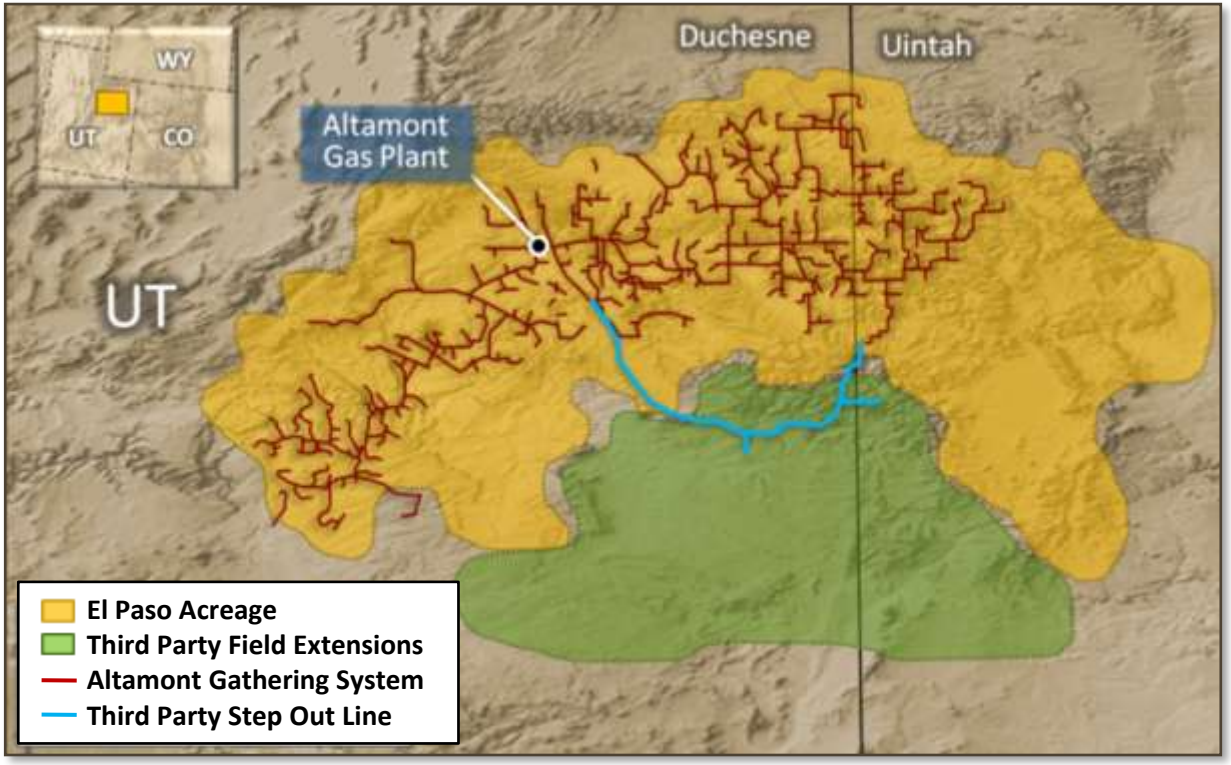
- **Key Producers:**

  EP / BBG / DVN / Ute Energy / NFX / BRY

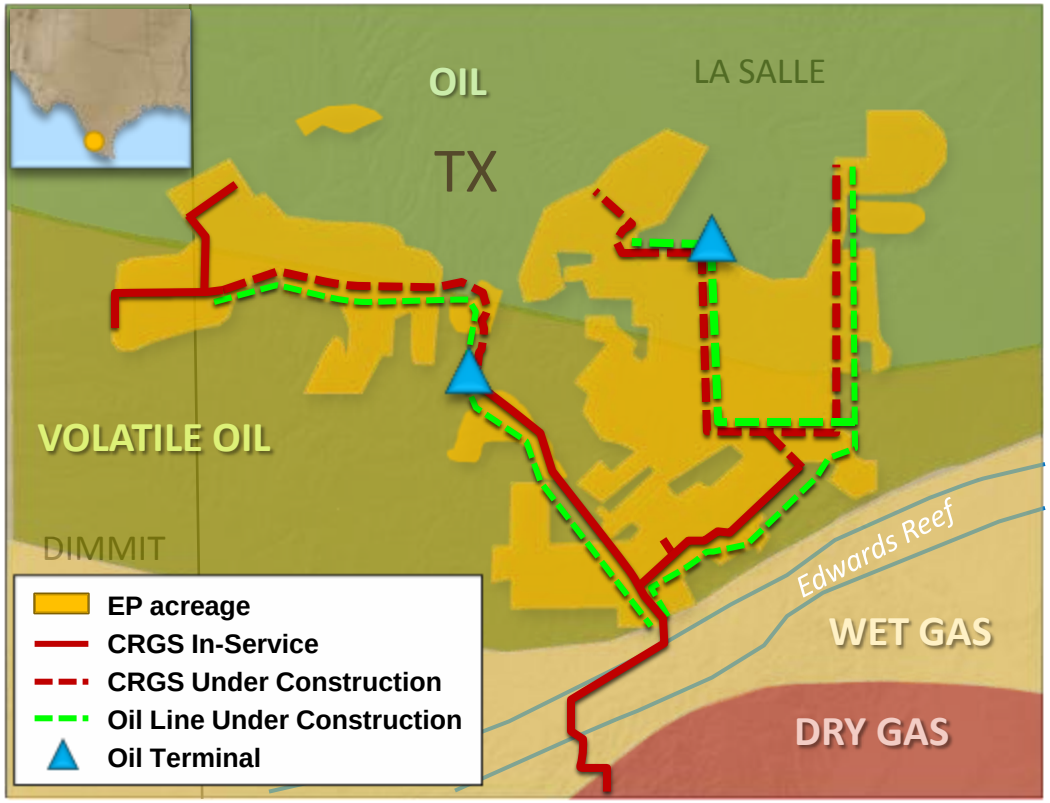


Altamont Plant Expansion and Step-Outs

- 1,002 pipeline miles
- 402 producing wells
- 23,000 hp compression
- 40 MMcf/d plant capacity
- Altamont debottleneck project (50% capacity increase)
- Third-party gathering expansion
  - 25-mile low-pressure gathering header for new third-party volumes
  - Increases dedicated acreage by ~115,000 acres (54% increase)
  - $25 MM expansion capex (100% basis)



Camino Real Gathering System (CRGS)



GAS GATHERING SYSTEM

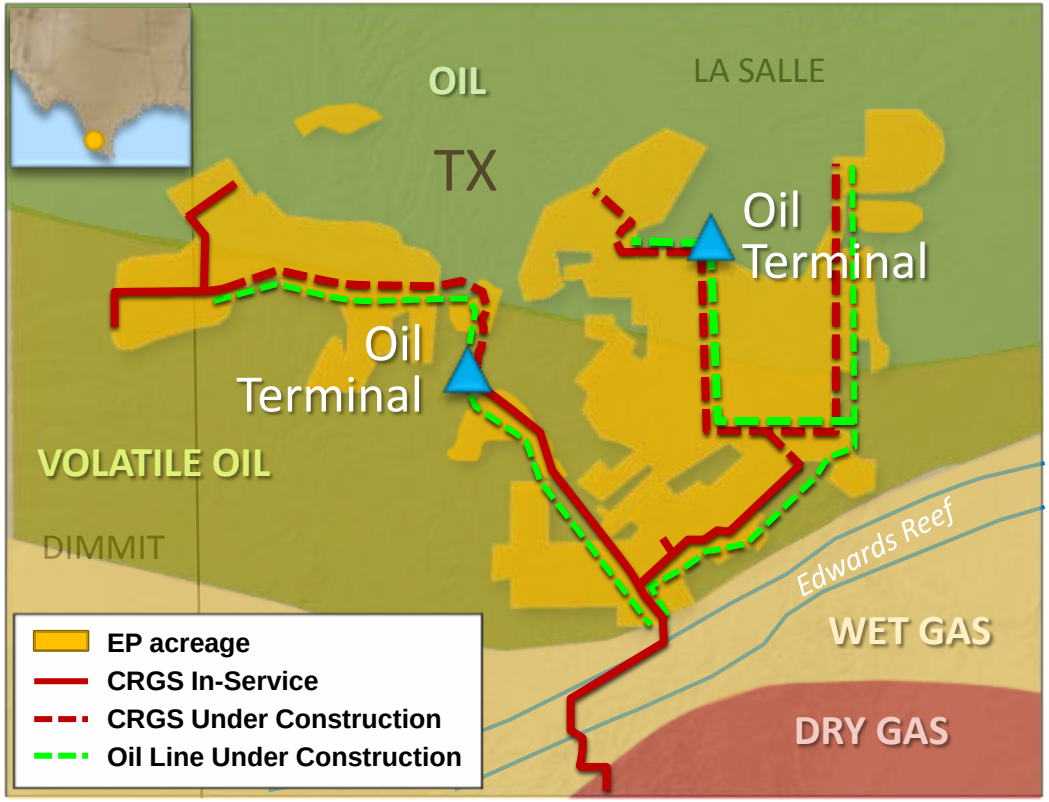
- 70 miles of 6" to 12" diameter pipe
- Capacity of 150–170 MMcf/d
- ~ $50 MM total capex
- E&P plus third-party shippers

OIL GATHERING SYSTEM

- 68 miles 6" to 12" diameter pipeline
- 80,000 Bbls/d capacity
- ~$50 MM total capex

Fully operational gas system mid-summer; oil system early-fall

CRGS Oil & Gas Export Options



EXPECTED GAS INTERCONNECTS FOR PROCESSING AND TAKE-AWAY

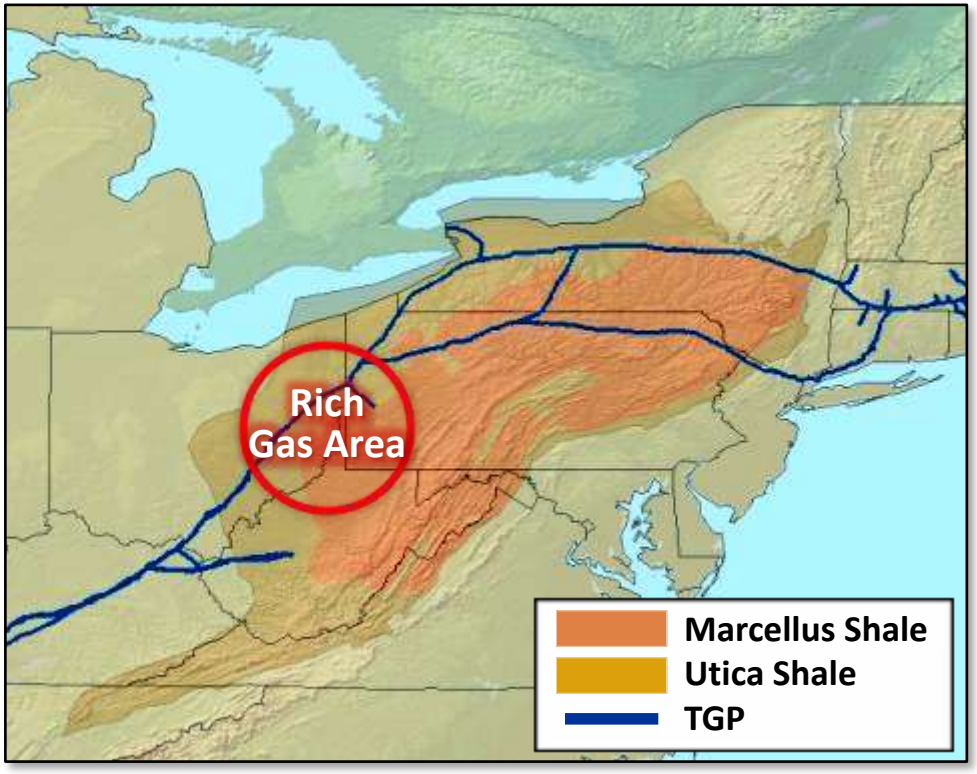
- Regency
- Enterprise
- Energy Transfer
- Kinder-Copano

OIL TAKE-AWAY

- Immediate on-lease trucking
- Central terminal trucking
- Pipeline take-away

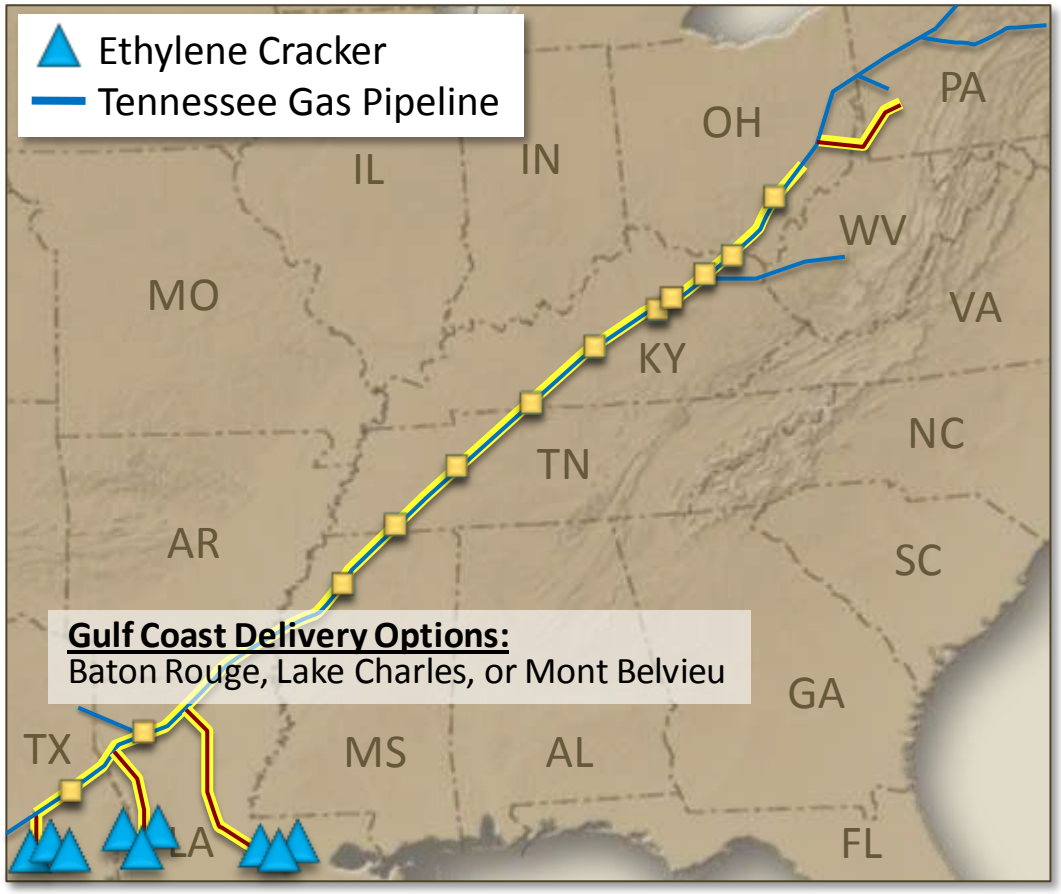
E&P and third-parties to enjoy multiple gas and oil export options

NE Shale Overview



- EPM concentrating on rich gas and oil windows of Marcellus and Utica shales
- >100 Tcf expected ultimate recovery in southwest PA alone
- Capturing value of NGLs can increase returns by upwards of 30%
  - Marcellus wet gas continues ~4–5 gallons of ethane per Mcf of gas; approx 16% of the wet gas stream
  - Utica shale expected oil with associated gas
- TGP has available capacity

El Paso Response: Marcellus Ethane Pipeline System (MEPS)



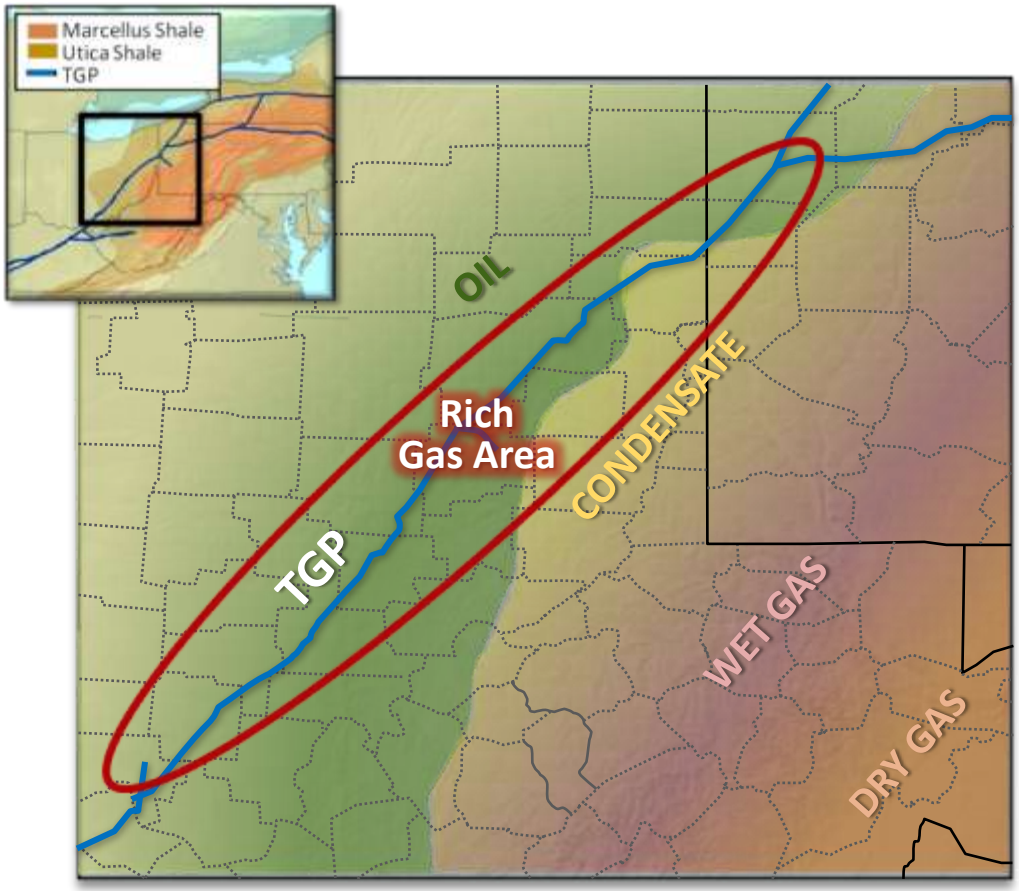
PROJECT SCOPE

- MEPS will:
  - Collect purity ethane in S.W. Marcellus
  - Redeliver to the Gulf Coast
- Initial capacity—60,000 to 80,000 BPD; expandable to 100,000 BPD
- Best pipeline option to premium gulf-coast markets
- ~ $1 billion total capex

STATUS

- Active discussions with Producers and Petrochemical Companies

Utica Shale Midstream Opportunity

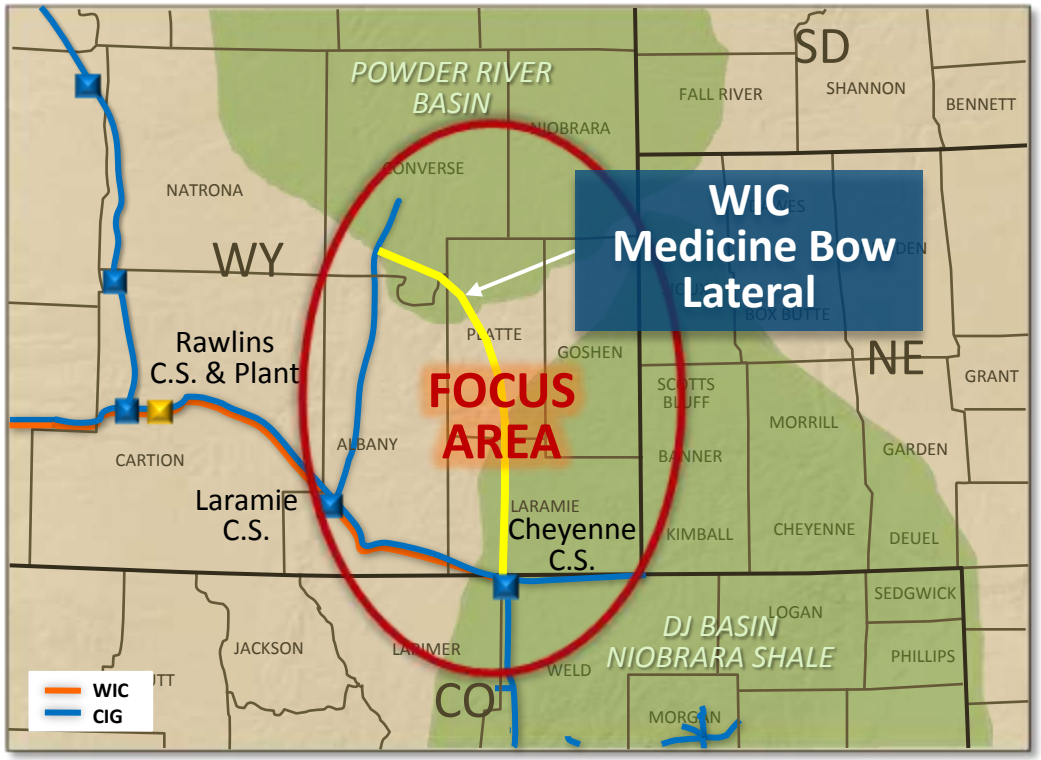


- Utica Shale
  - Underlies Marcellus Shale
  - Most drilling currently in eastern Ohio
  - Expected to be oil/condensate with rich associated gas
- TGP is situated primarily in the oily and rich gas sections of the play
- El Paso has relationships with key producers
- Opportunity to provide rich-gas gathering header, in-field gathering and processing, fractionation including ethane solution via MEPS

Play in early development lacks midstream infrastructure

Niobrara Shale Midstream Opportunity

- Oil play with associated rich gas
- WIC Medicine Bow lateral is situated in the Wyoming region of the play
- EP has strong relationship with major acreage holders in Wyoming Niobrara
- Opportunity to provide rich-gas gathering header (WIC), in-field gathering and processing
- Available WIC capacity



Play in early development lacks midstream infrastructure

Midstream Summary

- MEPS well positioned to provide Gulf Coast ethane supply
- Camino Real Gathering System provides Eagle Ford shale Midstream platform
  - Evaluating option to participate in larger Eagle Ford Rich Gas pipeline and processing project
- Competing for major projects in Utica and Niobrara
- Continue to advance Altamont infrastructure
- JV provides financially efficient platform

Midstream poised to participate in $30 B gathering and processing 10-year build out

Exploration & Production

Brent Smolik
President, Exploration & Production

E&P Creating Significant Value

- Strategy is consistent and fully operational
- Executing well in all phases of our business
- Inventory is bigger, lower risk, oilier and more profitable
- Supportive organizational culture and structure is in place
- Delivering value and sustainable growth

Performance among industry's best

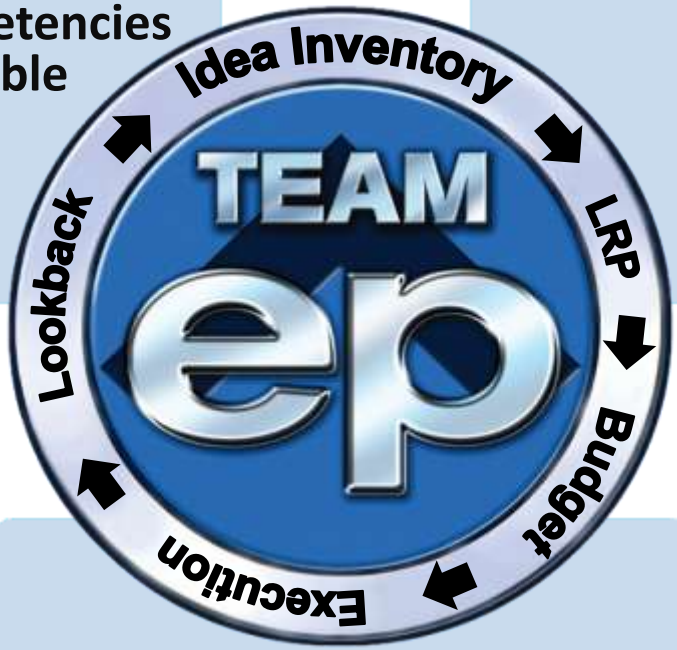
Successful Execution Requires Getting All Three Right

- E&P strategy
- Asset portfolio
- Organizational capability

EXECUTION!

E&P Strategy

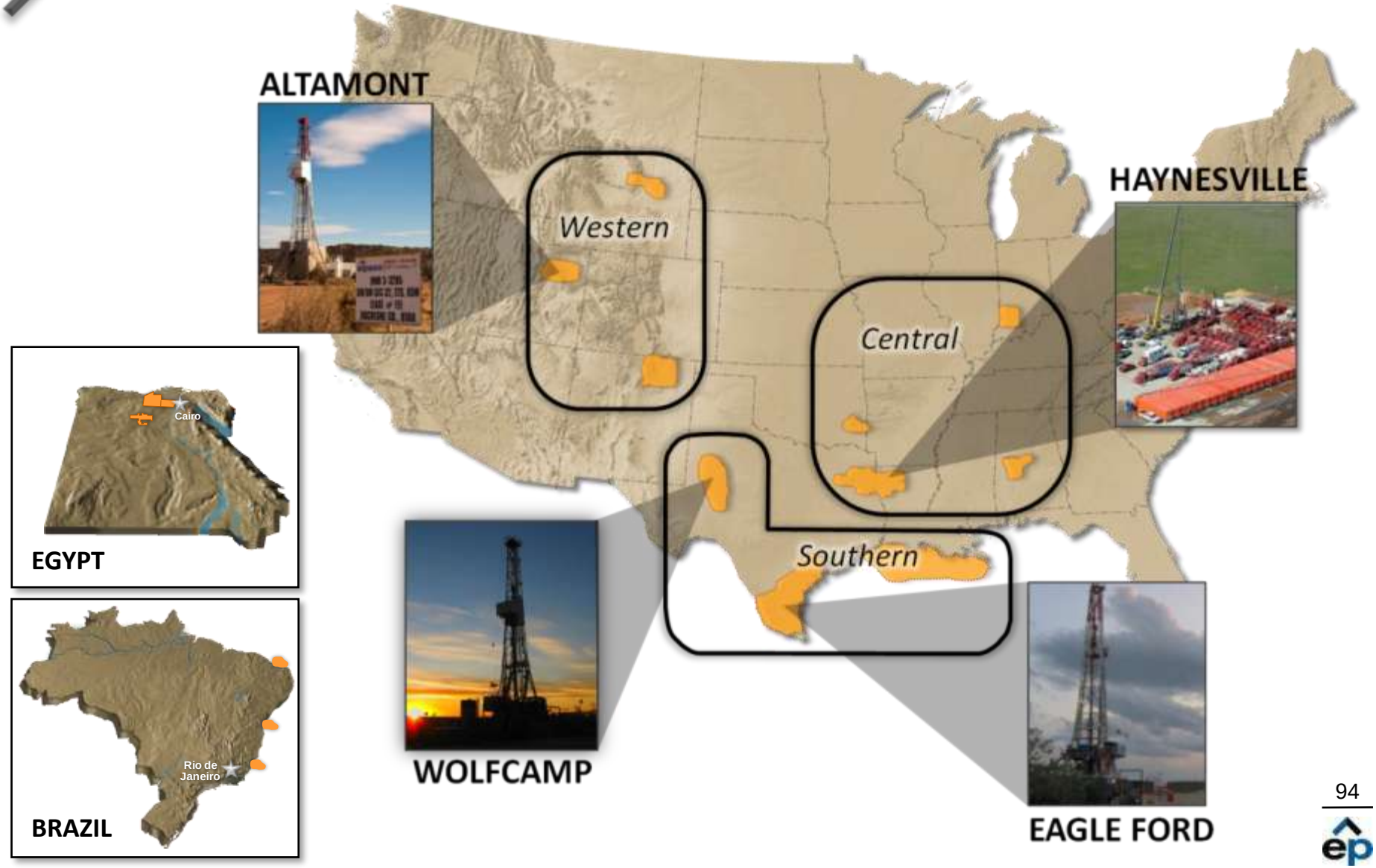
Build and apply **competencies** in assets with **repeatable programs** and **significant project inventory**



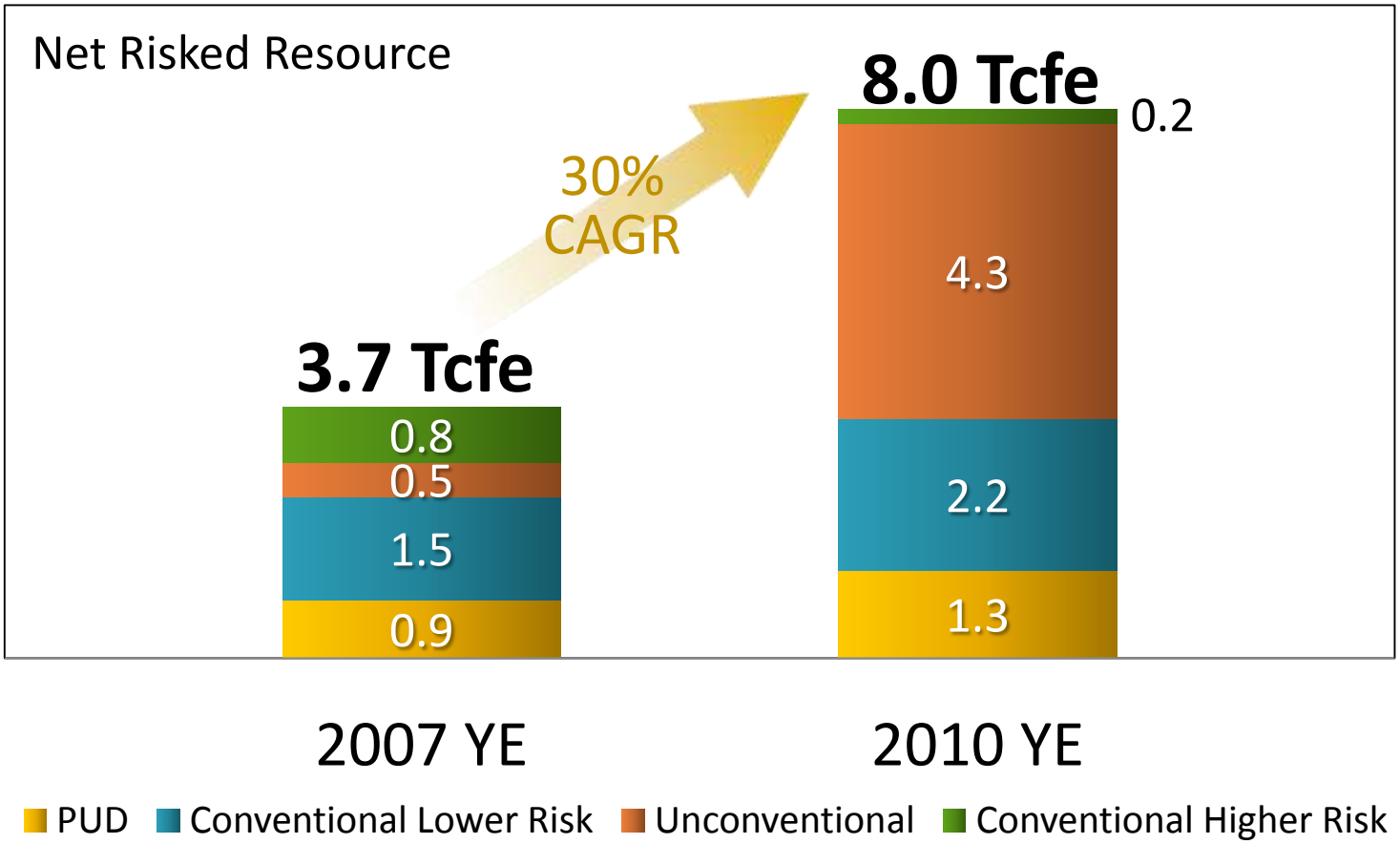
Add assets with inventory that fit our competencies and **divest assets** that do not

Sharpen **execution skills** to improve capital and expense efficiency and maximize returns

El Paso E&P Asset Overview



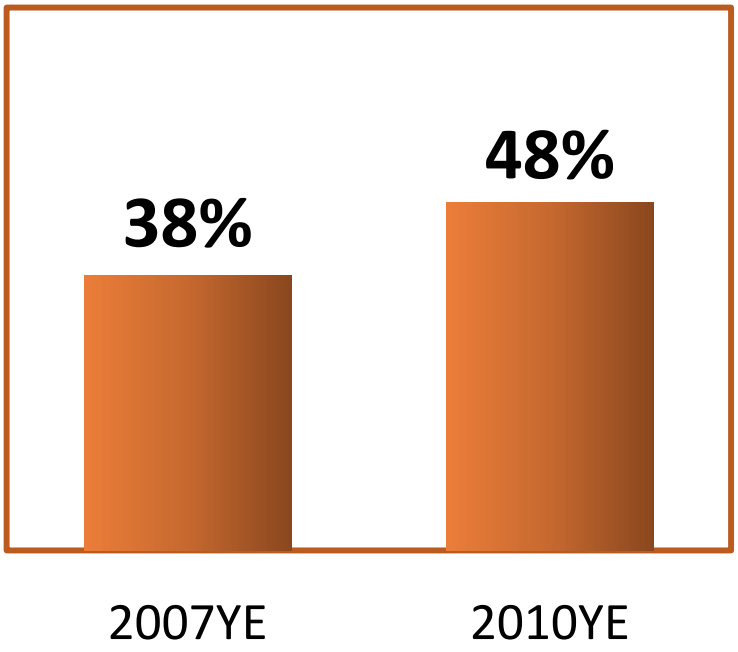
Inventory Has Grown & Improved



Haynesville, Eagle Ford & Wolfcamp have driven significant growth

Inventory Has Become Much More Oily

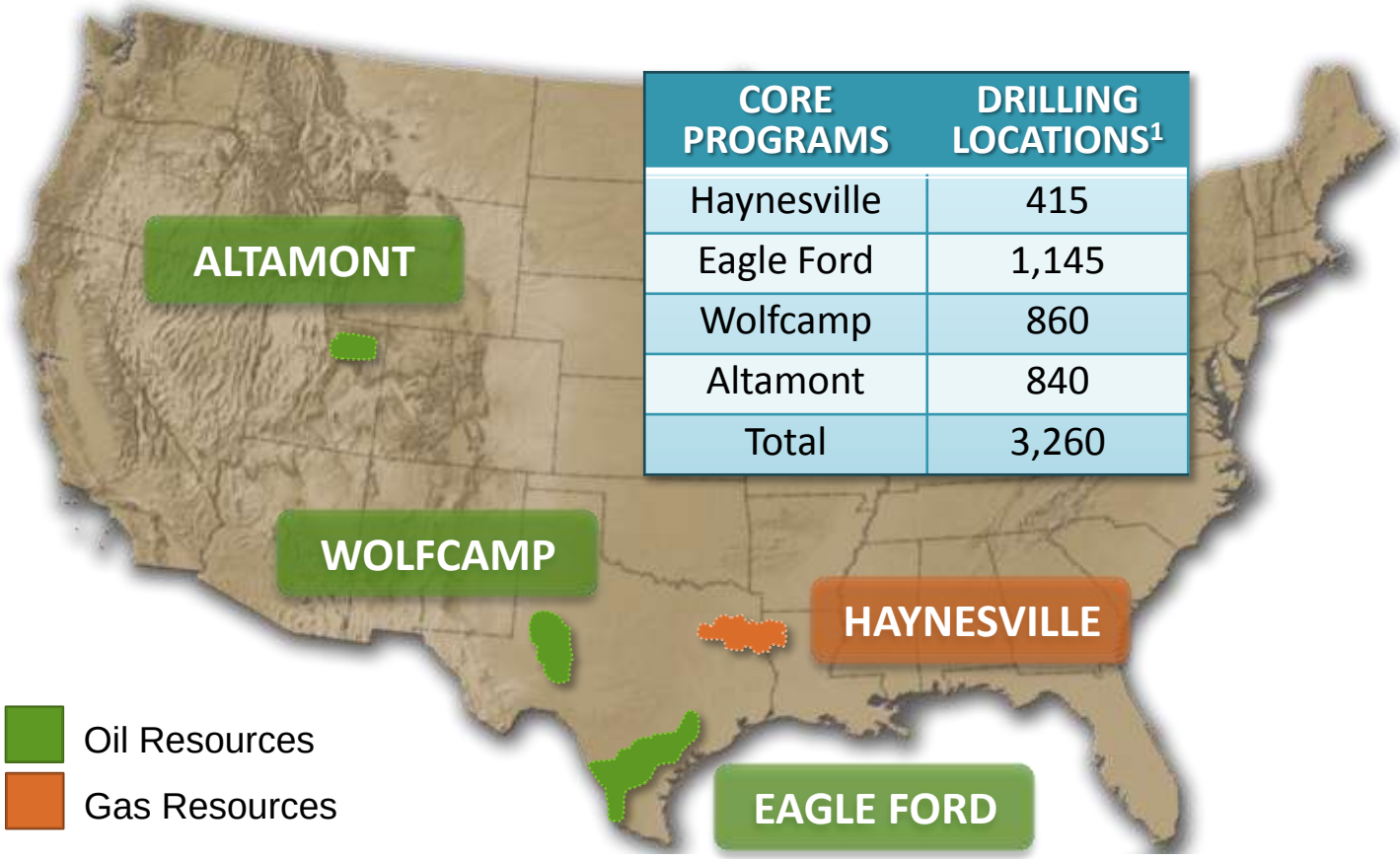
PRODUCT MIX AT 6:1



Oil is >2/3 of future value

Eagle Ford & Wolfcamp have been impactful

Core Programs Provide Multi-Year Drilling Opportunity

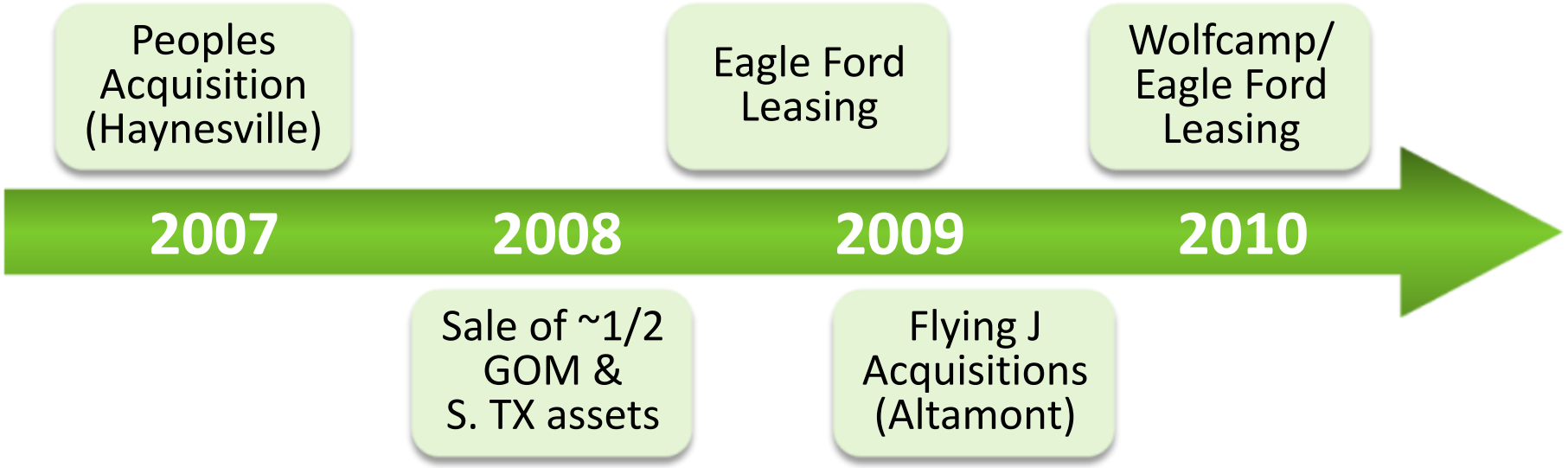


CORE PROGRAMS	DRILLING LOCATIONS[1]
Haynesville	415
Eagle Ford	1,145
Wolfcamp	860
Altamont	840
Total	3,260

>10 years of drilling locations

[1]As of 12/31/10 (includes PUD locations and is shown on an unrisked basis

Portfolio Shifts Aligned with Strategy



- High-grading will continue
  - Sales and additions/oil vs natural gas
- Continued evaluation of new opportunities
- New additions must compete with current inventory

Organizational Capability Improvement - Asset Teams

STRUCTURE

- Organized geographically and by program
- Inventory creation and capital management focused
- Driven by returns and growth in value

ALIGNMENT

- Establish consistent internal performance targets
- Standardize practices/simplify processes
- Pursue break thru opportunities

LEARNING

- Share knowledge across company (technical networks)
- Rigorous post mortem processes
- Shape portfolio through targeted A&D

Organizational Capability Improvement - Operations Teams

STRUCTURE

- Single operations organization
- Capital execution and production optimization focused
- Driven by safety, efficiency, and cost control

ALIGNMENT

- Establish consistent internal performance targets
- Standardize practices/simplify processes
- Pursue break thru opportunities

LEARNING

- Share knowledge across company (technical networks)
- Benchmark competitors
- Build effective partnership (suppliers, operators)

2010 Operating Statistics

DRILLING OPERATIONS

Gross Wells Drilled (No.)	154
Footage Drilled (MM ft)	1.6
Rig Count (average)	13

COMPLETION OPERATIONS

Gross Wells Completed	142
Stages Completed	1,178
Vol. Pumped (MM bbl)	7.0
Sand Pumped (MM lbs)	317

PRODUCTION OPERATIONS

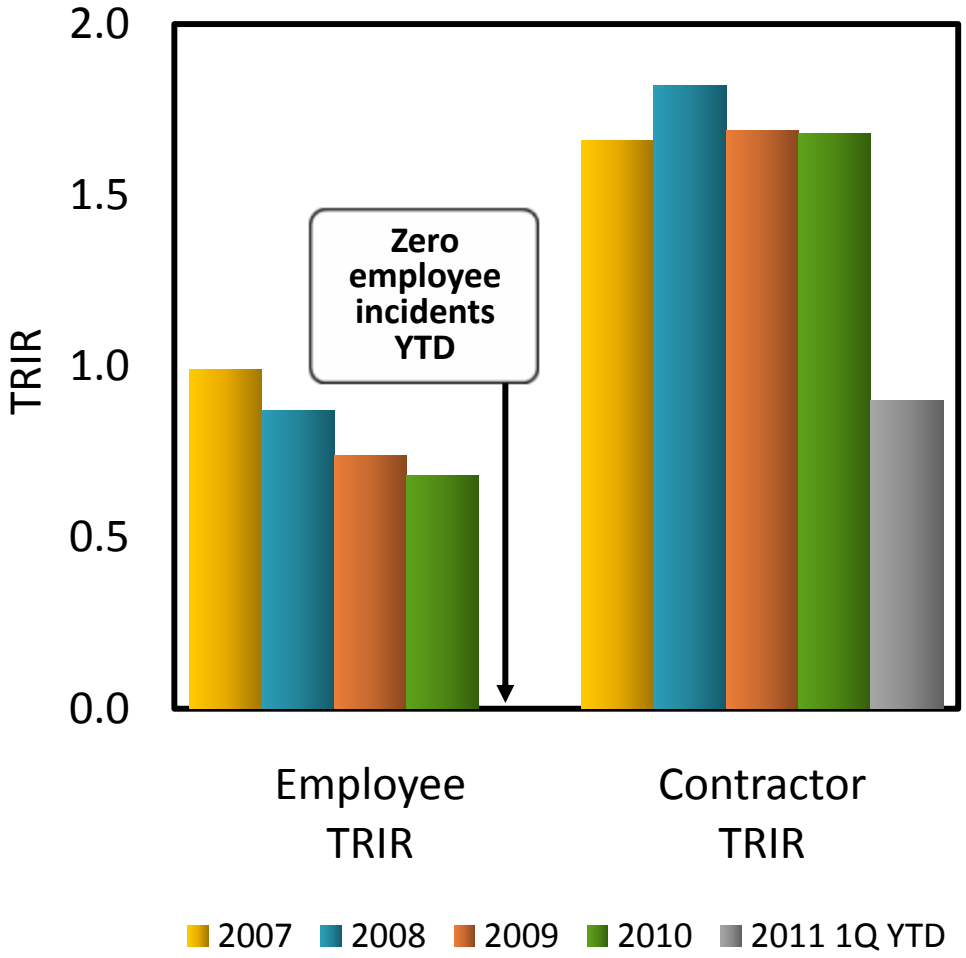
Gross Wells[1]	5,664
Net operated production (MMcfe/d)	629

Note: El Paso operated assets only

[1] As of December 31, 2010

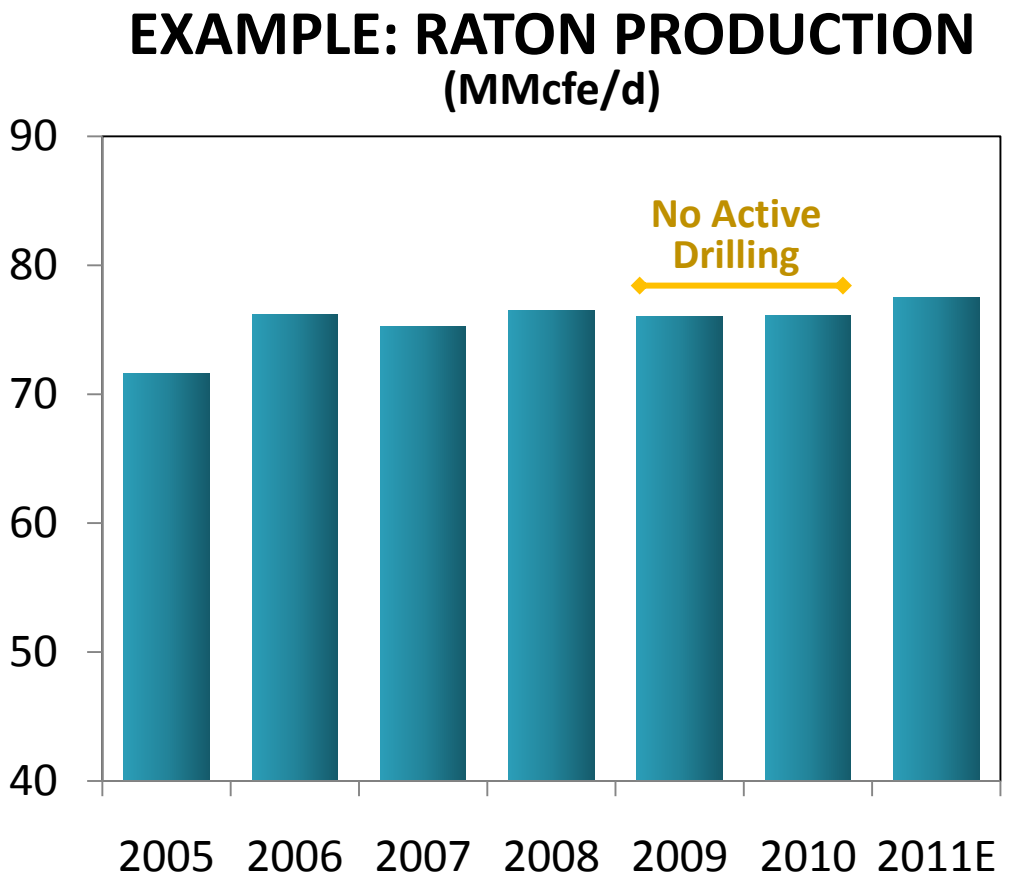
Improving Safety Performance

- Committed to responsible operations
- Improved engagement with contractors and service providers
- Enhanced programs to improve integrity and reliability

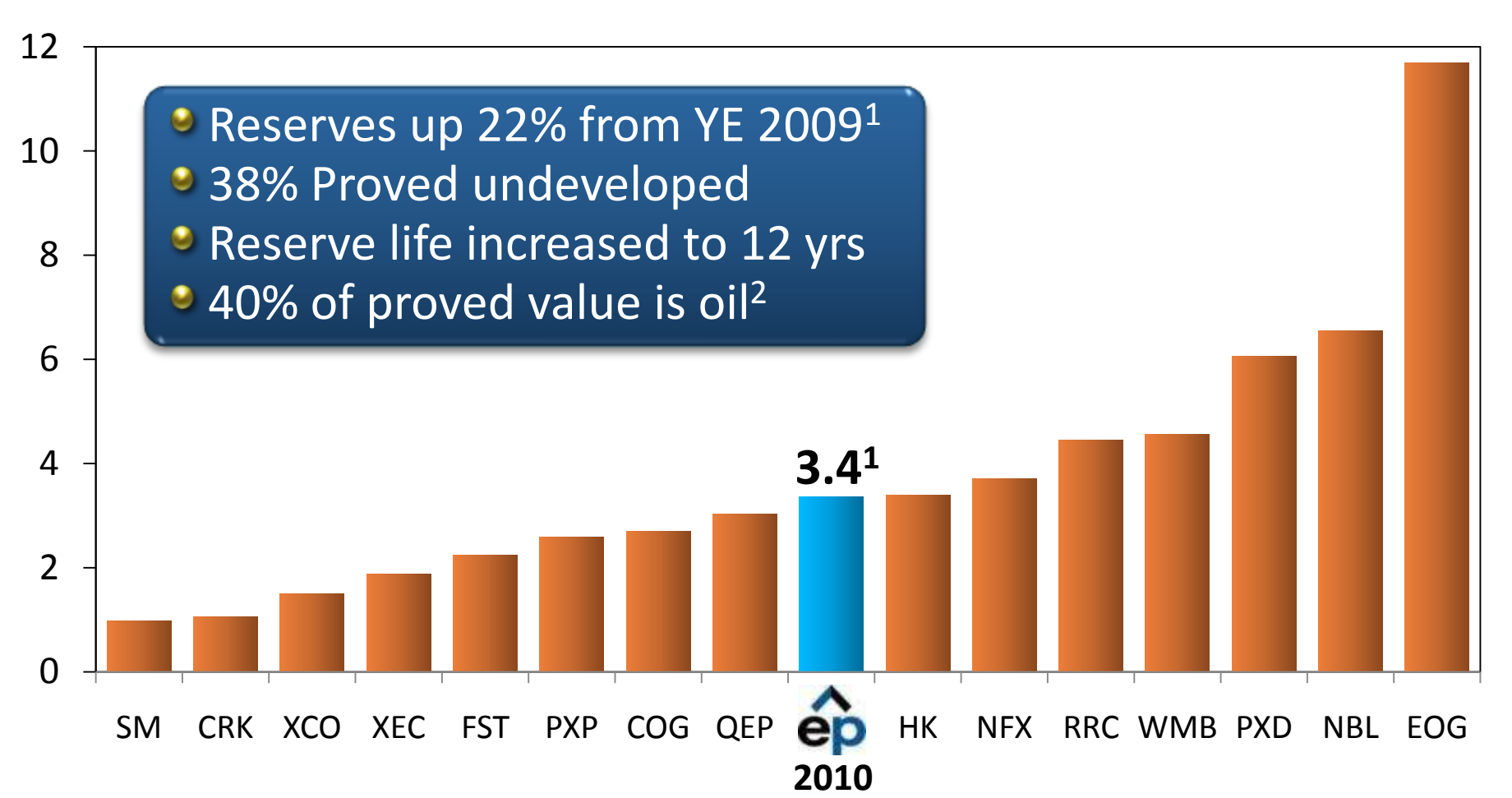


Maximizing Base Performance

- Improved reliability and management
- Pursuing value added investments
  - Workovers, restimulations, pump upgrades, facility de-bottlenecks
- Overall base decline ~35%

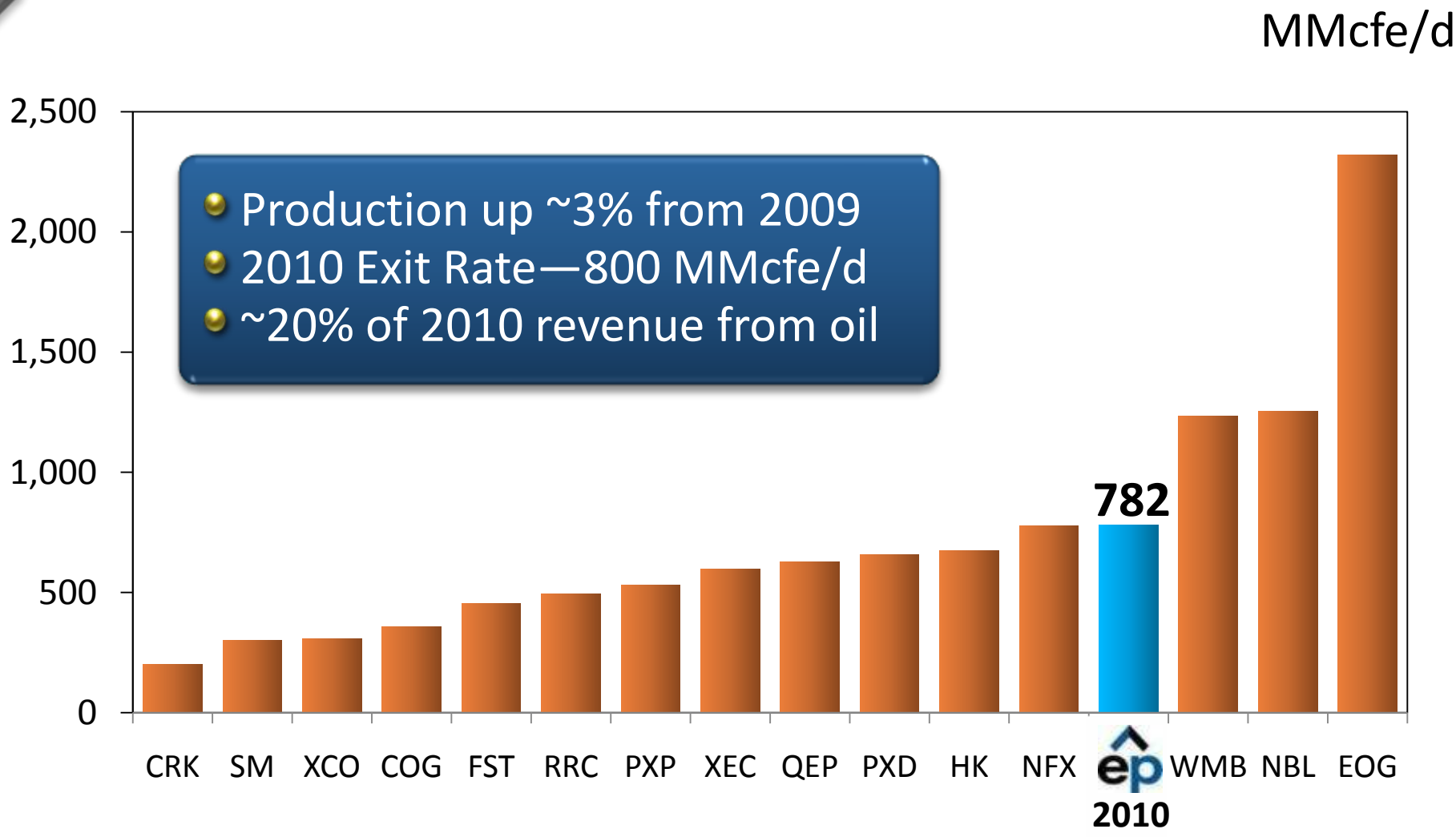


2010 Year-End Proved Reserves

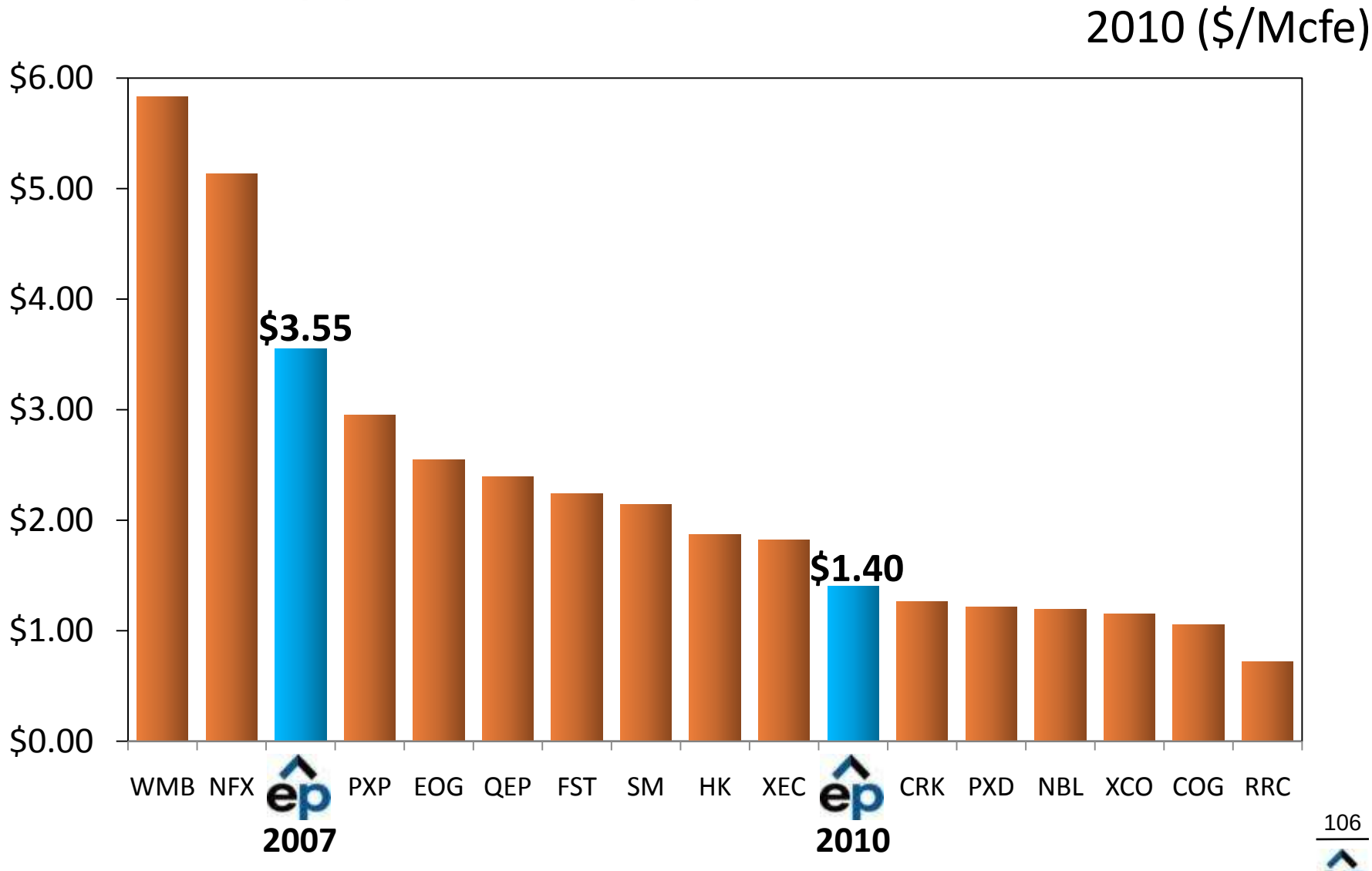


[1] Including the company's 48.8 percent interest in Four Star Oil & Gas Company
[2] Based on YE 2010 PV-10, which assumes 2010 pricing

2010 Average Daily Production

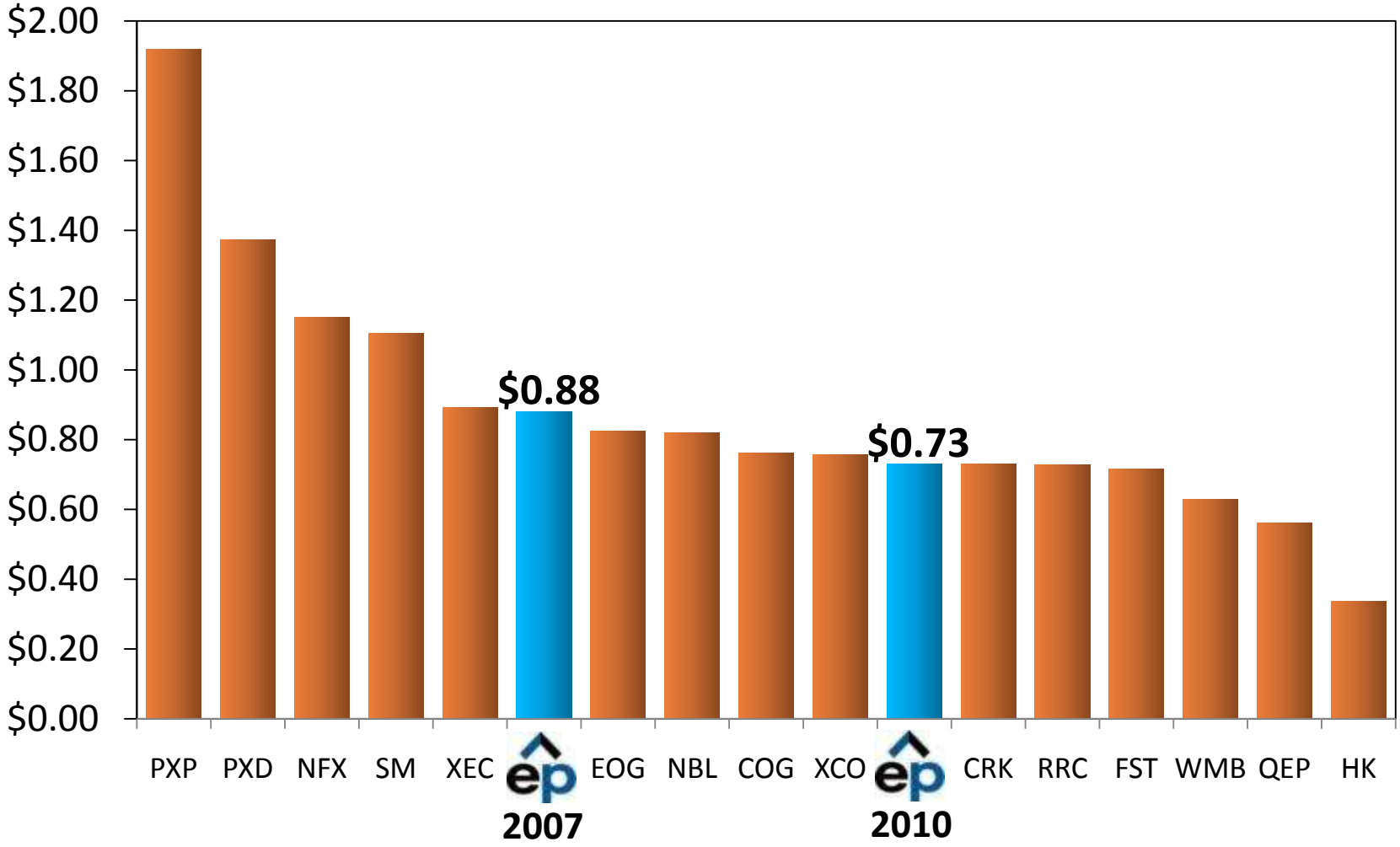


Reserve Replacement Costs Have Dropped Sharply



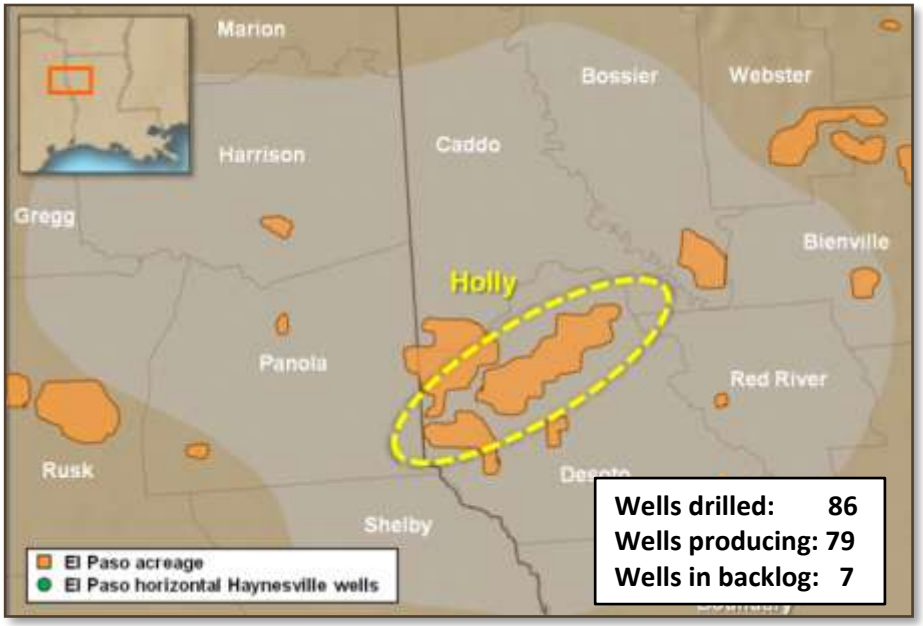
LOE Costs Have Also Improved

2010 ($/Mcfe)



Core Program Maturity

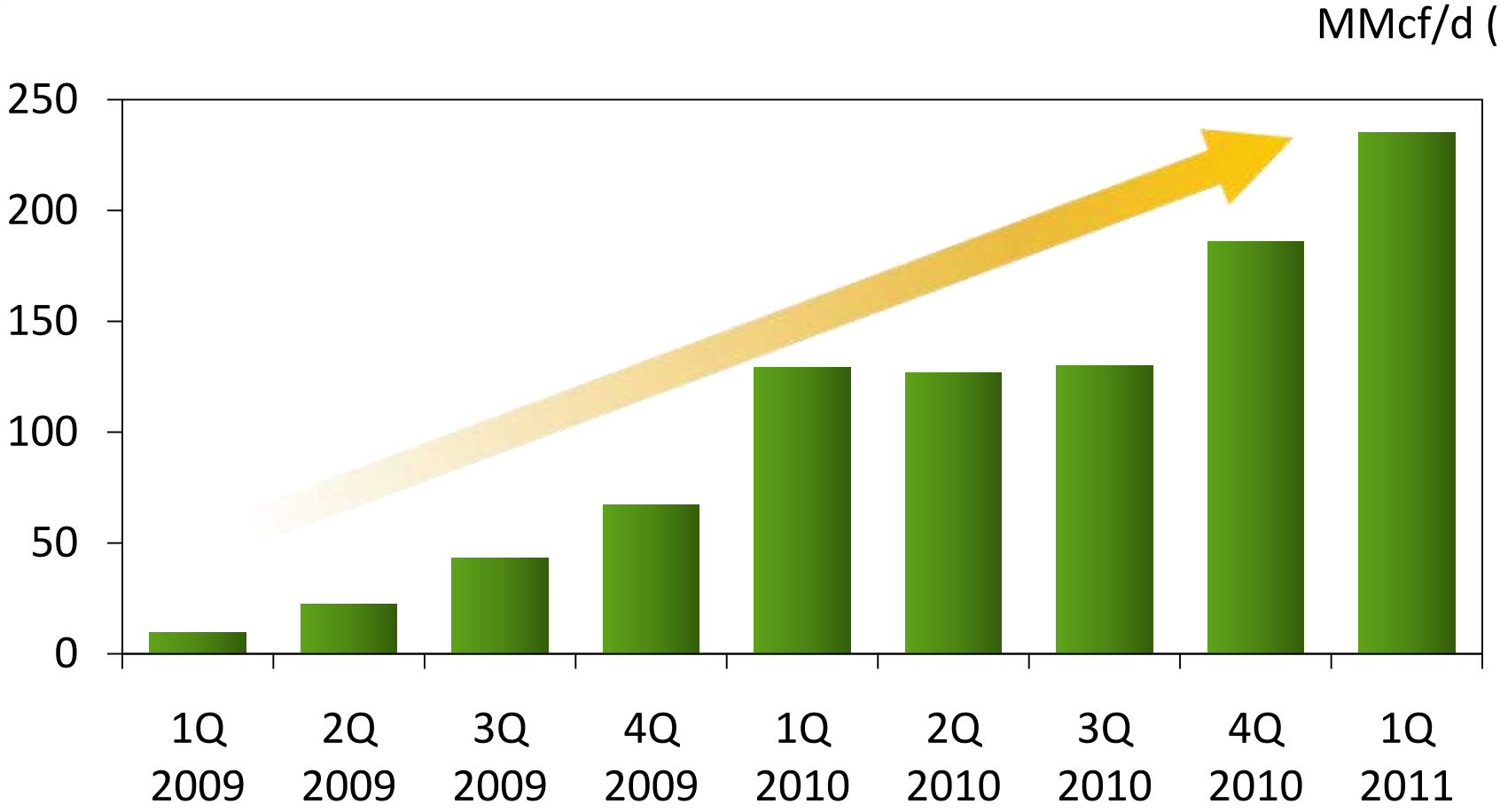
Haynesville Shale—
Premier Industry Program



Excellent position in the heart of the play

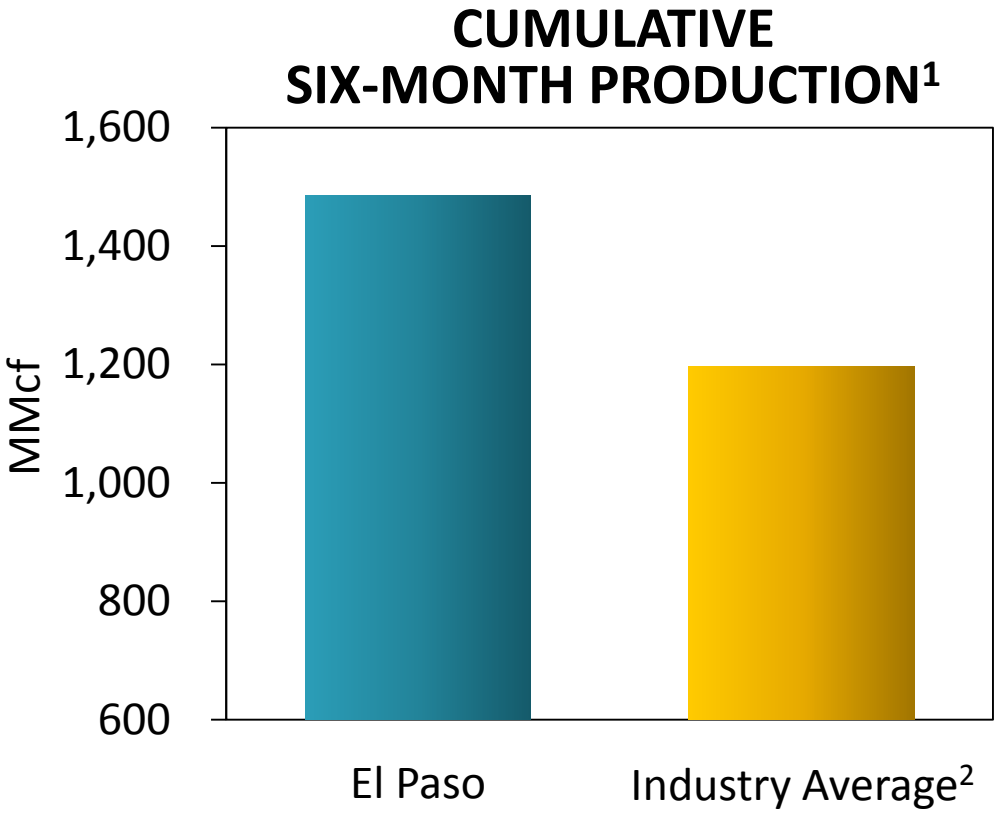
- Rapid production growth
- Top- or top-quartile program by any measure
- Holly area economic at sub $4 gas price
- Continue to drive efficiencies
- 4–5 year remaining inventory

Haynesville Production Growth



Current net production 265 MMcf/d

EP Wells nearly 20% More Productive than Industry



Higher productivity a function of:

- Excellent acreage position
- Well design optimization
  - Lateral length
  - Number of stages
  - Pumping rate
  - Total stage volumes
  - Proppant concentrations

[1] Cumulative six-month production based on available state reported production data as of April 2011
[2] Average per well based on newly producing horizontal gas wells in 2010 targeting the Haynesville Shale (deeper than 11,450 ft.)

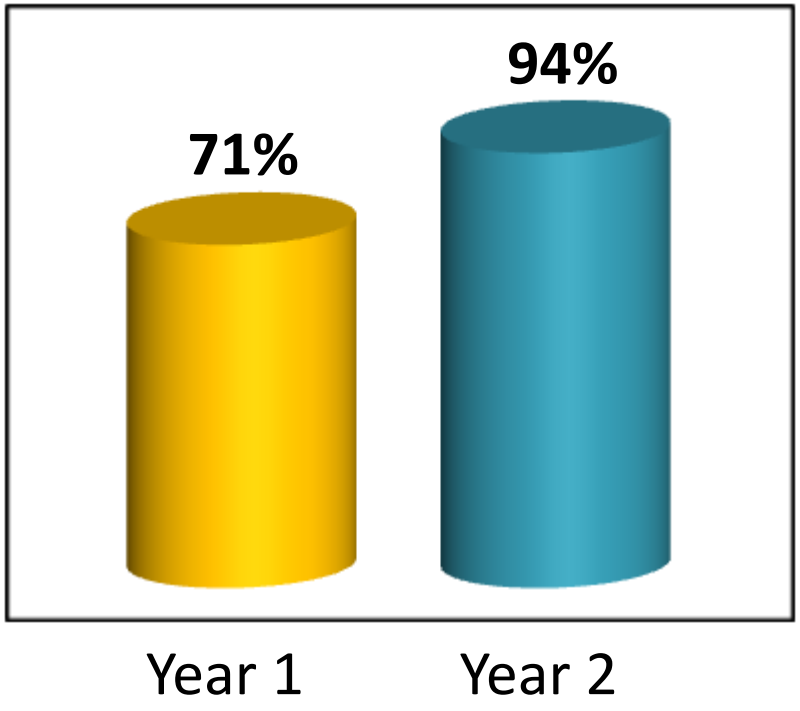
Haynesville Operational Success

Avg. Frac Stages Per Day

Haynesville (Holly) Performance Metrics

- Highest volume/capital efficiency in portfolio
- Lowest LOE/unit (~$0.05–$0.10/Mcfe)
- Best F&D of core programs ($1.55–$1.95 Mcfe)

CUMULATIVE EBITDA/CAPITAL @ $4.00/MCF (NYMEX)*



Anchor gas drilling program

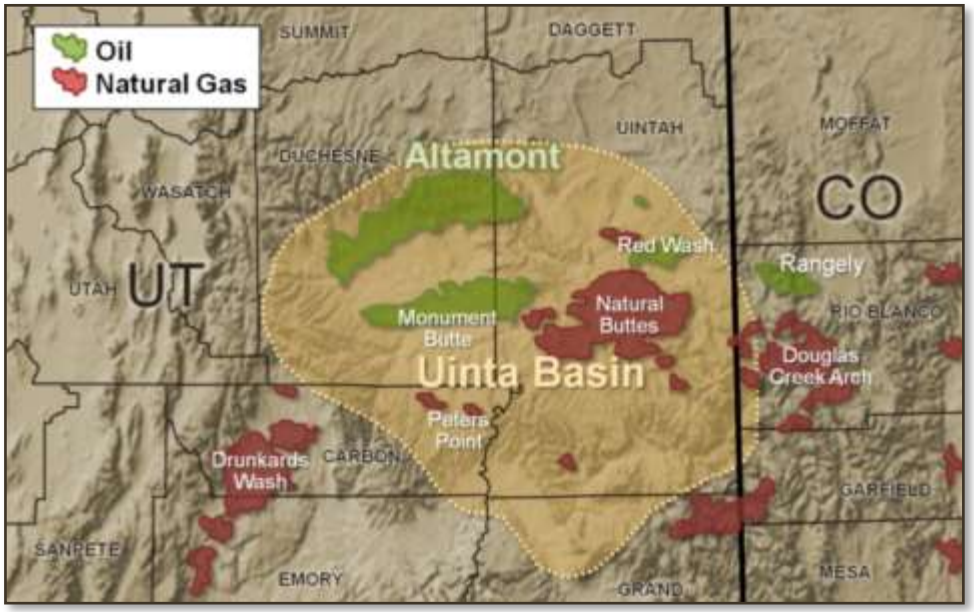
*Based on type model results for a single Holly area Haynesville well

Haynesville—Go Forward Plan

- Maintain 4-rig base-load program
- Continue to drive efficiencies
  - Drilling
  - Completion
    - Fracs per day
    - Frac design

Continue to deliver profitable growth

Altamont—Significant Oil Resource

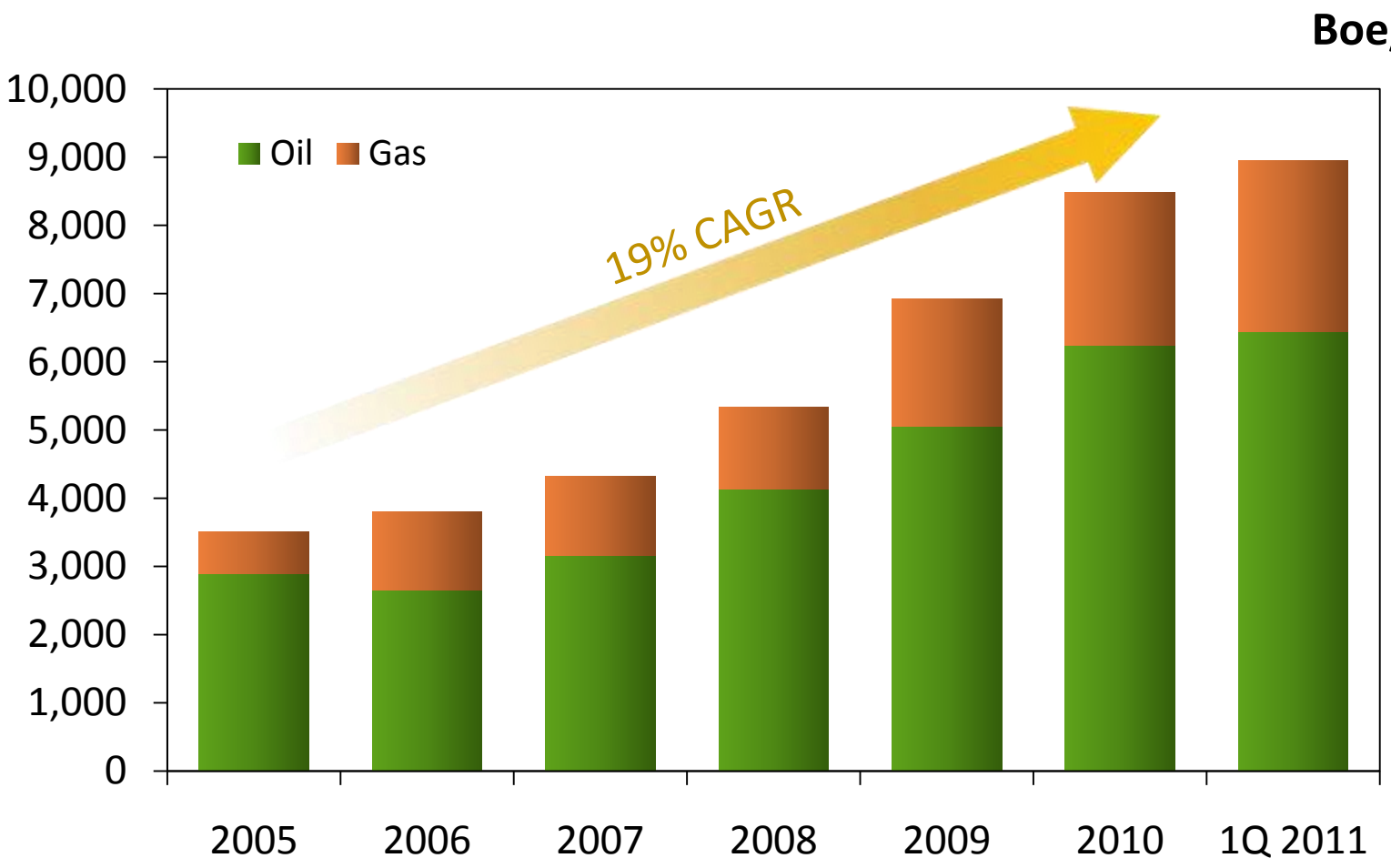


Applying new technologies to 3 billion barrel field

- Large oil inventory
  - >800 future locations
  - 125 MMboe resource*
- Substantial production growth potential
- Improved well productivity
- Continuous operational improvement

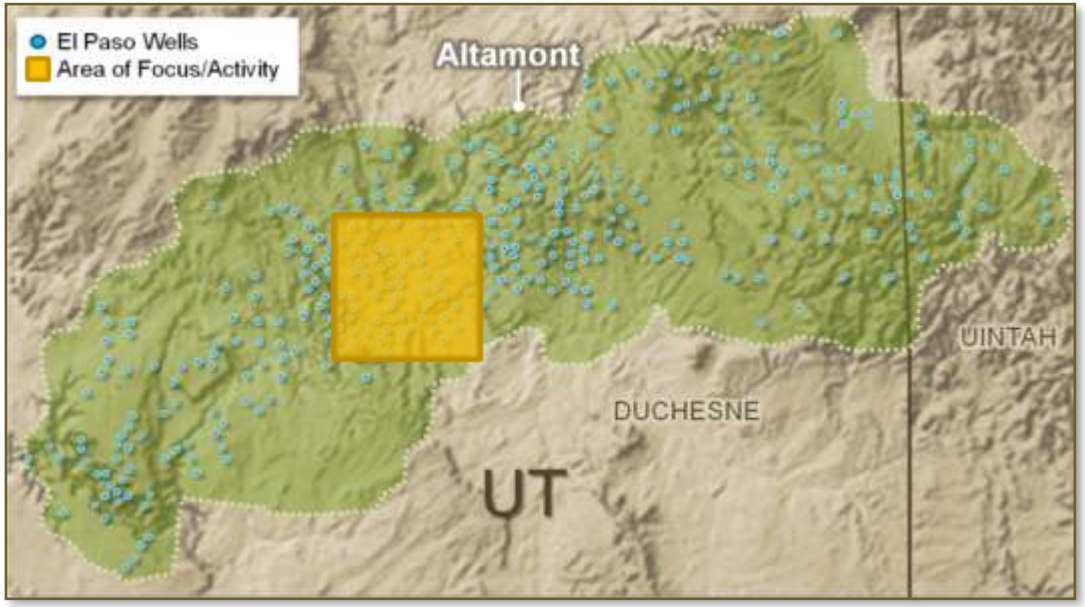
*As of December 31, 2010. Indicates risked resource potential

Altamont Production Growth



Current net production >9,000 Boe/d

Concentrated Infill Drilling Efforts

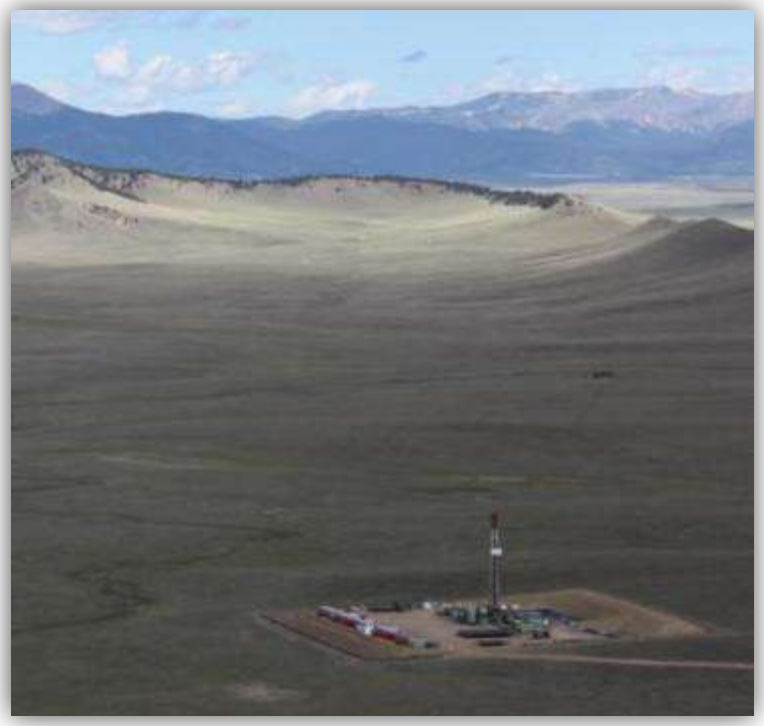


- Continue drilling in geographically focused areas
- Expected efficiency gains:
  - Shorter, more efficient rig moves
  - Repeatable drilling program execution
  - Optimized completion designs
  - Facility and artificial lift savings

Targeted capex savings of 20% per well

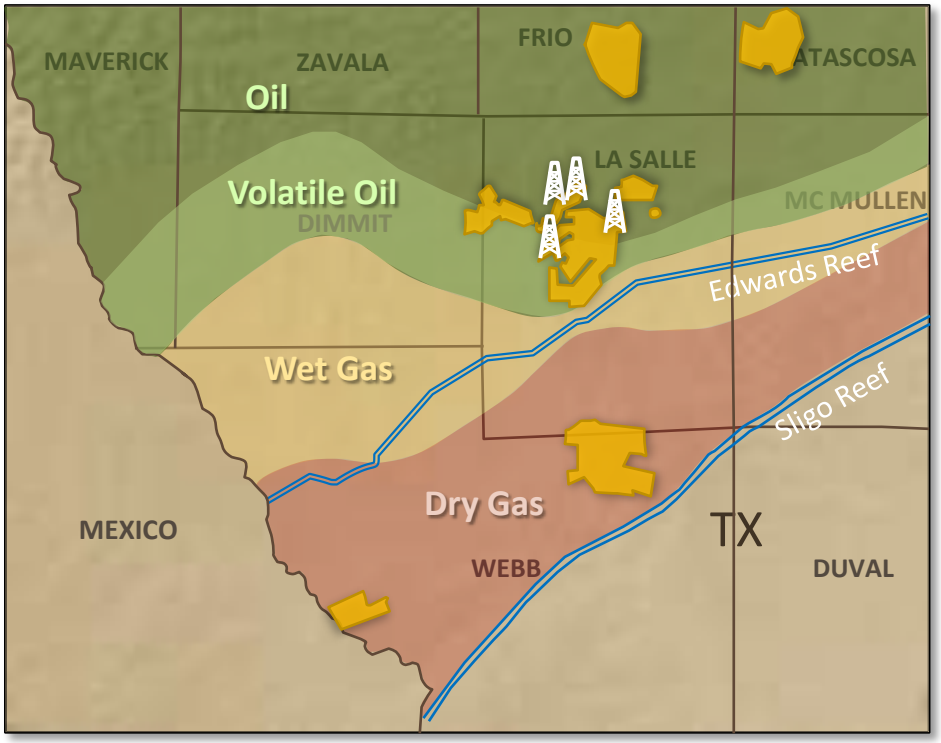
Altamont—Go Forward Plan

- Maintain active oil drilling program: 2–3 rigs
- Continue to drive efficiencies
  - Drilling
  - Vertical Well Completions
- Analyze 3-D seismic for natural fracture identification
- Evaluate EOR options



Long-term value and production growth

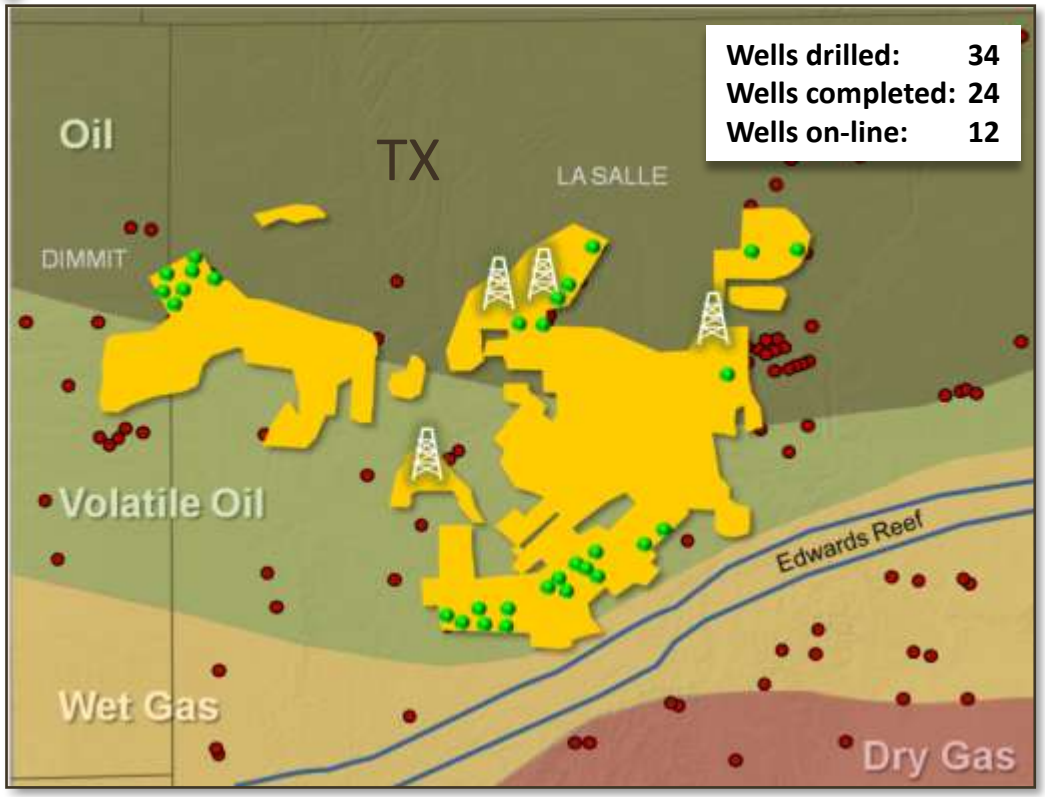
Eagle Ford—Flagship Program



Central area exceeding expectations

- Early mover with low acreage costs
- Advantaged acreage position in LaSalle county
  - In development mode
- Oil production growing rapidly
- Piloting phase in North
- Maintain gas option in South

Eagle Ford Central Activity



EP Leasehold

EP Completed / Completing Wells

Industry Eagle Ford Activity

Drilling Wells

- Delineation wells drilled across block
- Results at or above type model
- Improving drilling efficiencies
- Infrastructure under construction
- 4 rigs running

Production growth will accelerate in the second half of 2011

Positive Production Test Results

COMPLETED WELLS

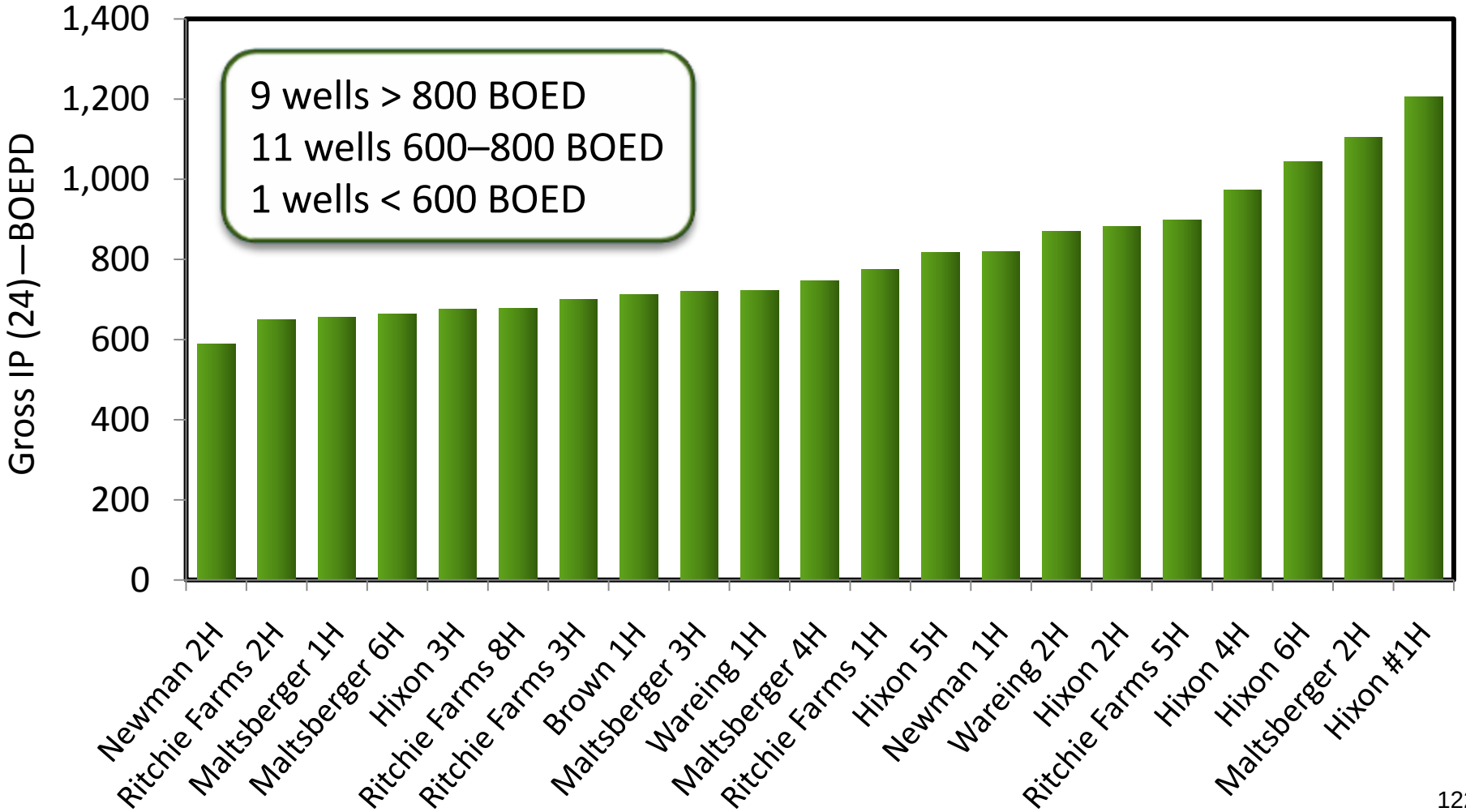
Area	No. of Wells	Lateral Length	No. of Stages	24 hr IP Gas (Mcf/d)	24 hr IP Oil (BOPD)	24 hr IP (BOEPD)
Average Volatile Oil	**11**	**4,400'**	**16**	**1501**	**588**	**839**
Hixon #1H*		4,139'	14	2859	728	1205
Average Oil	**10**	**4,700'**	**16**	**360**	**682**	**742**
Ritchie Farms #5H*		6,380'	21	327	844	898
Average Central	**21**	**4,550'**	**16**	**958**	**633**	**793**

DRILLING/COMPLETING

Area	# Wells	Lateral Length	Proposed No. of Stages
Volatile Oil	6	5,668'	19
Oil	7	5,350'	18
Total Central	**13**	**5,497'**	**18**

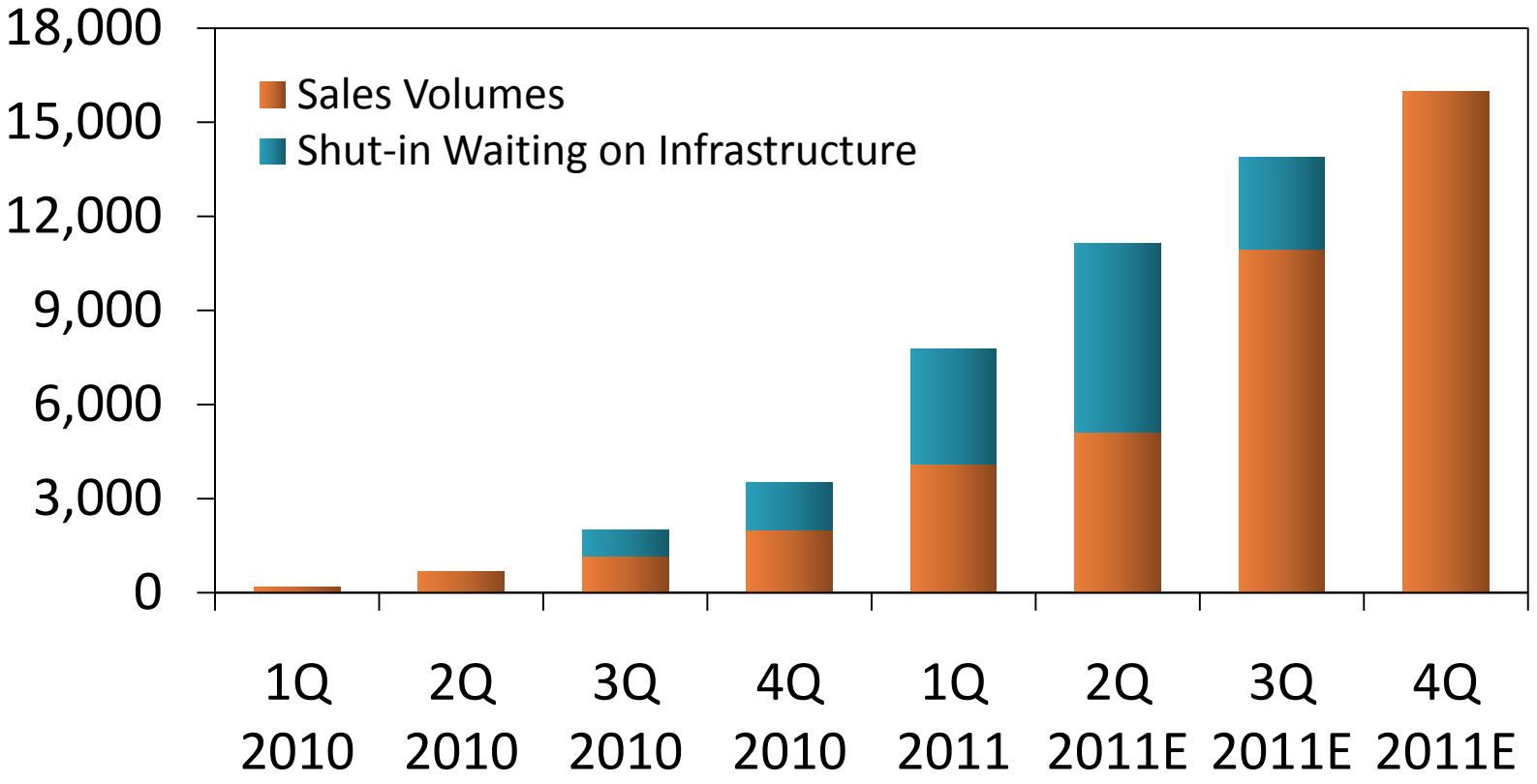
*Best well to date in area

IP Rates At or Above Model



Eagle Ford Production

Gross Volumes (BOED)



Current productive capacity
5,600 Bbl/d and 12 MMcf/d, net

Eagle Ford Central Type Wells & Potential

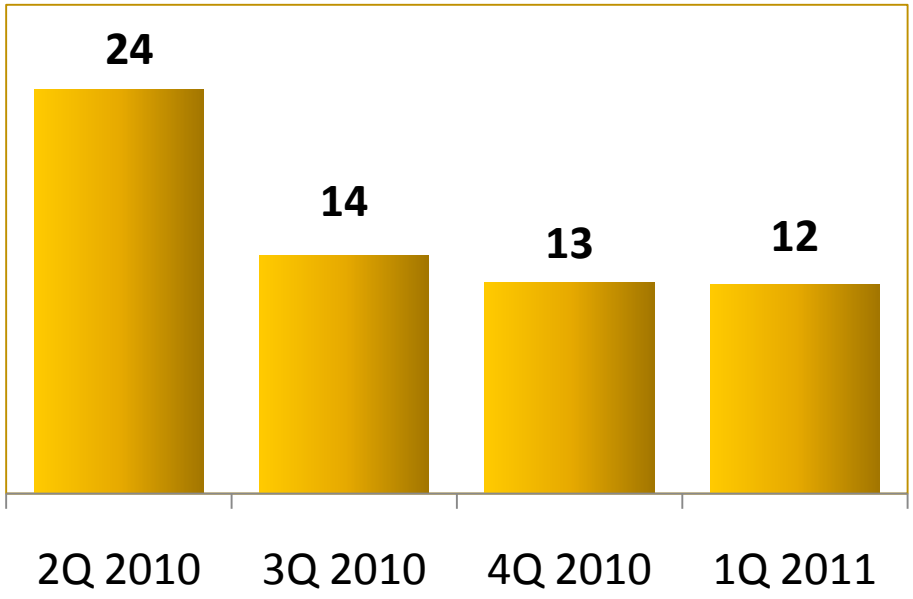
DEPTH	7,000'–10,000'
CAPITAL COST	$7.0 MM–$9.0 MM
LATERAL LENGTH	4,500’–5,500’
IP 24-HOUR (6:1)	600–1,100 BOED
EUR (6:1)	400–900 MBOE
IRR	25%–>50%
F&D (6:1)	$12–$20 ($/BOE)
WELL SPACING	120 acres
INVENTORY	>200 MMBOE, ~570 locations

Reducing spacing to 80 acres adds ~100 MMBOE & 280 locations

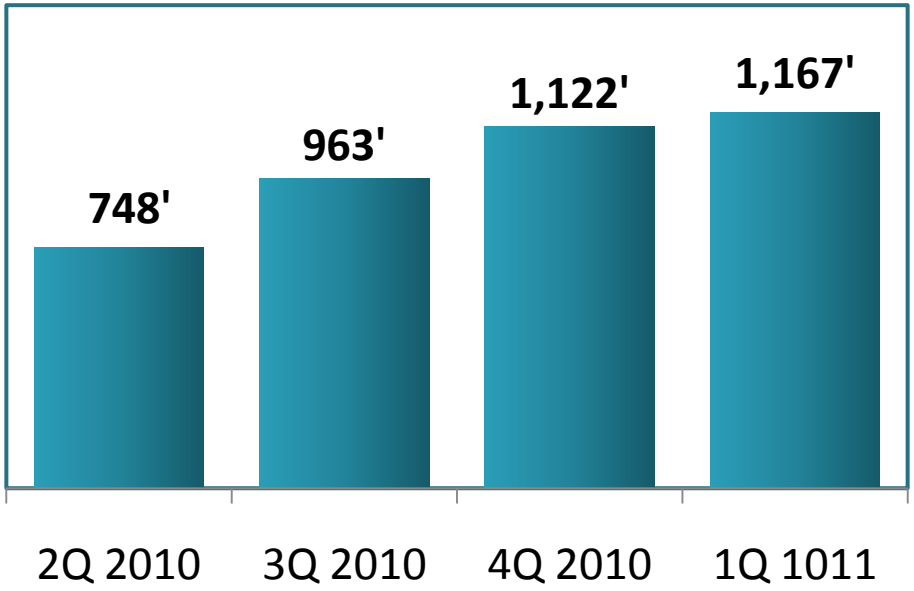
Economics assume $4.00/MMBtu Gas, $56/Bbl NGL and $80/Bbl Oil
Note: Capital, Production and EUR are gross numbers and do not account for royalties

Eagle Ford—Drilling Team Delivering

DRILLING DAYS
(Spud to Total Depth)*



DRILLING FEET PER DAY
(Ft/Day)*



2 rigs now doing the work of 3

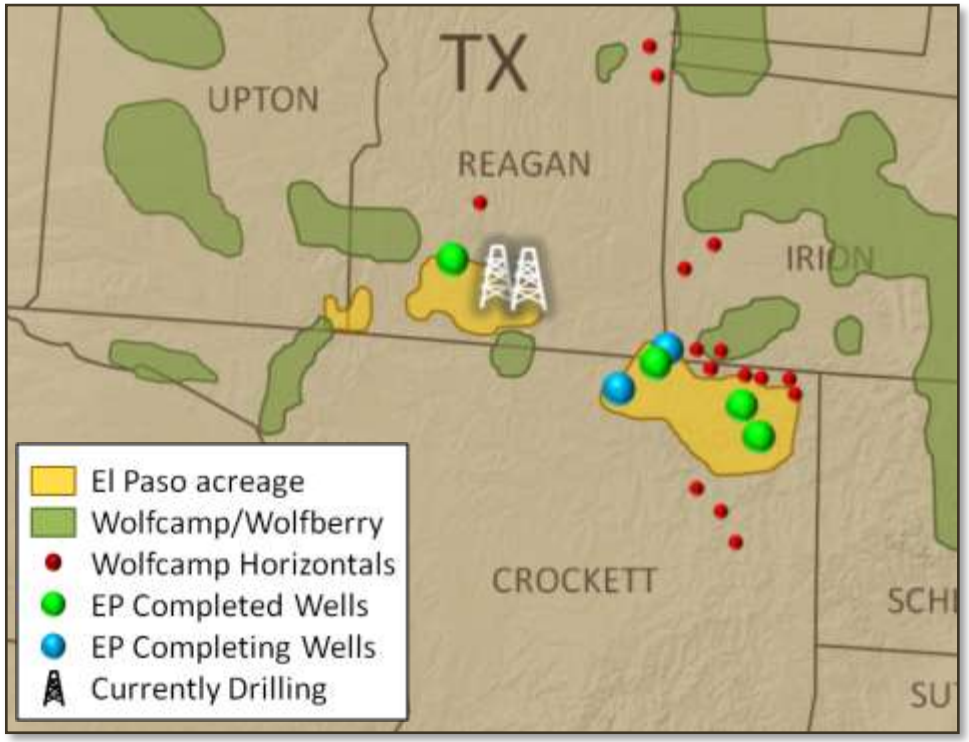
*Shows the average drilling time (spud to total depth) & average feet per day for all development wells drilled in each quarter; excludes pilot wells

Eagle Ford—Go Forward Plan

- Planning for annual rig growth to 5–7 rigs by 2013
- Further well optimization
  - Increase multi-pad drilling
  - Frac designs, lateral length
- Remain focused on Central area
- Evaluate 80–100 acre spacing units
- Pilot North area, maintain Southern gas

Highest oil production growth potential in portfolio

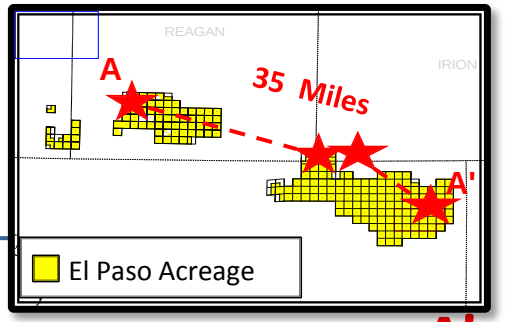
Wolfcamp Overview



Early mover with excellent position in emerging oil play

- Encouraging initial results
- Delineating acreage
- >800 locations—Upper Wolfcamp only
- Entire 138,000 acreage position unitized for 7-year term
- Optimizing: lateral length, frac stages, flow back rates, artificial lift

Consistent Thickness & Quality Across Acreage



A

El Paso 8-12 #1

El Paso 43-22 #1

EOG 40-14 #1

El Paso 39-7 #1

A'

Dean

Upper Wolfcamp

Lower Wolfcamp

WFMP

WFMPA

WFMPB

WFMPC

WFMPD

Gamma Ray

Organic Content

Porosity

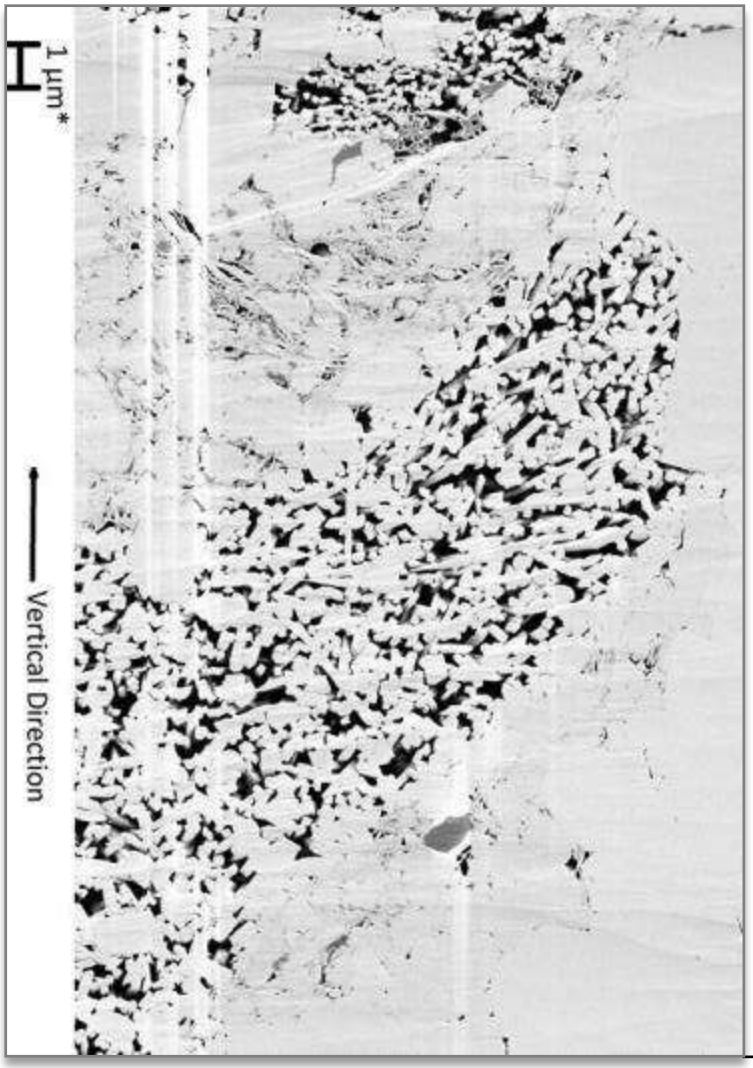
Lateral Placement

Lateral Length: 4,000' 4,000' 7000' 4,000'

Encouraged By Favorable Rock Characteristics

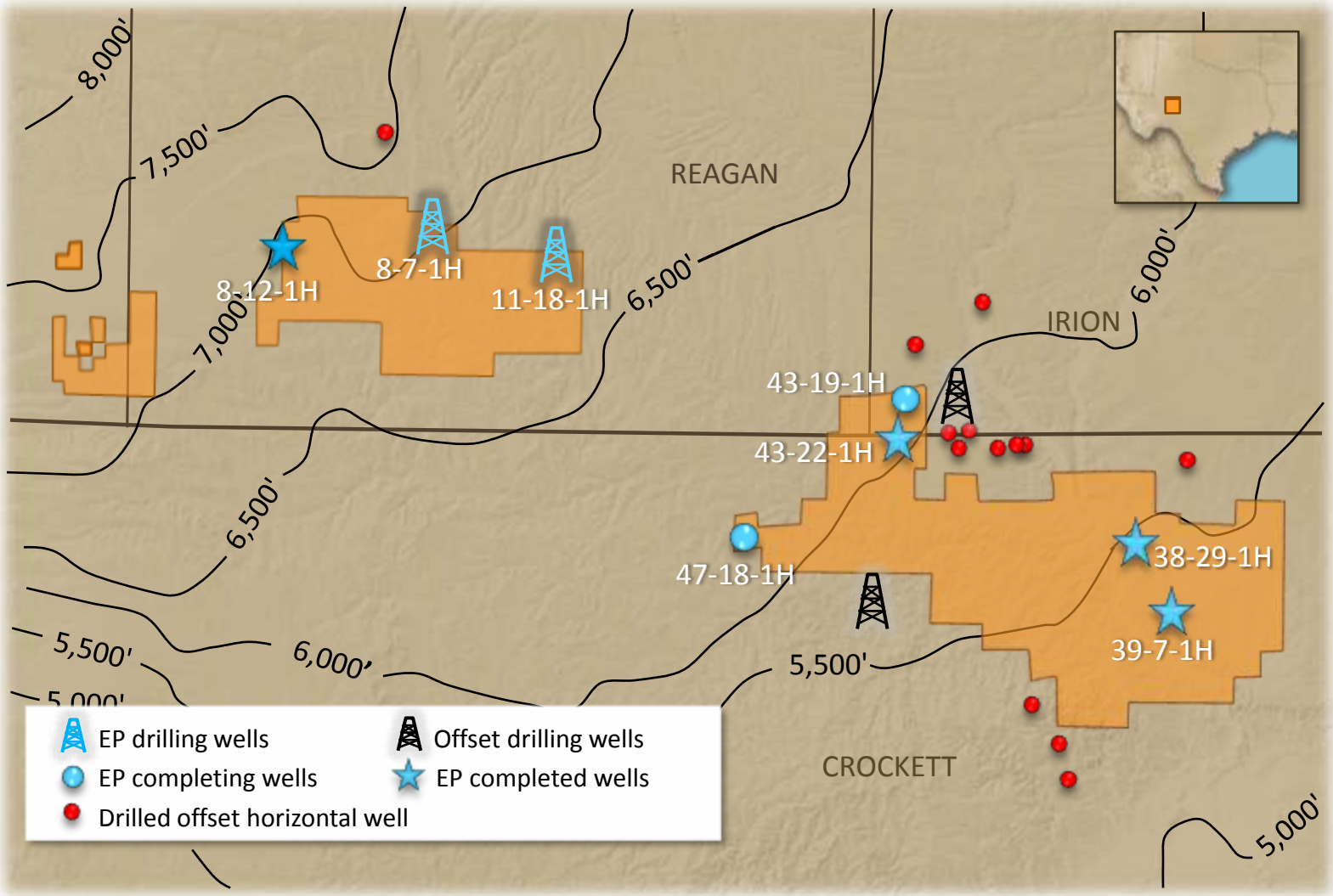
PARAMETER	MODEL	RESULTS
Depth Ft.	5,800–7,000	5,880–7,930
Thickness Ft.	400–850	976–1,080
Net Pay Ft.	200–425	544–680
Porosity %	7.0–15.0	9.4–12.0
Organic content	4.0–15.0	4.0–8.2

- Thicker gross section
- More net pay
- Better quality intervals
- Entire Wolfcamp section still perspective

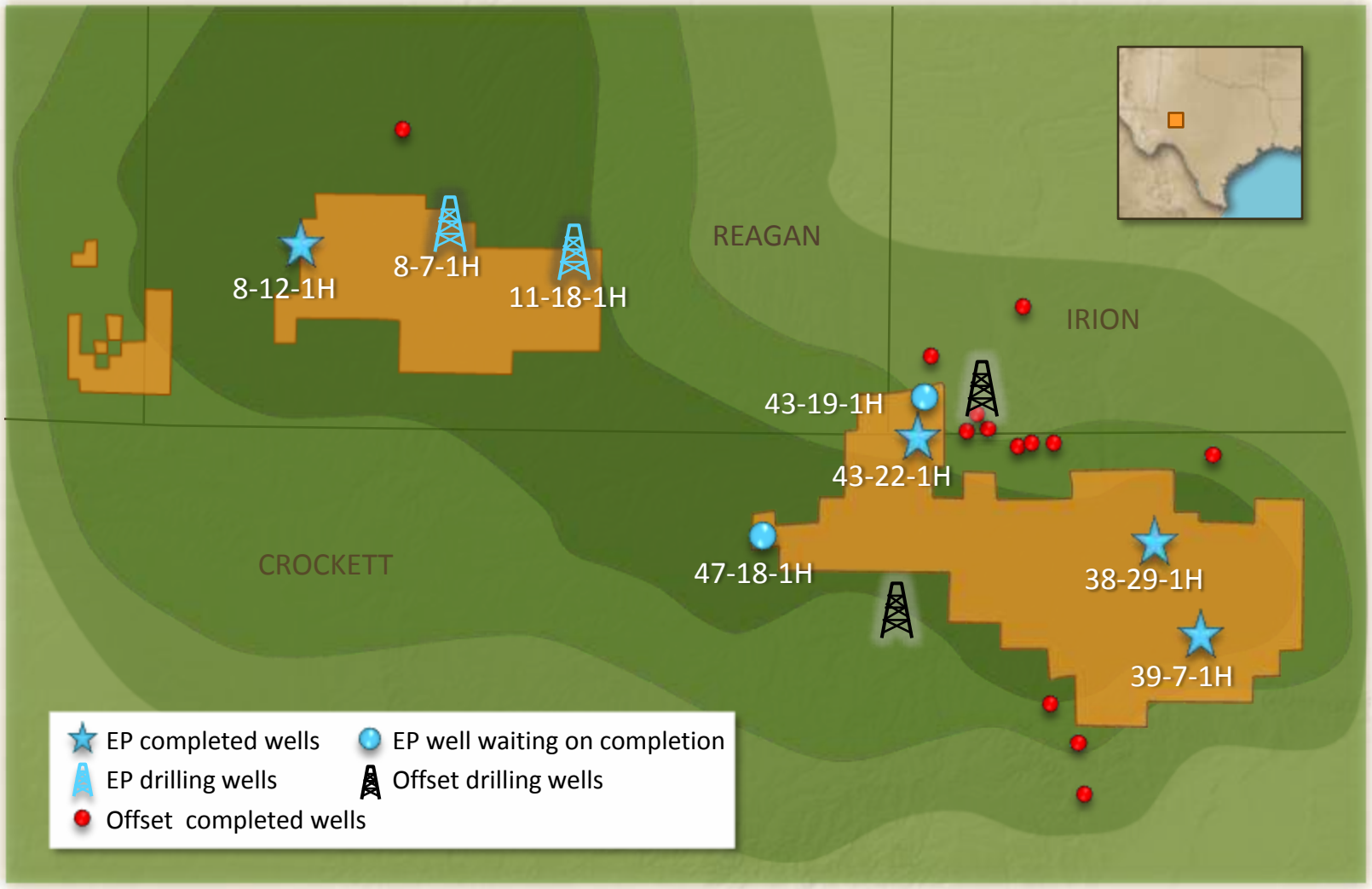


Note: Approximately 53% of section is Upper Wolfcamp

Wolfcamp Structure (TVD)



Wolfcamp Net Pay Thickness



Positive Production Test Results

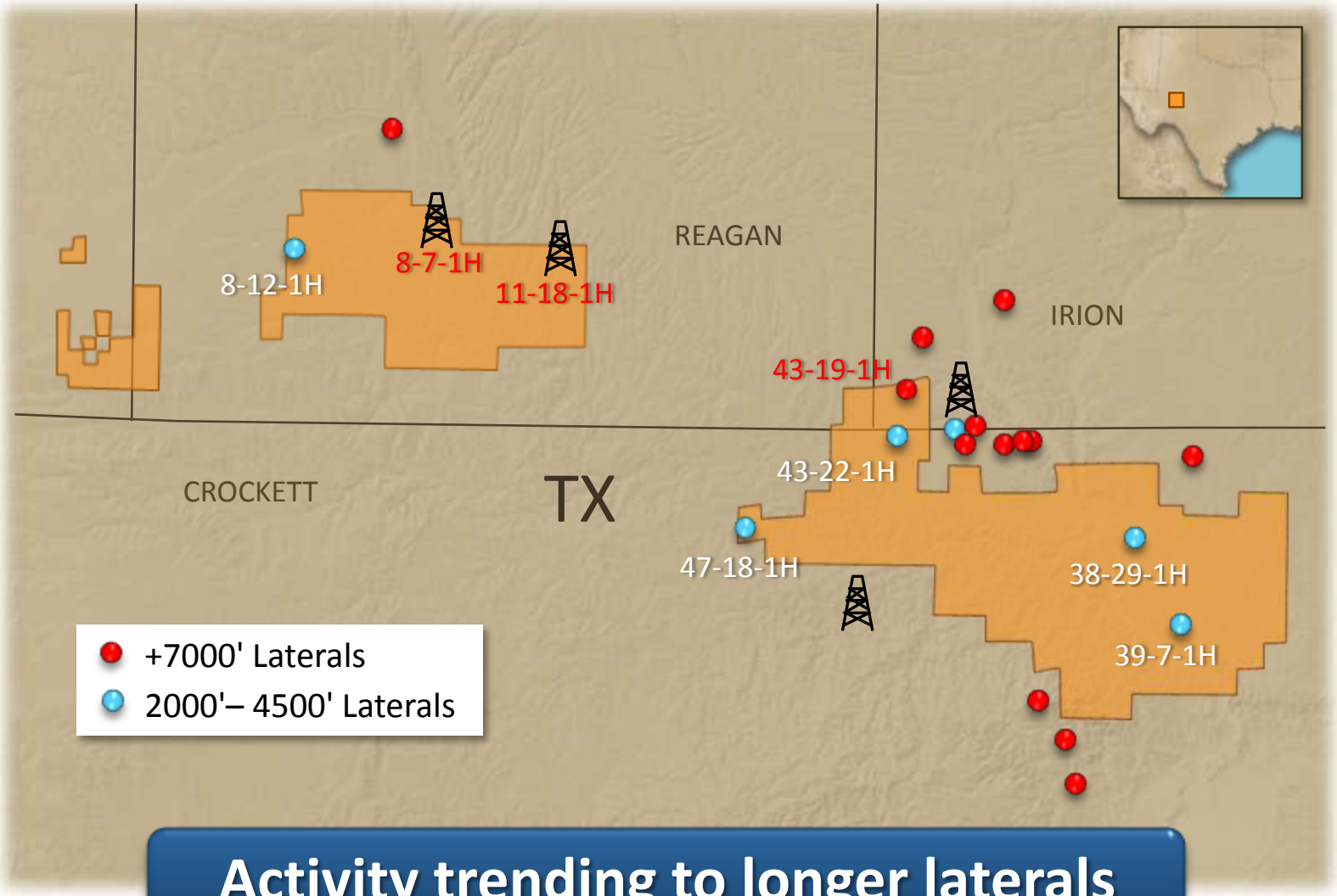
COMPLETED WELLS—IP 24 HR

Well	Lateral Length	No. of Stages	Gas (Mcf/d)	Oil (BOPD)	Equivalent (BOEPD)
TYPE MODEL	4,000–6,000	12–20	250–340	250–340	300–400
UL 38-29-1H (east)	2,000	7	115	273	292
UL 39-7-1H (east)	4,000	12	275	291	337
UL 43-22-1H (central)	3,600	13	341	335	393
UL 8-12-1H (west)	4,300	15	185	300	331

TO BE COMPLETED

Well	Lateral Length	Proposed No. of Stages
UL 43-19-1H (central)	7,000	24
UL 47-18-1H (central)	4,000	14

Wolfcamp Horizontal Activity



Activity trending to longer laterals

Lateral Length Comparison

WELL	LATERAL LENGTH	STAGES	STAGE SPACING	IP_{24}	IP_{24} PER STAGE
EP 39 7-1H	4,000	12	333	337	28
EP 43-22-1H	3,600	13	277	393	30
EP 812-1H	4,300	15	287	346	23
Average	**3,967**	**13**	**299**	**358**	**27**
Offset 1	7,400	21	352	667	32
Offset 2	7,700	24	321	747	31
Offset 3	6,300	16	394	568	35
Average	**7,133**	**20**	**356**	**661**	**33**

Longer laterals expected to increase production, EUR & value

Wolfcamp Path Forward

- Encouraged by early results
- Increased to 2-rig program
- Continuing to delineate acreage with opportunity to grow to 5–7 rigs by 2013
- Optimize development plan
  - Lateral length, frac stages, vertical vs. horizontal, artificial lift

Drilling Plans in Core Programs for Remainder of Year

- Eagle Ford: 3–4
  - Focus: Gain Efficiencies
- Wolfcamp: 2–3
  - Focus: Delineate acreage
- Haynesville: 4
  - Focus: Base load gas drilling
- Altamont: 2–3
  - Focus: Base load oil drilling

11–14 RIG PROGRAM

2011 capital increase to $1.6 B to drill 35 incremental net oil wells

Drivers for Capital Increase

- Accelerates development of highest value programs
- Advances oil production growth
- Results in higher 2011 exit rate
- Maintains momentum
  - Increases 2011 reserve adds
  - Operational efficiencies & safety benefits

Improves performance and value creation

Updated 2011 Guidance

	Original	Updated
Capital ($B)	$1.3	$1.6
Total production (MMcfe/d)	790–840	830–860
Oil production growth	30%–40%	35%–45%
Oil revenue growth	> 50%	> 65%
Unit cash costs ($/Mcfe)	$1.70–$1.90	$1.70–$1.85
DD&A rate ($/Mcfe)	$1.90–$2.10	$2.05–$2.15

Note: Updated guidance assumes $4.50/MMBtu Gas (NYMEX) and $107/Bbl Oil (WTI)

Summary

- Executing—Strategy, Portfolio, & People
- Inventory is large and profitable with oil and gas options
- Core programs performing very well
- Delivering attractive returns
- Have built capacity for double-digit growth
  - Production
  - EBITDA—Greater growth rate than production due to oil revenues

Will continue top-tier performance

An Exciting New Chapter

- Creating two enduring public companies
- Each with a bright future
- Management in place and energized
- Each will be well capitalized
- Focus on execution will remain

Tremendous outcome for all our stakeholders

Appendix

Financial

Disclosure of Non-GAAP Financial Measures

The SEC's Regulation G applies to any public disclosure or release of material information that includes a non-GAAP financial measure. In the event of such a disclosure or release, Regulation G requires (i) the presentation of the most directly comparable financial measure calculated and presented in accordance with GAAP and (ii) a reconciliation of the differences between the non-GAAP financial measure presented and the most directly comparable financial measure calculated and presented in accordance with GAAP. The required presentations and reconciliations are attached, or included in the body of this presentation.

El Paso uses the non-GAAP financial measure "Segment earnings before interest expense and income taxes" or "Segment EBIT" to assess the operating results and effectiveness of the company and its business segments. The company believes that Segment EBIT is useful to its investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or the company's capital structure. The company defines Segment EBIT as net income (loss) adjusted for interest and debt expense and income taxes. Segment EBIT does not reflect a reduction for any amounts attributable to noncontrolling interests. We also use the non-GAAP financial measure of Segment EBITDA, which is defined as Segment EBIT excluding depreciation, depletion and amortization.

El Paso also uses the terms Adjusted Segment EBIT, Adjusted Segment EBITDA and Adjusted EPS as the company believes these measures are useful to investors in analyzing the company's on-going earnings potential. For its 2011 outlook, the company defines Adjusted Segment EBIT as Segment EBIT excluding mark-to-market impact of E&P financial derivatives and including anticipated cash settlement proceeds of E&P financial derivatives based on guidance assumption prices. Adjusted Segment EBITDA is defined as Adjusted Segment EBIT excluding depreciation, depletion and amortization. For the company's 2011 outlook, Adjusted EPS is defined as earnings per share attributable to El Paso Corporation common stockholders, excluding losses on debt extinguishment and anticipated mark-to-market impact of E&P financial derivatives and including anticipated cash settlement proceeds of E&P financial derivatives and the effect of the change in the number of diluted shares.

Our Exploration and Production segment uses per-unit total cash operating costs is a non-GAAP measure calculated on a per Mcfe basis equal to total operating expenses less DD&A, transportation costs, ceiling test and other impairment charges, and the cost of products and services, divided by total equivalent production. Exploration and Production per-unit lease operating expenses is a non-GAAP measure calculated on a per Mcfe basis equal to lease operating expenses divided by total equivalent production. The sum of lease operating expenses and production taxes equals production costs. The sum of production costs, cost of products, transportation costs, DD&A, G&A, ceiling test and other impairment charges and other operating expenses equals total operating expenses. Per-unit total cash operating costs and per-unit lease operating expenses are valuable measures used by oil and gas companies and analysts to evaluate operating performance and efficiency.

The company's Exploration and Production segment also utilizes the terms Reserve Replacement Costs or "RRC" and Reserve Replacement Ratio or "RRR." These measures are discussed further in this appendix.

El Paso uses the compound annual growth rate or "CAGR", which is the average annual growth rate over a period of years. The company believes this metric is useful for investors because it displays the historical or projected performance over time. Compounded growth rates are the industry standard of measurement within the investment community and therefore El Paso feels it is preferred to using the simple average of year-to-year growth rates.

El Paso believes that the non-GAAP financial measures described above are also useful to investors because these measurements are used by many companies in the industry as a measurement of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance of the company and its business segments and to compare the operating and financial performance of the company and its business segments with the performance of other companies within the industry.

These non-GAAP financial measures may not be comparable to similarly titled measurements used by other companies and should not be used as a substitute for net income, earnings per share or other GAAP operating measurements.

Reserve Metrics

We calculate two primary metrics, (i) a reserve replacement ratio and (ii) reserve replacement costs, to measure our ability to establish a long-term trend of adding reserves at a reasonable cost in our core asset areas. The reserve replacement ratio is an indicator of our ability to replenish annual production volumes and grow our reserves. It is important for us to economically find and develop new reserves that will more than offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves. In addition, we calculate reserve replacement costs to assess the cost of adding reserves which is ultimately included in depreciation, depletion and amortization expense. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our asset areas at lower costs than our competition. We calculate these metrics as follows:

Reserve replacement ratio $\dfrac{\text{Sum of reserve additions}^{1}}{\text{Actual production for the corresponding period}}$

Reserve replacement costs/Mcfe $\dfrac{\text{Total oil and gas capital costs}^{2}}{\text{Sum of reserve additions}^{1}}$

We show the calculation of domestic reserve replacement costs excluding the impact of acquisitions, performance and price-related revisions on reserves to demonstrate the effectiveness of our domestic drilling program exclusive of economic factors (such as price) outside of our control.

The reserve replacement ratio and reserve replacement costs per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

The exploration for and the acquisition and development of natural gas and oil reserves is inherently uncertain as further discussed in the Company's SEC filings. One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped.

[1]Reserve additions include proved reserves and reflect reserve revisions for prices and performance, extensions, discoveries and other additions and acquisitions and do not include unproved reserve quantities or proved reserve additions attributable to investments accounted for using the equity method. All amounts except for 2011 estimates are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations in the company's 2010 Annual Report on Form 10-K.

[2]Total oil and gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. All amounts except for 2011 estimates are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations in the company's 2010 Annual Report on Form 10-K.

Updated 2011 Segment Guidance[1]

$ Billions

	PIPELINES	E&P	OTHER	TOTAL
Adjusted segment EBIT	$1.7–$1.8	$0.7–$0.8	$(0.1)	**$2.3–$2.5**
Adjusted segment EBITDA	$2.2 –$2.3	$1.3–$1.4	$(0.1)	**$3.4 –$3.6**
Capital	$1.8	$1.6	$0.2	**$3.6**

[1] Updated guidance assumes $4.50/MMBtu (NYMEX) and $107/Bbl (WTI)

2011 Segment EBIT & Segment EBITDA Reconciliation

($ Billions)	Twelve Months Ending December 31, 2011
Adjusted Segment EBITDA[1]	$3.4–$3.6
Less: DD&A	1.1
Adjusted Segment EBIT[1]	$2.3–$2.5
Less: Interest and debt expense	0.9
Less: Income taxes	0.3–0.4
Adjusted net income[1]	**$1.1–$1.2**
Adjustments related to derivatives and other[1,2]	0.3
Net income	**$0.8–$0.9**

[1]Adjustments exclude losses on debt extinguishment and the mark-to-market impact of E&P financial derivatives and include cash settlement proceeds of E&P financial derivatives based on guidance assumption prices
[2]All adjustments assume a 36% tax rate

Adjusted EPS Reconciliation

($ Billions, Except EPS)	After-tax	Diluted EPS
Net income attributable to EPC common stockholders	$0.5–$0.6	$0.62–$0.72
Adjustments related to derivatives and other[1]	0.3	0.38
Adjusted net income attributable to EPC common stockholders	**$0.8–$0.9**	**$1.00–$1.10**

[1]Adjustments exclude losses on debt extinguishment and the mark-to-market impact of E&P financial derivatives and include cash settlement proceeds of E&P financial derivatives based on guidance assumption prices. All adjustments assume a 36% tax rate.

Production Related Derivative Schedule

Natural Gas	2011		2012		2013	
	Notional Volume (TBtu)	Average Hedge Price	Notional Volume (TBtu)	Average Hedge Price	Notional Volume (TBtu)	Average Hedge Price
Economic - EPEP						
Fixed Price - Legacy	3.5	$3.88	2.3	$3.93		
Fixed Price	130.7	$5.75	102.2	$6.06		
Fixed Price - Extendible[1]	5.5	$6.07				
Collars - Ceiling	13.8	$7.29				
Collars - Floor	13.8	$6.00				
Avg Ceiling	153.4	$5.86	104.5	$6.01		
Avg Floor	153.4	$5.74	104.5	$6.01		

Crude Oil	2011		2012		2013		2014		2015	
	Notional Volume (MMbbls)	Average Hedge Price	Notional Volume (MMbbls)	Average Hedge Price	Notional Volume (MMbbls)	Average Hedge Price	Notional Volume (MMbbls)	Average Hedge Price	Notional Volume (MMbbls)	Average Hedge Price
Economic - EPEP										
Fixed Price	1.51	$87.54	0.64	$100.13						
Written Calls - Ceiling			1.46	$95.00	2.92	$96.88	1.10	$100.00	1.10	$100.00
Three-Way Collars - Ceiling	2.75	$94.27	5.76	$114.16	1.55	$128.34				
Three-Way Collars - Floor[2]	2.75	$85.14	5.76	$92.54	1.55	$100.00				
Three-Way Collars - Floor	2.75	$65.00	5.76	$67.54	1.55	$75.00				
Avg Ceiling	4.26	$91.88	7.86	$109.46	4.47	$107.79	1.10	$100.00	1.10	$100.00
Avg Floor[2]	4.26	$85.99	6.40	$93.30	1.55	$100.00				

Note: U.S. Domestic positions are as of May 17, 2011 (contract months: April 2011 – Forward)
[1]Swap option not extended by counterparty in 2012 due to low prices
[2]Three-Way Collars – Average floor is calculated using the highest floor

Exploration & Production Program Updates

Haynesville Holly

20,000 net acres

Program Statistics

- Operated producing wells[1]: 43
- Average WI[2]: 85 %
- Average NRI[2]: 70 %
- Future drilling locations[3]: 269
  - Operated: 138
- PUD reserves: 306 Bcfe
- Unrisked resource potential[3]: 520 Bcfe
- Risked resource potential[3]: 520 Bcfe
- Spacing: 107 acre (6 wells/section)

[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

Haynesville Non-Holly

20,000 net acres

Program Statistics

- Operated producing wells[1]: 15
- Average WI[2]: 70 %
- Average NRI[2]: 52 %
- Future drilling locations[3]: 147
  - Operated: 90
- PUD reserves: 67 Bcfe
- Unrisked resource potential[3]: 280 Bcfe
- Risked resource potential[3]: 280 Bcfe
- Spacing: 160 acre (4 wells/section)

[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

Haynesville Economics

HOLLY AREA

Overview

- Objective: Haynesville Shale
- Depth: 11,000'–12,500'
- Lateral length: 4,300’–4,600’
- Capital costs: $8.7–$9.3 MM
- EUR (Gross): 6.0–7.0 Bcfe
- Initial prod: 15–25 MMcfe/d
- IP(30): 12–20 MMcfe/d

Metrics ($4.00/MMBtu, $80/Bbl)

- IRR: 20%–30%
- PVR: 1.10–1.20
- F&D costs: $1.55–$1.95/Mcfe

NON-HOLLY

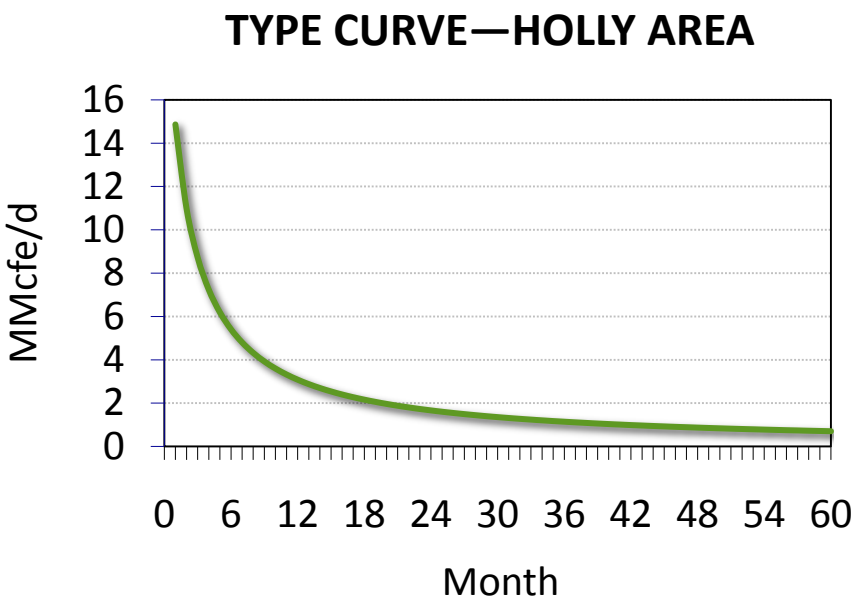
Overview

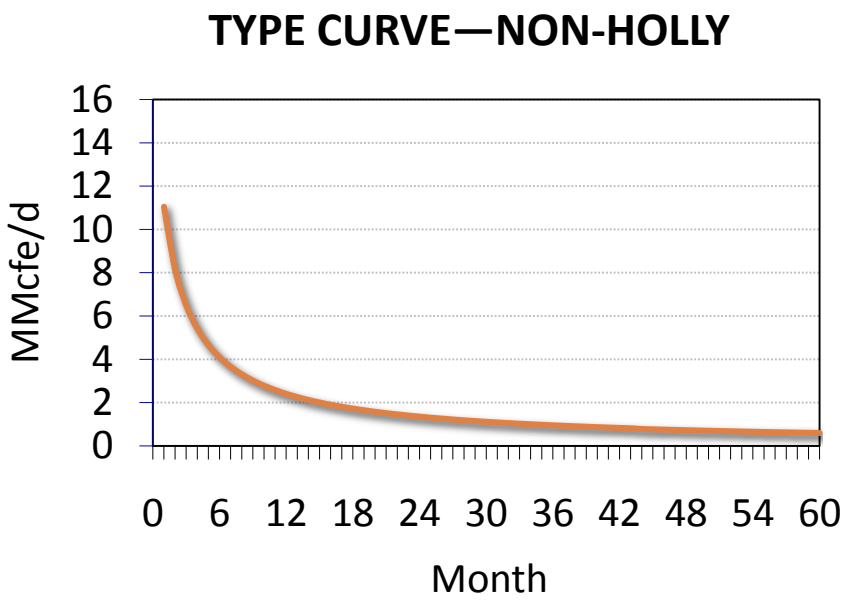
- Objective: Haynesville Shale
- Depth: 11,000'–12,500'
- Lateral length: 4,300’–4,600’
- Capital costs: $8.7–$9.3 MM
- EUR (Gross): 5.0–6.0 Bcfe
- Initial prod: 9–19 MMcfe/d
- IP(30): 6–15 MMcfe/d

Metrics ($4.00/MMBtu, $80/Bbl)

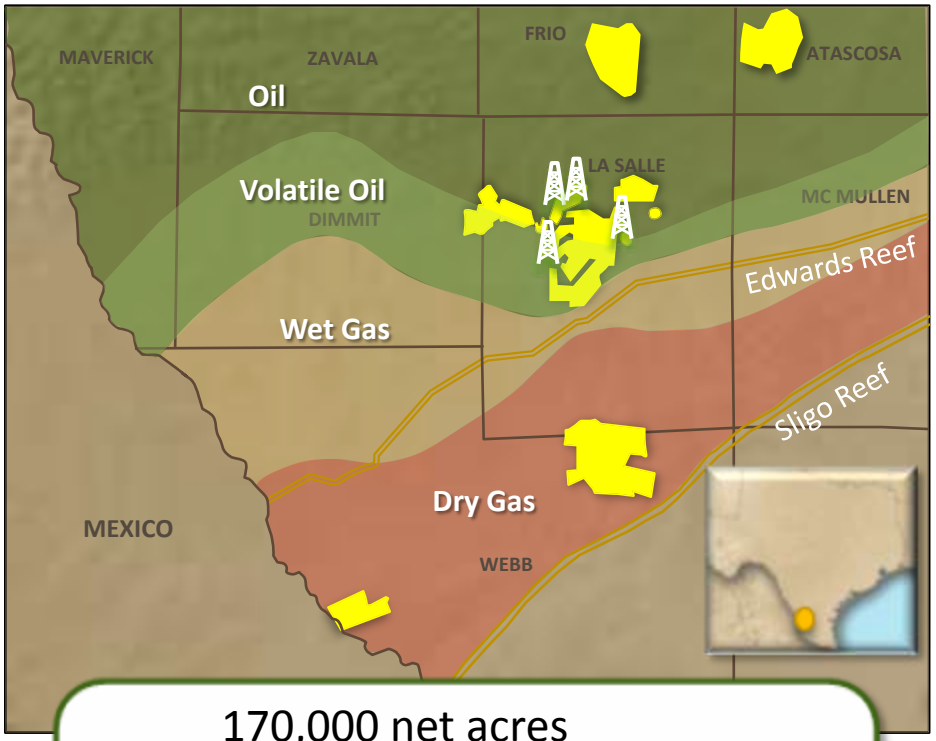
- IRR: 5%–15%
- PVR: 0.9 – 1.0
- F&D costs: $1.80–$2.35/Mcfe

Haynesville Decline Profiles





Eagle Ford



170,000 net acres
- 65,000 net acres dry gas
- 105,000 net acres oil
  - 74,000 central
  - 31,000 north

PROGRAM STATISTICS

- Operated producing wells[1]: 9
- Average WI[2]: 93 %
- Average NRI[2]: 70 %
- Future drilling locations[3]: 1,145
  - 100% operated
- PUD reserves: 25 MMBOE
- Unrisked resource potential[3]: 550 MMBOE
- Risked resource potential[3]: 395 MMBOE
- Spacing:

North	120 acre
Central	120 acre
South	160 acre

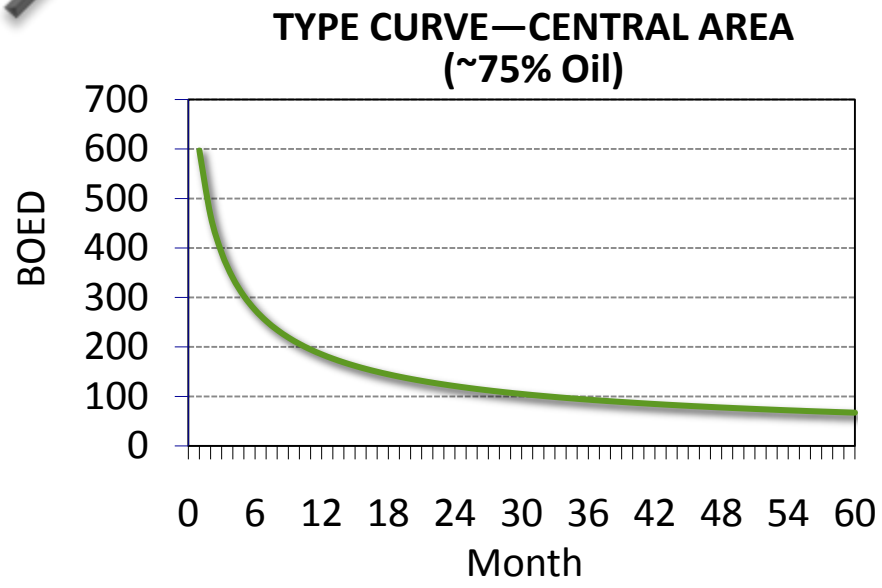
[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

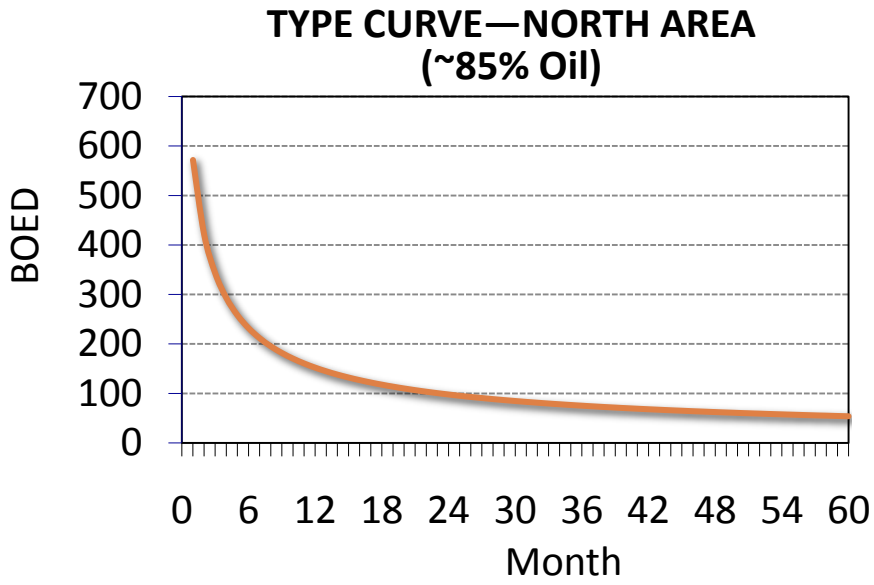
Eagle Ford Economics

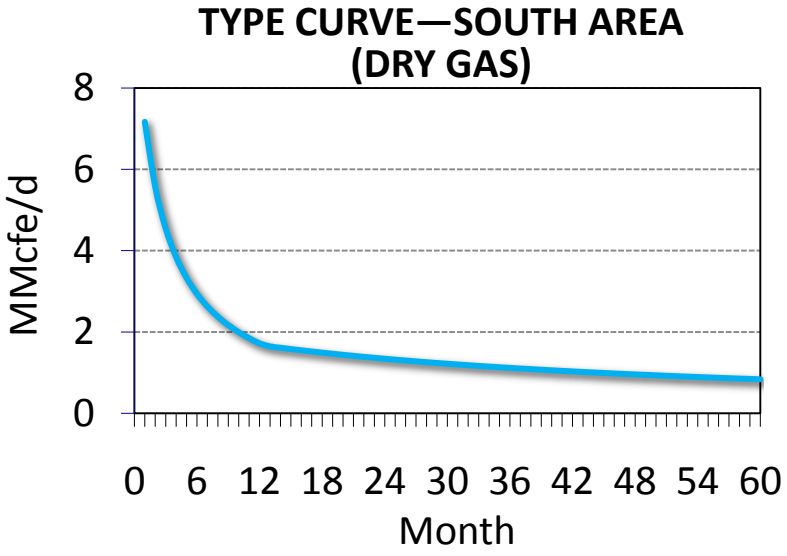
	NORTHERN ACREAGE (Oil)	CENTRAL ACREAGE (Oil)	SOUTHERN ACREAGE (Dry Gas)
Overview			
Objective	Eagle Ford Shale	Eagle Ford Shale	Eagle Ford Shale
Depth	6,000'–7,000'	7,000'–10,000'	9,000'–14,000'
Lateral Length:	4,500'–5,500'	4,500'–5,500'	4,500'–5,500'
Capital costs:	$5.0–$7.5 MM	$7.0–$9.0 MM	$7.0–$12.0 MM
EUR (Gross):	400–550 MBOE	400–900 MBOE	4.0–8.0 Bcfe
Initial prod:	400–800 BOED	600–1,100 BOED	5–15 MMcfe/d
IP (30):	300–600 BOED	400–900 BOED	4–12 MMcfe/d
Metrics ($4.00/MMBtu, $80/Bbl)			
IRR:	25%–45%	25%–>50%	0%–15%
PVR:	1.20–1.40	1.20–1.50	0.85–1.0
F&D costs:	$14–$22 ($/BOE)	$12–$20 ($/BOE)	$1.50–$3.50 ($/Mcfe)

Note: Capital, Production and EUR are gross numbers and do not account for royalties

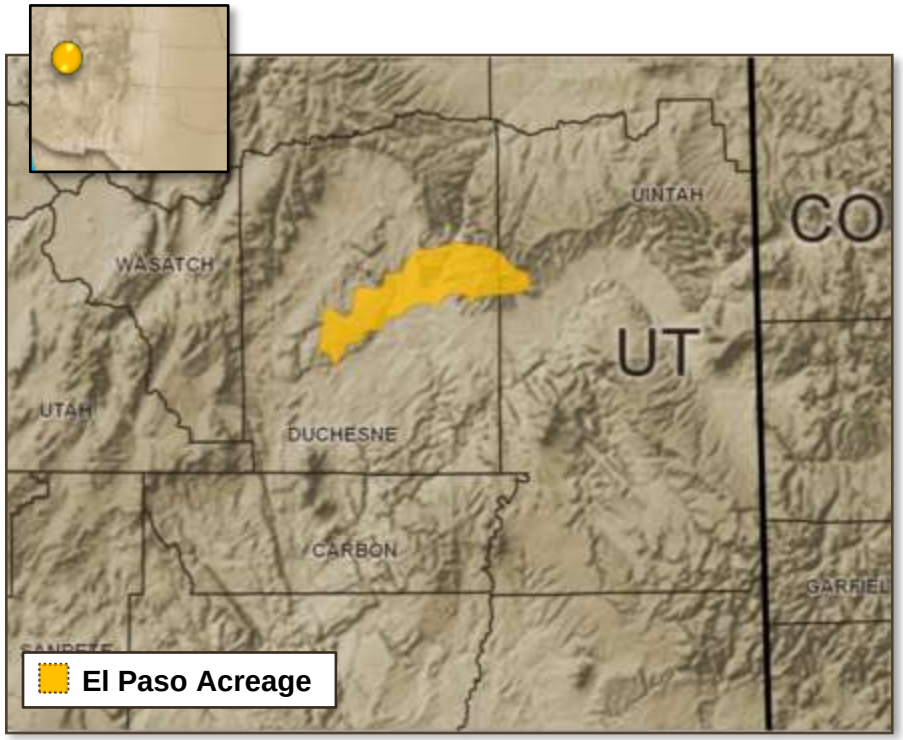
Eagle Ford Decline Profiles







Altamont



190,000 net acres

Program Statistics

- Operated producing wells[1]: 256
- Average WI[2]: 70 %
- Average NRI[2]: 55 %
- Future drilling locations[3]: 840
  - Operated: 740
- PUD reserves : 55 MMBOE
- Unrisked resource potential[3]: 130 MMBOE
- Risked resource potential[3]: 125 MMBOE
- Spacing: 160 acre

[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

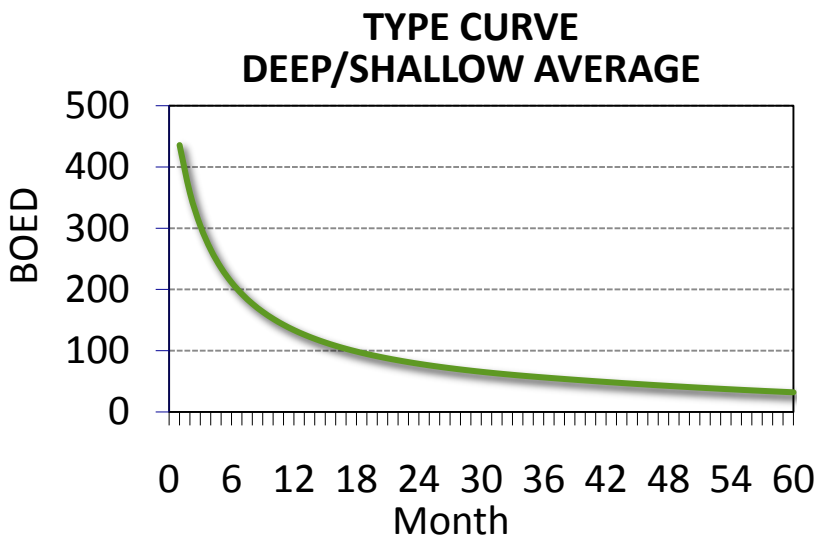
Altamont Economics

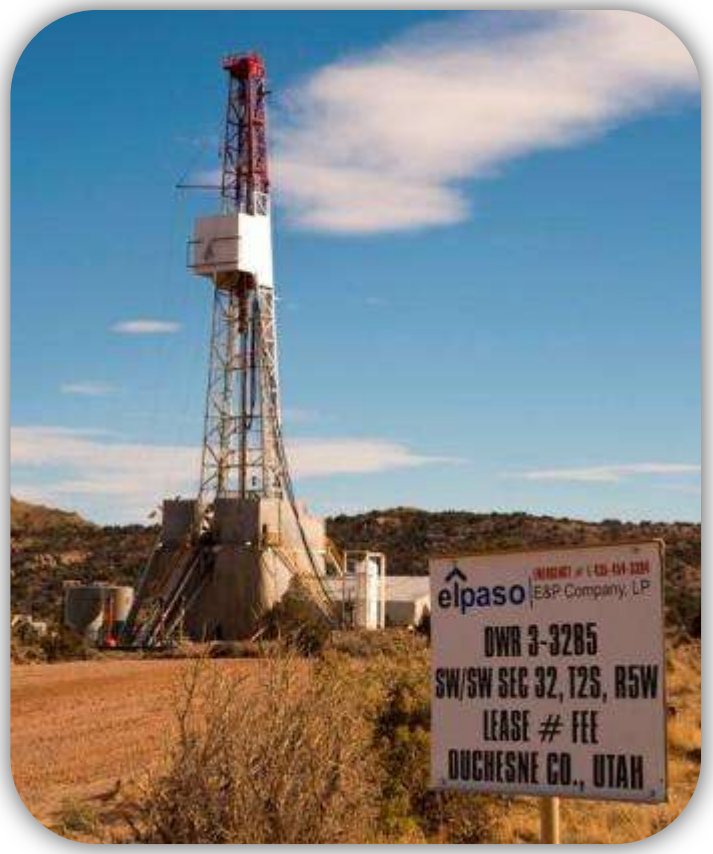
OVERVIEW

• Objective:	Wasatch Green River
• Depth:	9,000'–16,500'
• Capital costs:	$4.0–$7.0 MM
• EUR (Gross):	300–400 MBOE
• Initial prod:	400–600 BOED
• IP(30):	330–500 BOED

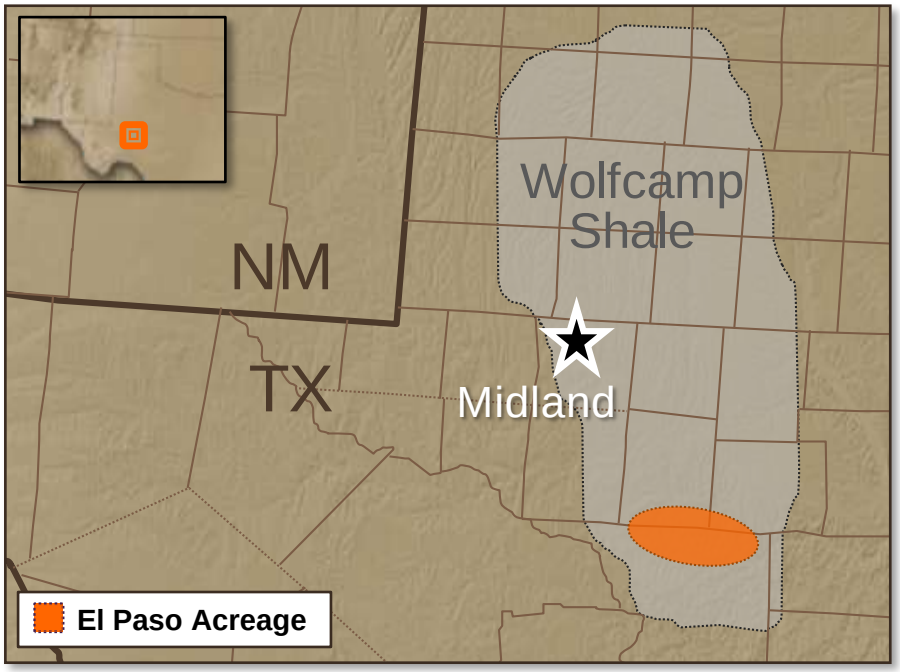
METRICS ($80/Bbl)

• IRR:	25%–45%
• PVR:	1.25–1.45
• F&D costs:	$17–$21/Bbl





Wolfcamp



138,000 net acres

PROGRAM STATISTICS

- Operated producing wells[1]: 0
- Average WI[2]: 100 %
- Average NRI[2]: 75 %
- Future drilling locations[3]: 860
  - 100% operated
- PUD reserves: 6 MMBOE
- Unrisked resource potential[3,4]: 220 MMBOE
- Risked resource potential[3,4]: 155 MMBOE
- Spacing: 160 acre current

[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations
[4]Risked and unrisked resource potential only includes upper Wolfcamp

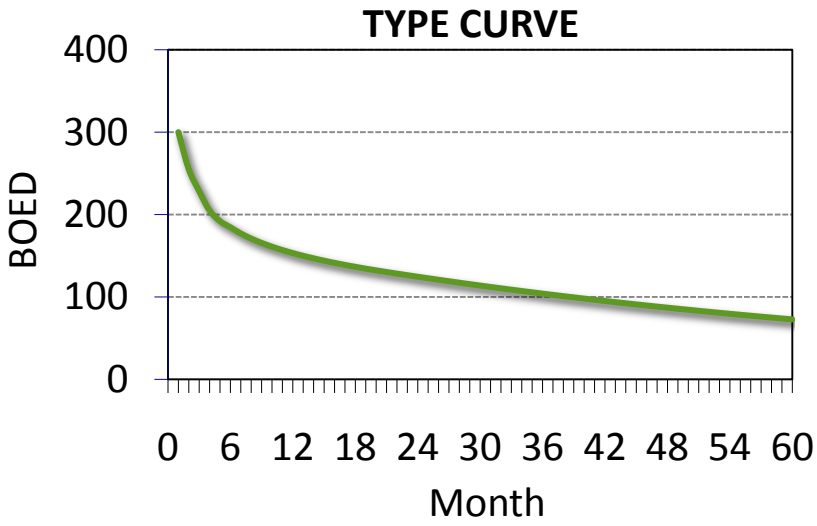
Wolfcamp Economics

OVERVIEW

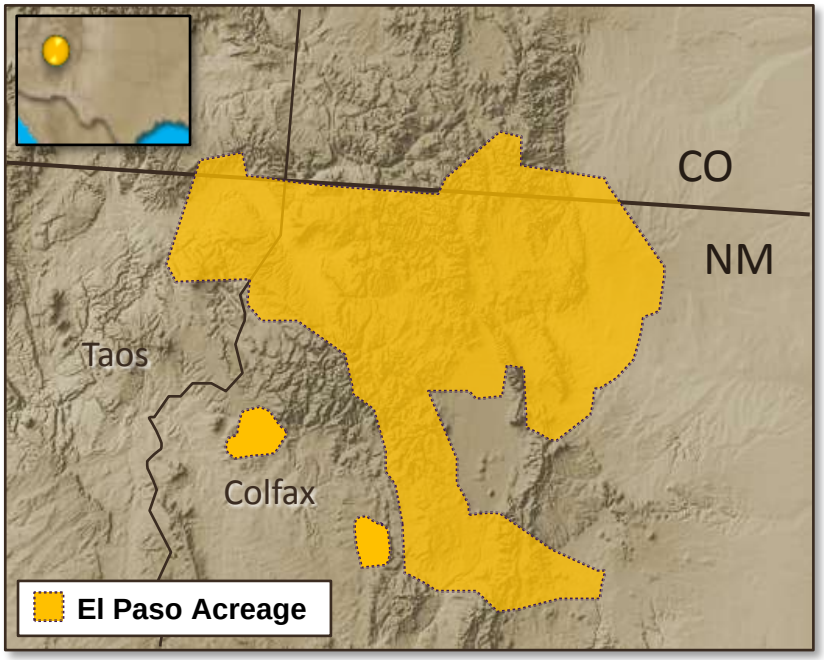
- Objective: Upper Wolfcamp Shale
- Depth: 5,000'–8,000'
- Lateral Length: 4,000'–6,000'
- Capital costs: $4.0–$6.0 MM
- EUR (Gross): 300–380 MBOE
- Initial prod: 300–400 BOE/d
- IP(30): 250–350 BOE/d

METRICS ($80/Bbl)

- IRR: 25%–35%
- PVR: 1.25–1.35
- F&D costs: $17–$25/Bbl



Raton



El Paso owns 605,000 acres of minerals

PROGRAM STATISTICS

- Operated producing wells[1]: 943
- Average WI[2]: 100 %
- Average NRI[2]: 93 %
- Future drilling locations[3]: 840
  - 100% Operated
- PUD reserves : 190 Bcfe
- Unrisked resource potential[3]: 350 Bcfe
- Risked resource potential[3]: 325 Bcfe
- Spacing:

  160 acre initial / 80 acre down-spacing

[1]As of 12/31/10
[2]Average working interest and net revenue interest for operated wells only
[3]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

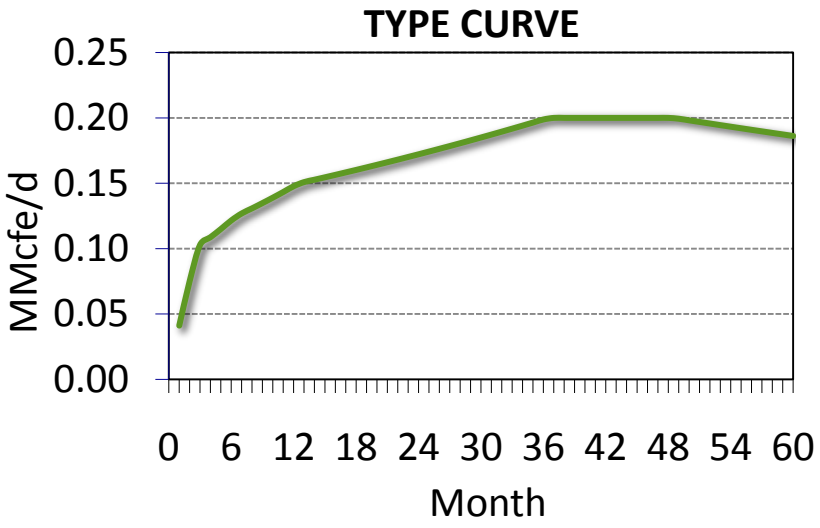
Raton Economics

OVERVIEW

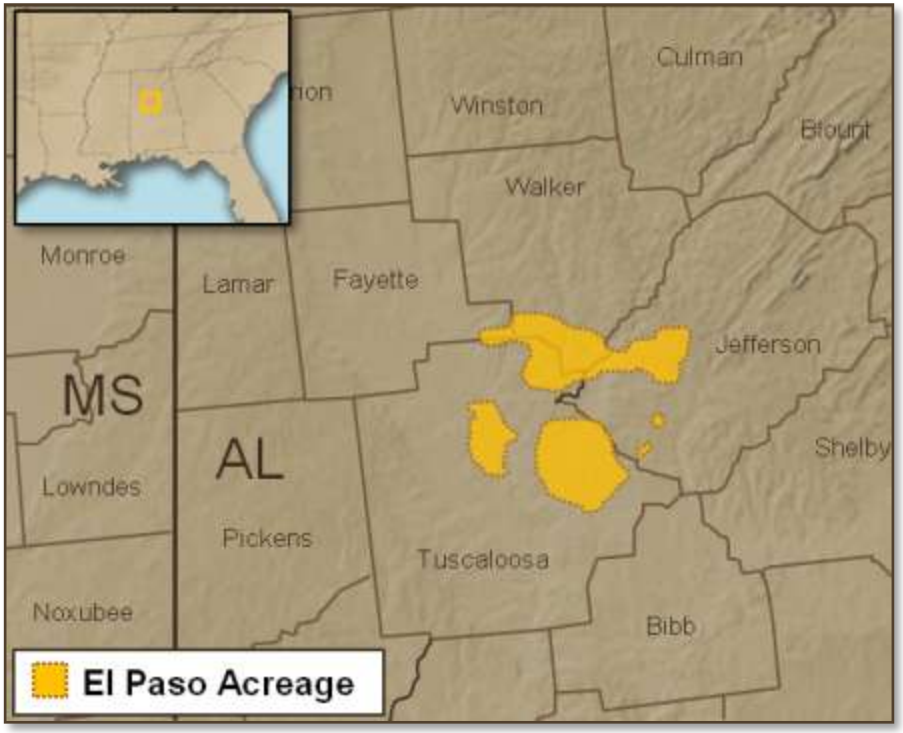
- Objective: Raton CBM
- Depth: 2,500'
- Capital costs: $400K–$600K
- EUR (Gross): 1.0–1.3 Bcfe
- Initial prod: 30–50 Mcfe/d
- IP(30): 30–50 Mcfe/d

METRICS ($4.00/MMBtu)

- IRR: 20% – 30%
- PVR: 1.40 – 1.50
- F&D costs: $0.30–$0.60/Mcfe



Black Warrior



110,000 net acres

PROGRAM STATISTICS

- Operated producing wells: 1,171
- Average WI[1]: 86 %
- Average NRI[1]: 69 %
- Future drilling locations[2]: 270
  - 100% Operated
- PUD reserves : 25 Bcfe
- Unrisked resource potential[2]: 60 Bcfe
- Risked resource potential[2]: 60 Bcfe
- Spacing:

  160 acre initial / 80 acre down-spacing

[1]Average working interest and net revenue interest for operated wells only
[2]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

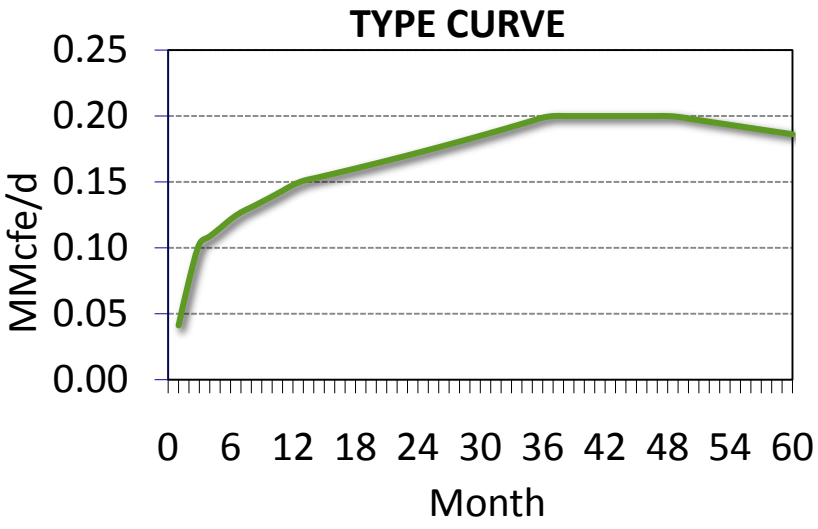
Black Warrior Basin Economics

OVERVIEW

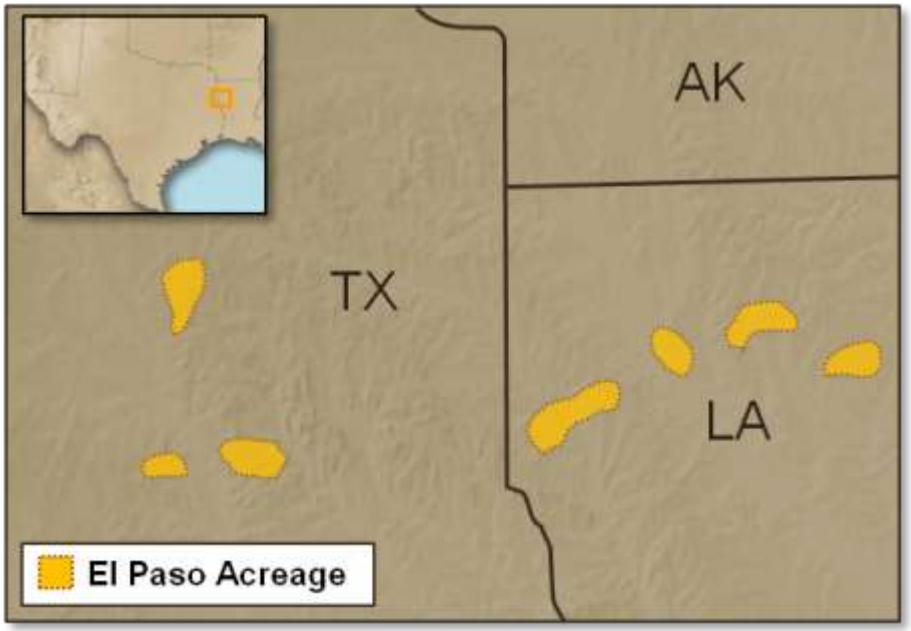
- Objective: Black Warrior CBM
- Depth: 700’ – 2,500'
- Capital costs: $350K – $400K
- EUR (Gross): 0.3 – 0.6 Bcf
- Initial prod: 30–50 Mcf/d
- IP(30): 40–60 Mcf/d

METRICS ($4.00/MMbtu)

- IRR: 5%–15%
- PVR: 0.75–1.1
- F&D costs: $1.00 – $1.65/Mcfe



East TX & North LA (w/o Haynesville)



117,000 net acres[3]

PROGRAM STATISTICS

- Operated producing wells: 1,134
- Average WI[1]: 81 %
- Average NRI[1]: 66 %
- Future drilling locations[2]: 575
  - 100% Operated
- PUD reserves: 85 Bcfe
- Unrisked resource potential[2]: 410 Bcfe
- Risked resource potential[2]: 410 Bcfe
- Spacing: 160 acre

[1]Average working interest and net revenue interest for operated wells only
[2]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations
[3]Inclusive of Haynesville acreage

Gulf of Mexico

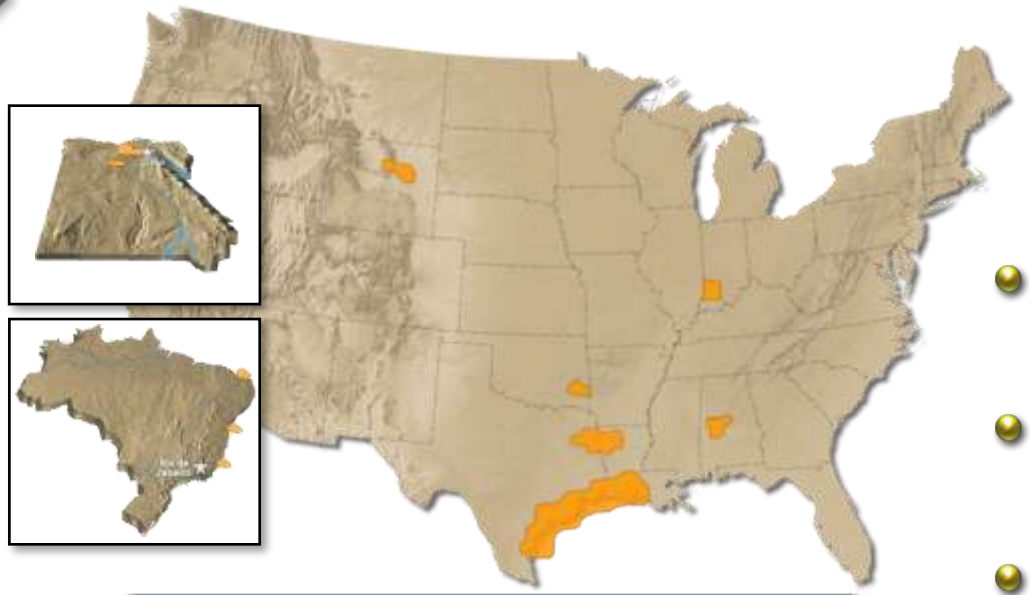
63 blocks

PROGRAM STATISTICS

- Operating wells: 42
- Average WI[1]: 65 %
- Average NRI[1]: 48 %
- Future drilling locations[2]: 65
  - Operated: 64
- PUD reserves : 0 Bcfe
- Unrisked resource potential[2]: 895 Bcfe
- Risked resource potential[2]: 505 Bcfe

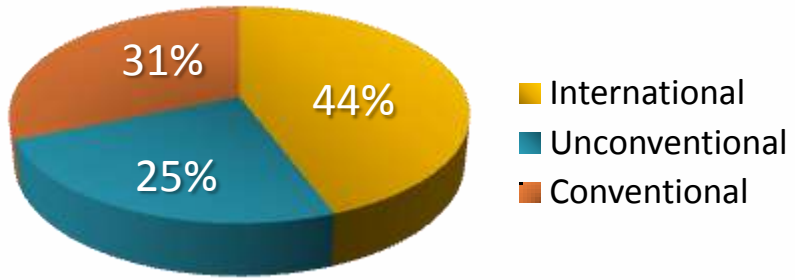
[1]Average working interest and net revenue interest for operated wells only
[2]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

Other Assets



- Undrilled Locations[1]: 2,010
- PUD Reserves: 75 Bcfe
- Unrisked Resource Potential[1]: 3,830 Bcfe
- Risked Resource Potential[1]: 1,795 Bcfe

NET RISKED RESOURCE POTENTIAL
(1.8 Tcfe)



[1]Future locations and resource potential as of 12/31/10, future locations shown on an unrisked basis and include PUD locations

PVR (Present Value Ratio)

- Present Value Ratio =

  (Total Capital + NPV)/Total Capital

- NPV & total capital discounted at 12%
- Minimum ratio is 1.15: Every $1.00 invested returns $1.15 on an after-tax, discounted basis over the life of the project
- Total capital includes drilling, completion, & wellhead facility costs. Does not include sunk costs or infrastructure

Reserve Metrics

We calculate two primary metrics, (i) a reserve replacement ratio and (ii) reserve replacement costs, to measure our ability to establish a long-term trend of adding reserves at a reasonable cost in our core asset areas. The reserve replacement ratio is an indicator of our ability to replenish annual production volumes and grow our reserves. It is important for us to economically find and develop new reserves that will more than offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves. In addition, we calculate reserve replacement costs to assess the cost of adding reserves which is ultimately included in depreciation, depletion and amortization expense. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our asset areas at lower costs than our competition. We calculate these metrics as follows:

Reserve replacement ratio $= \dfrac{\text{Sum of reserve additions}^{1}}{\text{Actual production for the corresponding period}}$

Reserve replacement costs/Mcfe $= \dfrac{\text{Total oil and gas capital costs}^{2}}{\text{Sum of reserve additions}^{1}}$

We show the calculation of domestic reserve replacement costs excluding the impact of acquisitions, performance and price-related revisions on reserves to demonstrate the effectiveness of our domestic drilling program exclusive of economic factors (such as price) outside of our control.

The reserve replacement ratio and reserve replacement costs per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

The exploration for and the acquisition and development of natural gas and oil reserves is inherently uncertain as further discussed in the Company's SEC filings. One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped.

[1]Reserve additions include proved reserves and reflect reserve revisions for prices and performance, extensions, discoveries and other additions and acquisitions and do not include unproved reserve quantities or proved reserve additions attributable to investments accounted for using the equity method. All amounts except for 2011 estimates are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations in the company's 2010 Annual Report on Form 10-K.

[2]Total oil and gas capital costs include the costs of development, exploration and proved property acquisition activities conducted to add reserves and exclude asset retirement obligations. All amounts except for 2011 estimates are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations in the company's 2010 Annual Report on Form 10-K.

Unproved Resources

- Unconventional: Unconventional resources primarily consist of the company's Haynesville, Eagle Ford, and Wolfcamp shale plays and coal bed methane operations in the Raton, Black Warrior and Arkoma Basins.
- Conventional, low-risk: This consists of conventional resources in the Altamont Field, other Rockies programs, south Texas, and Brazil development programs. It also includes tight-sand drilling in the ArkLaTex area.
- Conventional, higher-risk: This includes higher-risk exploration in the Gulf of Mexico, Texas Gulf Coast, and undrilled international exploration prospects in Brazil and Egypt.