Approach Resources Inc.

Canaccord Genuity 5th Annual Global Energy Conference

OCTOBER 12-13, 2011

Forward-looking statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of management regarding plans, strategies, objectives, anticipated financial and operating results of the Company, including as to the Company's Wolffork shale resource play, estimated oil and gas in place and recoverability of the oil and gas, estimated reserves and drilling locations, capital expenditures, typical well results and well profiles, and production and operating expenses guidance included in the presentation. These statements are based on certain assumptions made by the Company based on management's experience and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and believed to be reasonable by management. When used in this presentation, the words "will," "potential," "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," "target," "profile," "model," or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. In particular, careful consideration should be given to the cautionary statements and risk factors described in the Company's Annual Report on Form 10-K for the year ended December 31, 2010. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Cautionary statements regarding oil and gas quantities

The Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses the terms "estimated ultimate recovery" or "EUR," reserve or resource "potential," "upside," "oil and gas in place" or "OGIP," "OIP" or "GIP," and other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's rules may prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized by the Company.

EUR estimates, potential drilling locations, resource potential and OGIP estimates have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from our estimates. There is no commitment by the Company to drill all of the drilling locations that have been attributed these quantities. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves, type/decline curves, per well EUR, OGIP and resource potential may change significantly as development of the Company's oil and gas assets provides additional data.

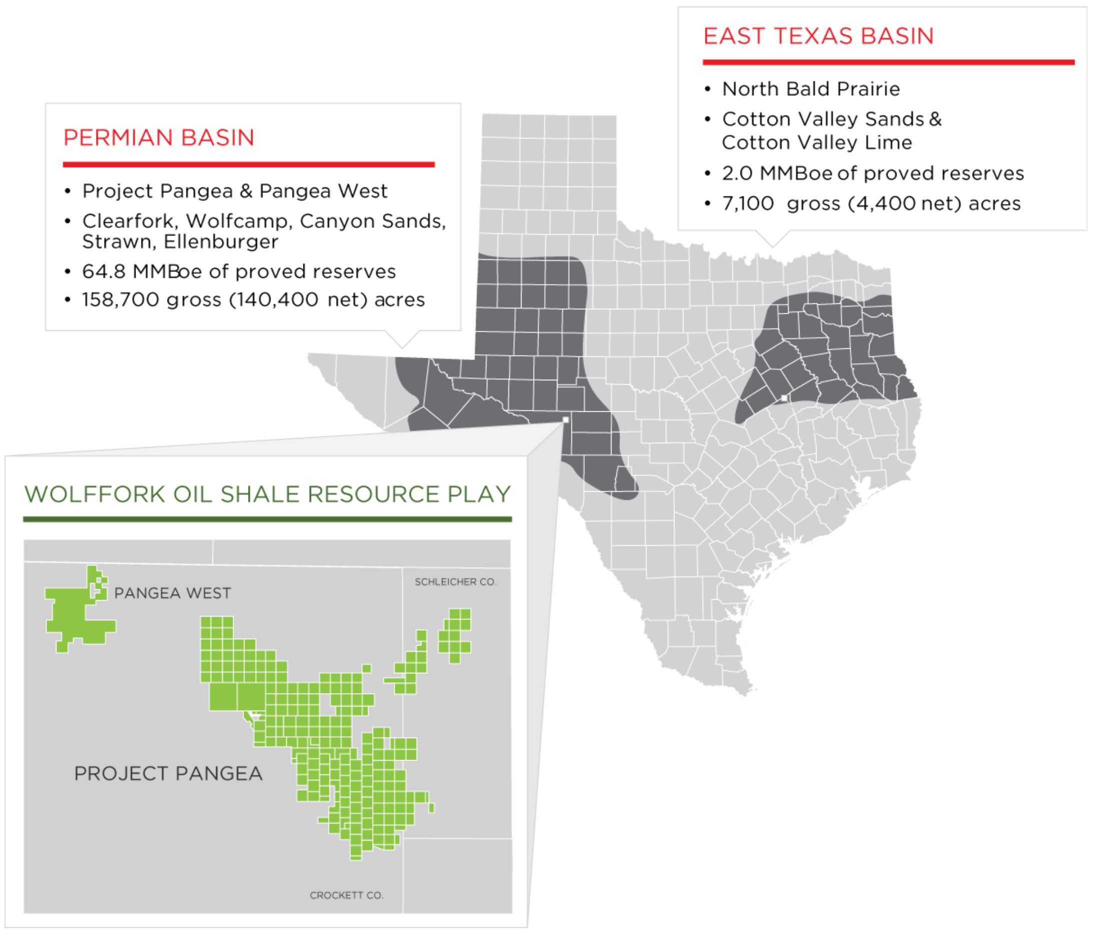
Type/decline curves, estimated EURs, typical well related oil and gas in place, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, OGIP, recovery factors and costs prove correct. The Company has very limited production experience with these projects, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential, EURs and OGIP do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. IRR estimates assume NYMEX forward-curve gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or G&A costs.

Approach Resources Inc.

AREX OVERVIEW

- Enterprise value $614.7 MM
- High quality reserve base
  - 66.8 MMBoe proved reserves
    - 97% Permian Basin
    - 55% Oil & NGLs
- Permian core operating area
  - 158,700 gross (140,400 net) acres
  - 500+ MMBoe gross, unrisked resource potential
  - Extensive inventory of drilling and recompletion opportunities
- Strong balance sheet to execute plan
  - Borrowing base increased to $260 MM from $200 MM

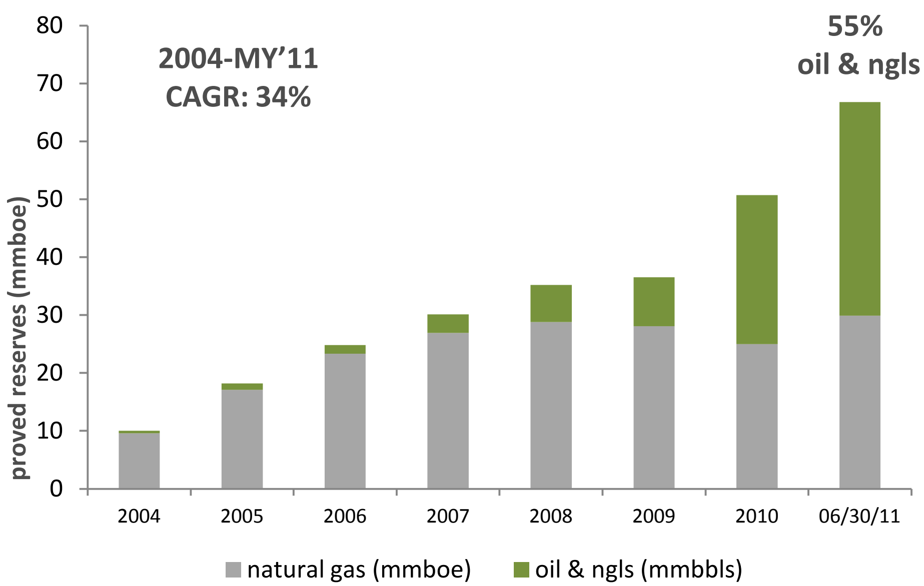
ASSET OVERVIEW



Notes: Proved reserves and acreage as of 6/30/2011. All Boe and Mcfe calculations are based on a 6 to 1 conversion ratio. Enterprise value is equal to market capitalization using the closing price of $18.35 per share on 10/7/2011, plus net debt as of 6/30/2011.

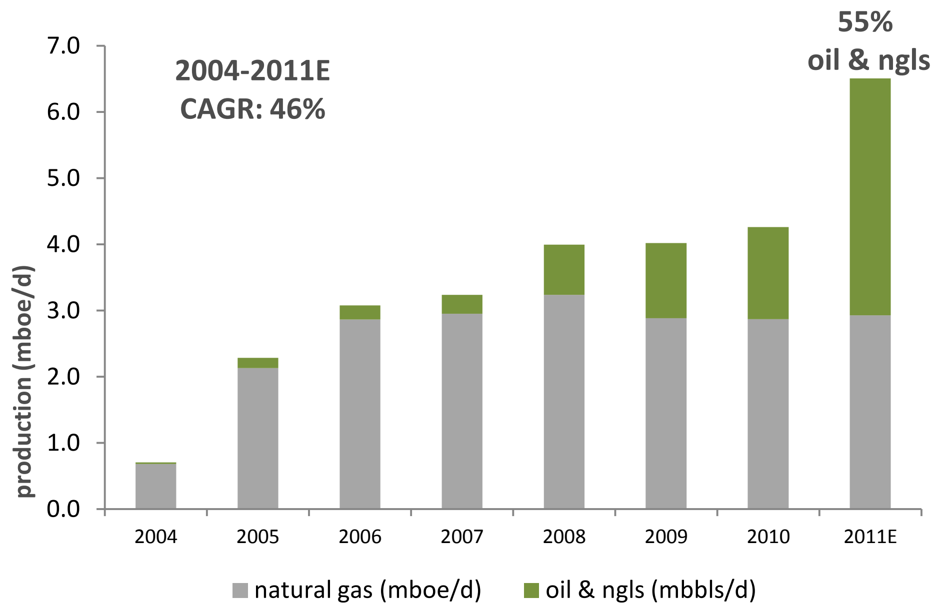
Track Record of Reserve and Production Growth

RESERVE GROWTH



- MY'11 proved reserves up 32% to 66.8 MMBoe
  - Oil & NGL reserves up 44% to 36.9 MMBbls
- Replaced 1,598% of reserves during 1H'11 at an all-in F&D cost of $9.45/Boe
- 8.4 MMBoe proved reserves booked to Wolffork oil shale resource play

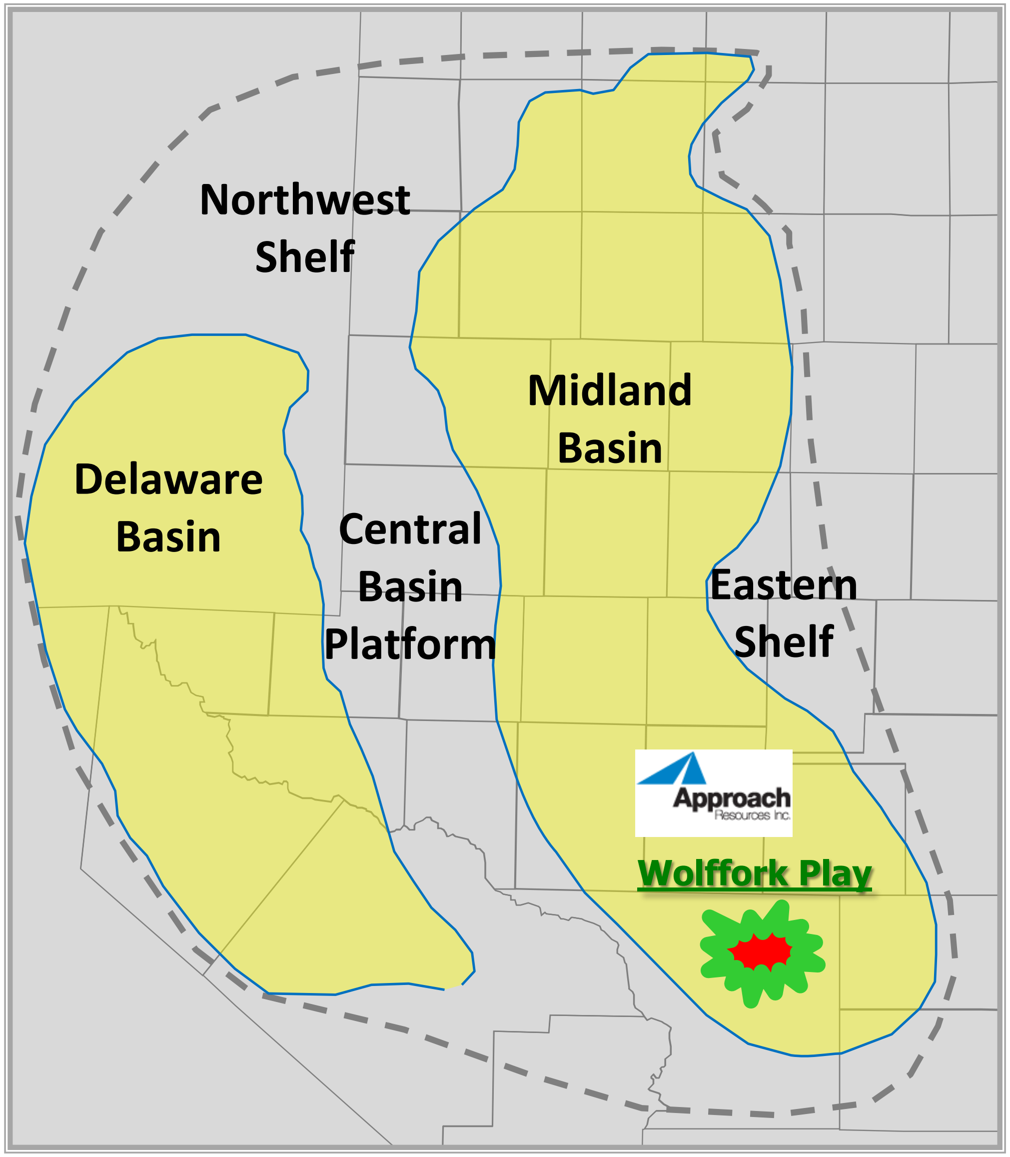
PRODUCTION GROWTH



- Balanced production mix in 2011 and beyond
- 98% Permian Basin
- 2011 targets:
  - 50%+ Production growth
  - 55% Oil and NGLs; 45% natural gas production mix

Note: 2011E production and production mix based on the midpoint of production guidance. See "F&D Costs Reconciliation" slide in appendix for reconciliation.

Permian Basin – World Class Petroleum Basin

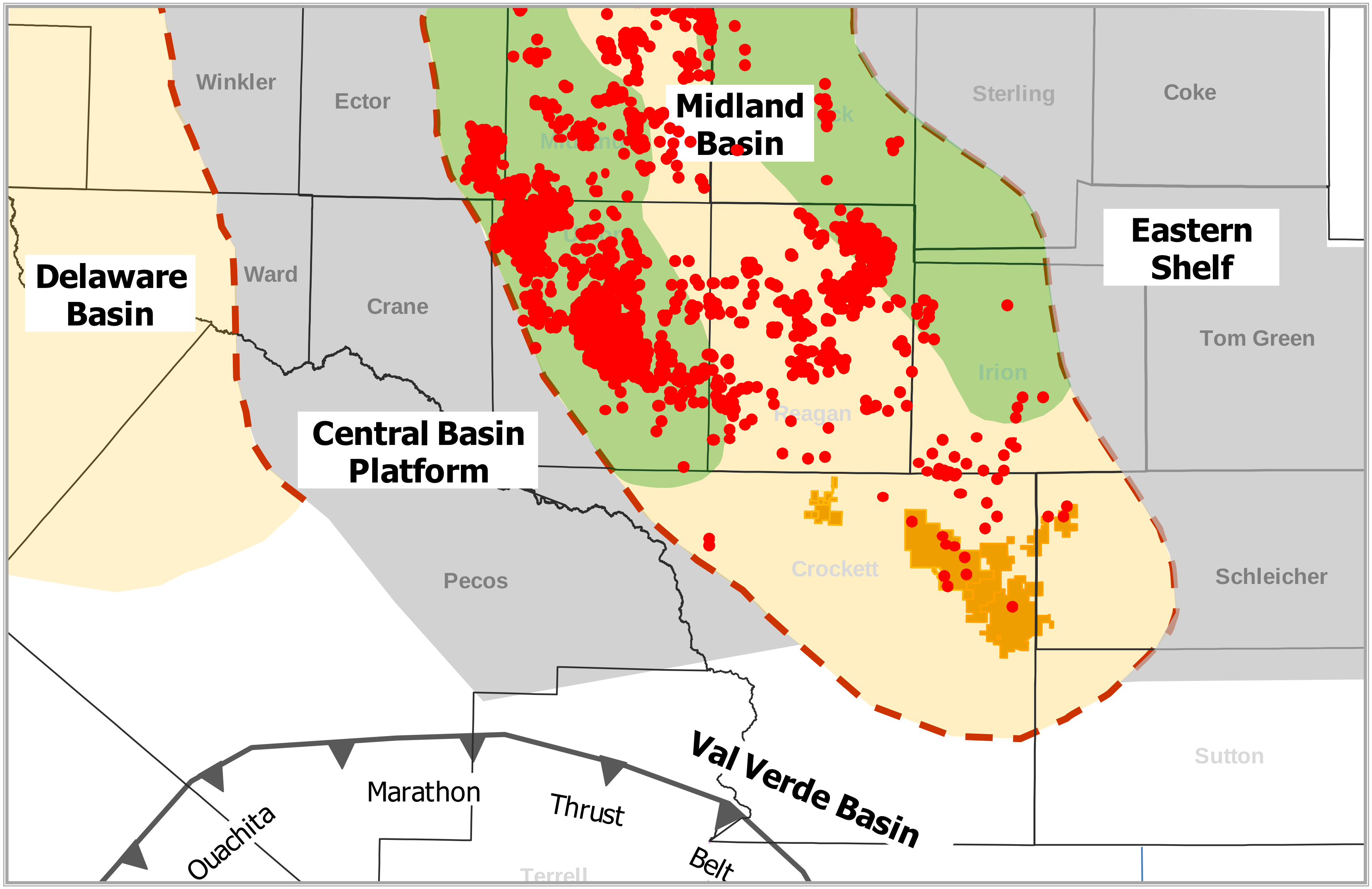


PERMIAN BASIN

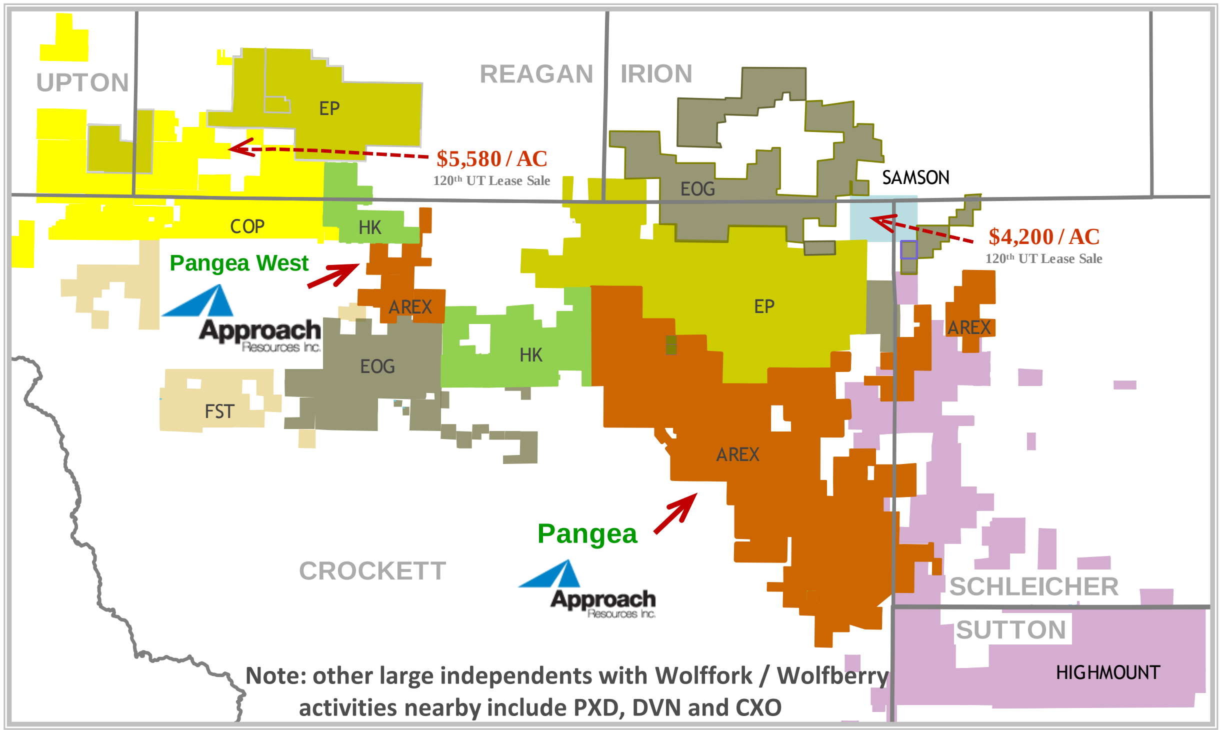
- 250 miles by 300 miles
- 1st commercial oil accumulation (Westbrook) discovered in 1921
- Over 30 billion barrels of oil produced over last 90 years
- Largest oil and gas producing area in Lower 48
- Over 1,300 oil reservoirs and 30 plays identified
- Approximately 80% of producing reservoirs <10,000’
- Over 450 US rigs are active in Permian

Source: USGS, Bureau of Economic Geology, Baker Hughes and IHS.

AREX Acreage Position – Favorably Located in the Permian Basin



AREX Acreage Position – Permian Basin



- **Large, primarily contiguous acreage position**
  - 158,700 gross (140,400 net) acres (~76% NRI)
  - Low acreage cost ~$350 per acre
- **Low-risk, long-life reserve base**
  - 64.8 MMBoe proved reserves
  - 57% liquids (51% proved developed)
- **Significant potential reserves**
  - 500+ MMBoe gross, unrisked reserve potential
  - 2,900+ potential horizontal, vertical and recompletion targets
  - Additional upside potential in downspacing opportunities
- **2011 Program – $130 MM**
  - 2 vertical rigs and 1 horizontal rig
  - De-risk acreage position with horizontal and vertical pilot program
  - Acquire 3-D seismic data

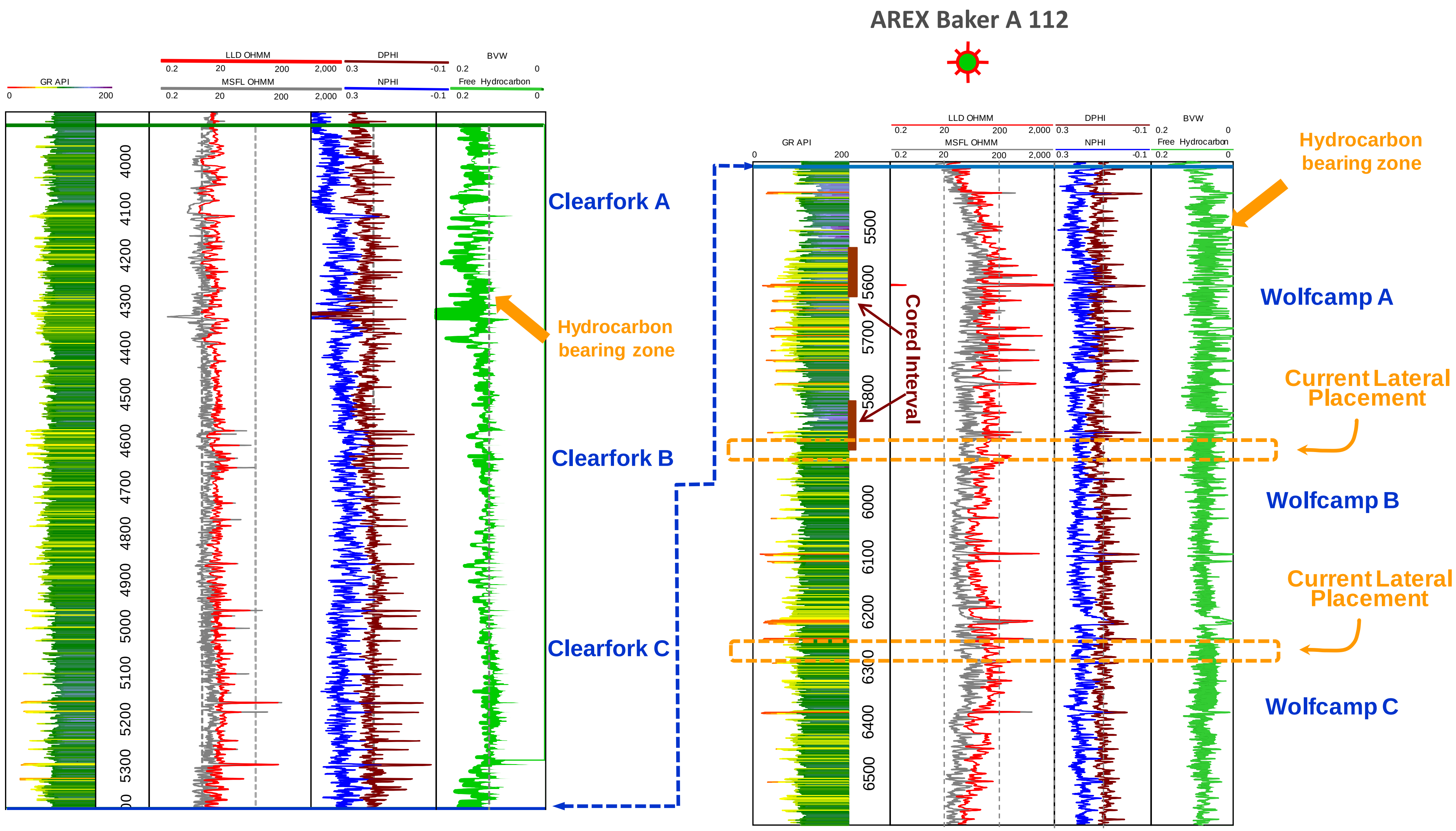
Wolfcamp Shale Name Convention – Southern Midland Basin

System	Stratigraphic Unit
Permian	**Clearfork / Spraberry**
	Dean
	Wolfcamp
Pennsylvania	Canyon
	Strawn
Mississippian	
Devonian	
Silurian	
Ordovician	Ellenburger

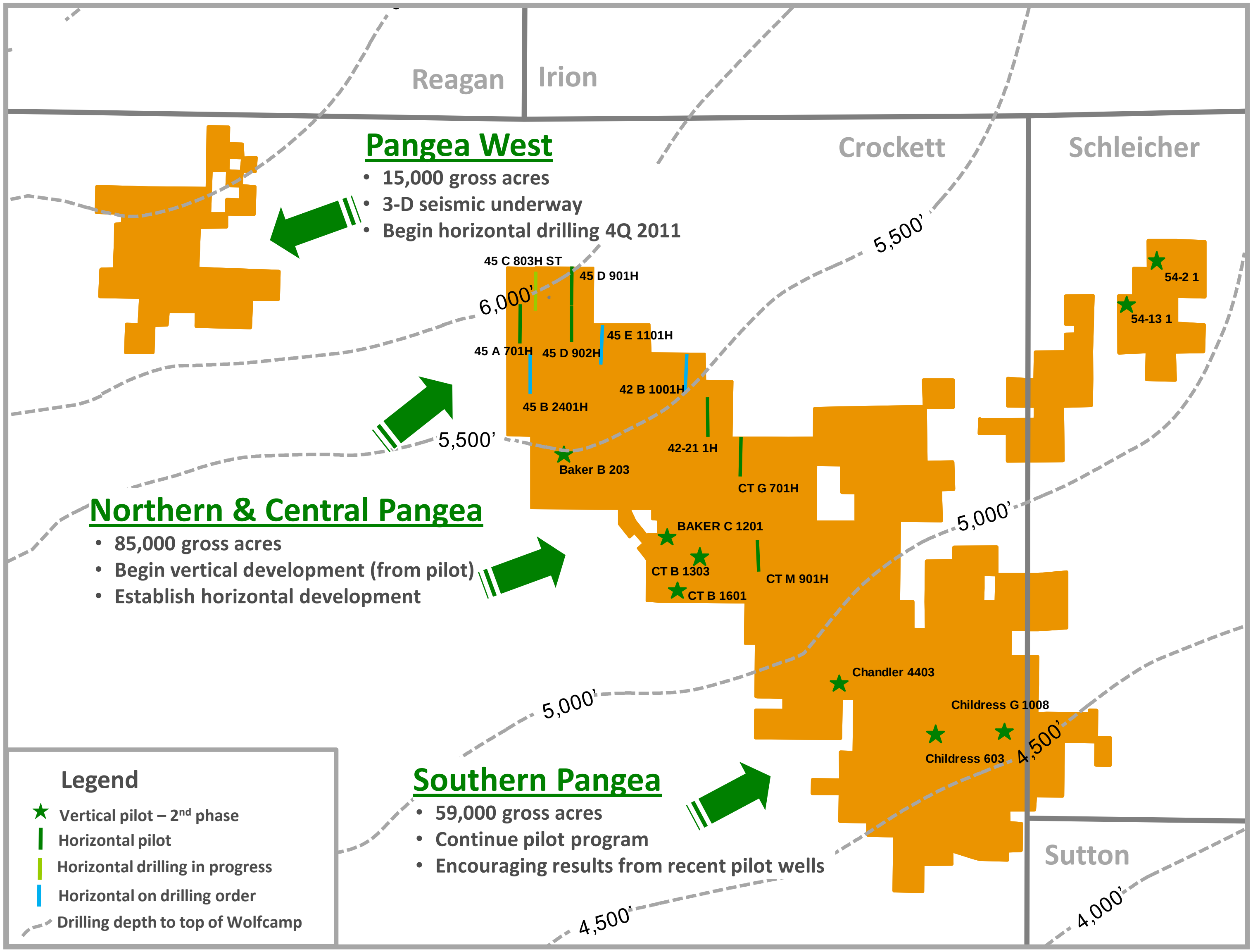
AREX (10/18/2010)	EP (5/24/2011)		PXD (9/7/2011)
Wolfcamp A	Wolfcamp A	Upper Wolfcamp	Leonard Shale
			Upper Wolfcamp
Wolfcamp B	Wolfcamp B		Tippett Shale
			Middle Wolfcamp
Wolfcamp C	Wolfcamp C	Lower Wolfcamp	Wolfcamp Shale
Wolfcamp D	Wolfcamp D		Lower Wolfcamp

Wolfcamp shale name conventions are based on investor presentations of AREX (10/18/2010), EP (5/24/2011) and PXD (9/7/2011).

Wolffork Hydrocarbon Column – Over 2,500' Thick



Wolffork Oil Shale Resource Play



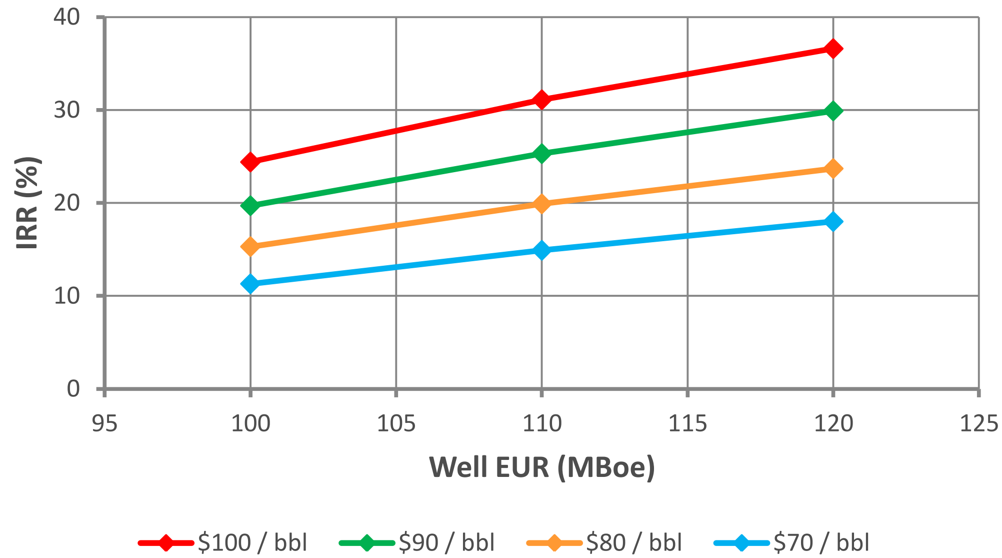
Vertical Wolffork Economics

VERTICAL WOLFFORK

Play Type	Wolffork
Avg. EUR	110 MBoe
Avg. Well Cost	$1.2 MM
F&D	$10.91/Boe
Potential Locations	1,825
Gross Resource Potential	**200+ MMBoe**

- Target Clearfork and Wolfcamp zones
- Drilling depth < 7,000’
- ~75% of EUR comprised of oil and NGLs
- Beginning vertical Wolffork development program
- 1 active rig in NE Pangea

BTAX IRR SENSITIVITIES



Note: Potential locations based on 20 acre spacing. Economics assume NYMEX gas strip 7/2011 and NGL price based on 50% of oil WTI price.

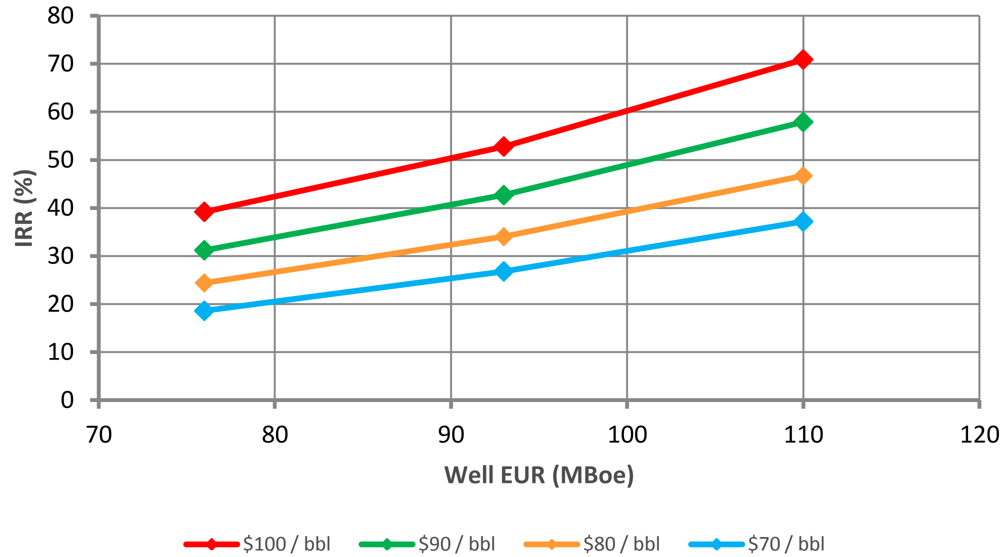
Vertical Wolffork Recompletion Economics

VERTICAL WOLFFORK RECOMPLETIONS

Play Type	Wolffork Recompletions
Avg. EUR	93 MBoe
Avg. Well Cost	$750 M
F&D	$8.06/Boe
Potential Locations	190
Gross Resource Potential	**17+ MMBoe**

- Target Clearfork and Wolfcamp zones
- Commingle with existing production
- ~75% of EUR comprised of oil and NGLs
- Increasing recompletions to 4 per month beginning October 2011

BTAX IRR SENSITIVITIES



Note: Potential locations based on 20 to 40 acre spacing. Economics assume NYMEX gas strip 7/2011 and NGL price based on 50% of oil WTI price.

Vertical Wolffork Well Profile

Type/decline curves, estimated EURs, typical well related oil and gas in place, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, OGIP, recovery factors and costs prove correct. The Company has very limited production experience with these projects, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential, EURs and OGIP do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. IRR estimates assume NYMEX forward-curve gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or G&A costs.

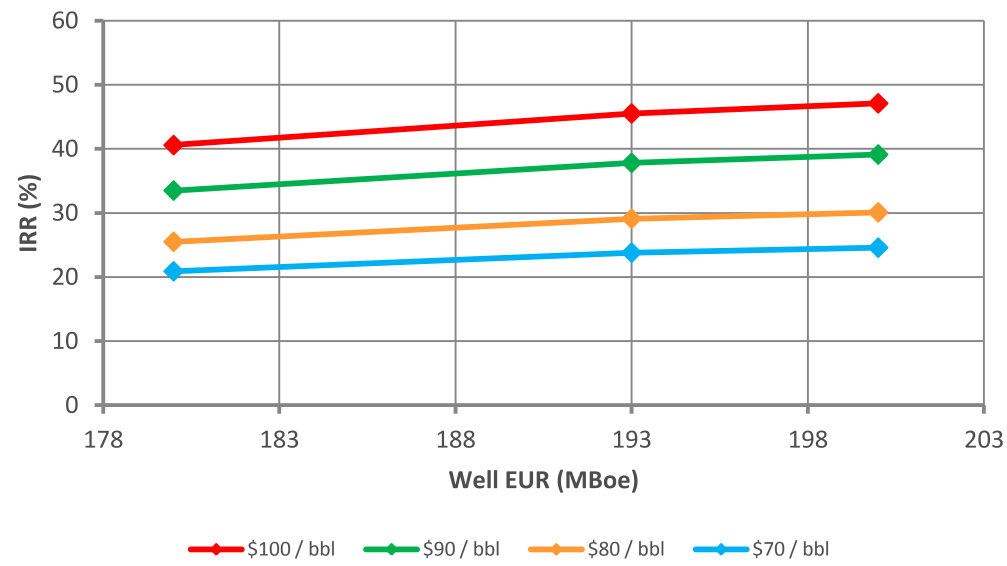
Vertical Canyon Wolffork Economics

VERTICAL CANYON WOLFFORK

Play Type	Canyon Wolffork
Avg. EUR	193 MBoe
Avg. Well Cost	$1.5 MM
F&D	$7.77/Boe
Potential Locations	440
Gross Resource Potential	**85 MMBoe**

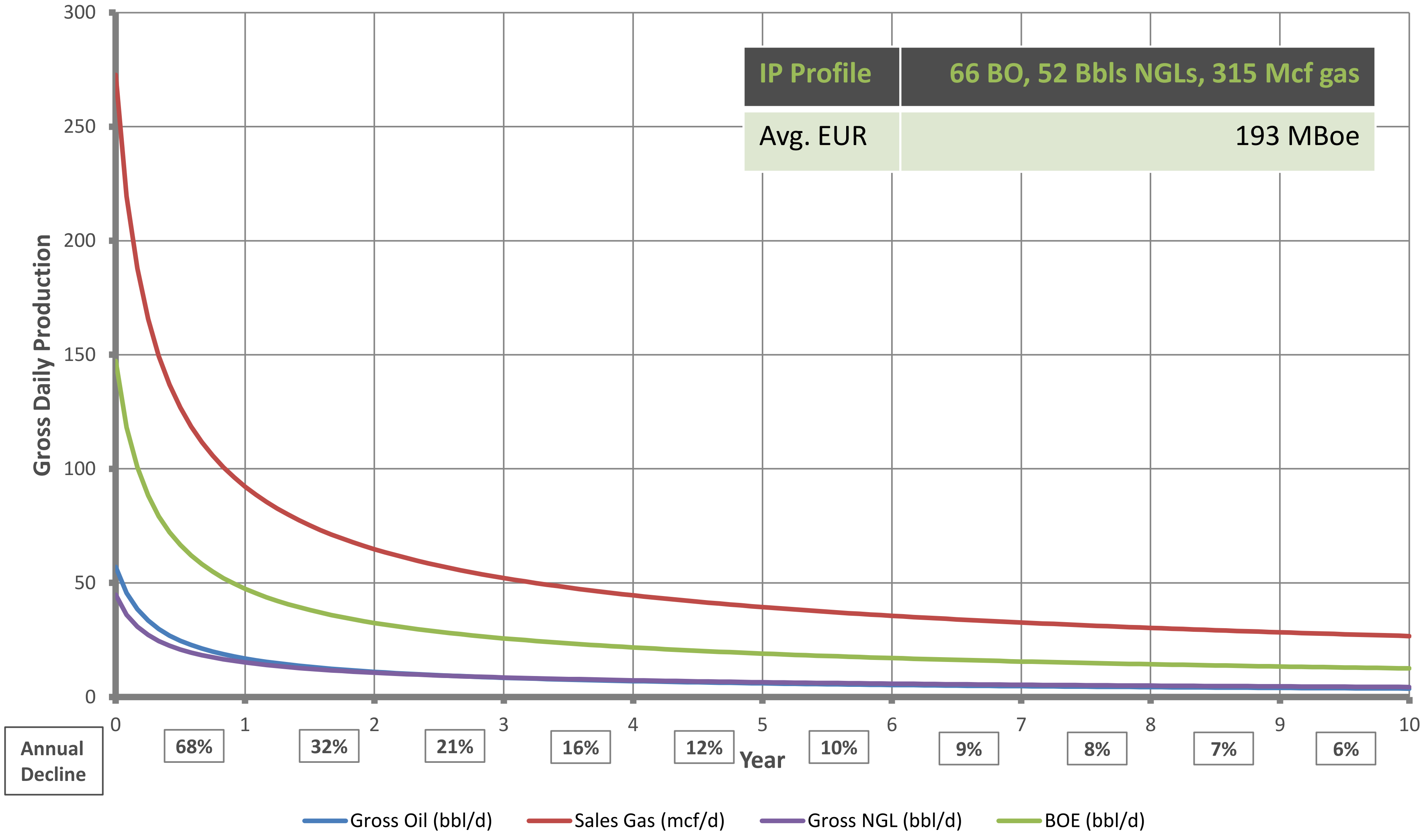
- 1 active rig in Pangea

BTAX IRR SENSITIVITIES



Note: Potential locations based on 40 acre spacing. Economics assume NYMEX gas strip 7/2011 and NGL price based on 50% of oil WTI price.

Vertical Canyon Wolffork Well Profile



Type/decline curves, estimated EURs, typical well related oil and gas in place, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, OGIP, recovery factors and costs prove correct. The Company has very limited production experience with these projects, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential, EURs and OGIP do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. IRR estimates assume NYMEX forward-curve gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or G&A costs.

Horizontal Wolfcamp – Enhancing Wolfcamp Value

Oil Shale Play	Well EUR (Boe)		Potential Uplift
	Vertical	Horizontal	
Eagle Ford	49,500	323,813	6.5x
Niobrara	40,000	290,000	7.3x
Wolfcamp	80,000	450,000	5.6x

Notes: Eagle Ford and Niobrara well EURs from industry publications. Wolfcamp well EUR is based on AREX estimates.

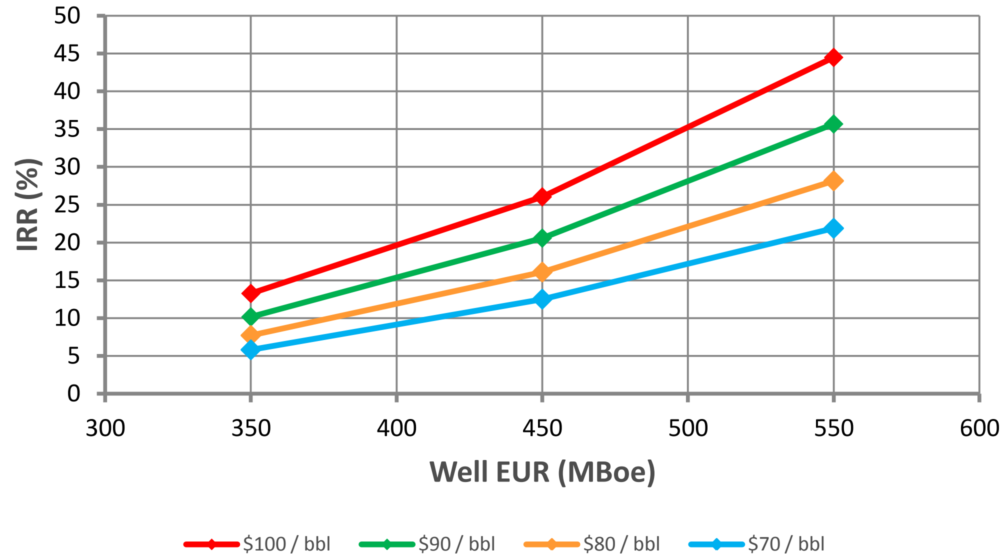
Horizontal Wolfcamp Economics

HORIZONTAL WOLFCAMP

Play Type	Horizontal Wolfcamp
Avg. EUR	450 MBoe
Targeted Well Cost	$5.5 MM
F&D	$12.22/Boe
Potential Locations	500
Gross Resource Potential	**225 MMBoe**

- Horizontal drilling improves recoveries and returns
- Target Wolfcamp zone
- 7,000'+ lateral length, 20+ frac stages
- ~74% of EUR comprised of oil and NGLs
- Recent horizontal pilot results encouraging
- Transitioning to development program – 1 active rig in Pangea

BTAX IRR SENSITIVITIES



- Recent horizontal Wolfcamp well results

University 45 A 701H – 6,859' lateral, 21 frac stages

Initial 24-hour flow rate 693 BOEPD, 94% liquids (613 BO, 41 Bbls NGLs, 237 Mcf gas)

Cinco Terry G 701H – 7,609' lateral, 23 frac stages

Initial 24-hour flow rate 328 BOEPD, 76% liquids (168 BO, 81 Bbls NGLs, 473 Mcf gas)

Note: Potential locations based on 1,000-foot spacing between each horizontal well. Economics assume NYMEX gas strip 7/2011 and NGL price based on 50% of oil WTI price.

Horizontal Wolfcamp Well Profile

IP Profile	230 BO, 47 Bbls NGLs, 285 Mcf gas
Avg. EUR	450 MBoe

Type/decline curves, estimated EURs, typical well related oil and gas in place, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, OGIP, recovery factors and costs prove correct. The Company has very limited production experience with these projects, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential, EURs and OGIP do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. IRR estimates assume NYMEX forward-curve gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or G&A costs.

Summary – AREX Total Resource Potential

Play Type	Locations	Avg. EUR (MBoe)	F&D ($/Boe)	Gross Resource Potential (MMBoe)
Horizontal Wolfcamp	500	450	12.22	225
Vertical Wolffork	1,825	110	10.91	200
Vertical Canyon Wolffork	440	193	7.77	85
Vertical Wolffork Recompletions	190	93	8.06	17
500+ MMBoe Total Gross Resource Potential				

Type/decline curves, estimated EURs, typical well related oil and gas in place, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, OGIP, recovery factors and costs prove correct. The Company has very limited production experience with these projects, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential, EURs and OGIP do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. IRR estimates assume NYMEX forward-curve gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or G&A costs.

Key Takeaways

- **Concentrated geographic footprint focused on West Texas Midland Basin oil/liquids-rich plays**
  - 140,400+ net, primarily contiguous acres, 100% operated
  - More than 525 wells drilled by Approach since 2004, with a 93%+ success rate
  - Established basin infrastructure
- **Strong growth track record at competitive costs**
  - Historical production and reserve growth driven by Canyon Sands liquids-rich gas play
  - Future growth from vertical Wolffork and horizontal Wolfcamp plays
  - Low-cost operator with best-in-class F&D and lifting costs
- **Developing significant resource potential from vertical Wolffork and horizontal Wolfcamp plays**
  - Gross, unrisked resource potential totals more than 500+ MMBoe
  - Additional upside potential from down-spacing opportunities
- **Strong balance sheet to execute development plan**
  - $260 MM borrowing base

Financial Framework

APPROACH RESOURCES

2Q 2011 Highlights

AREX 2Q 2011 SUMMARY

- 7th Consecutive quarter of production growth
  - 2Q'11 production 6.7 MBoe/d
- Proved reserves increase 32% to 66.8 MMBoe
  - Oil & NGL reserves increase 44% to 36.9 MMBbls
  - Reserve mix now 55% oil & NGLs
- Improving well results from horizontal Wolfcamp pilot program
- Horizontal Wolfcamp and vertical Wolffork plays add over 500 MMBoe of gross, unrisked resource potential

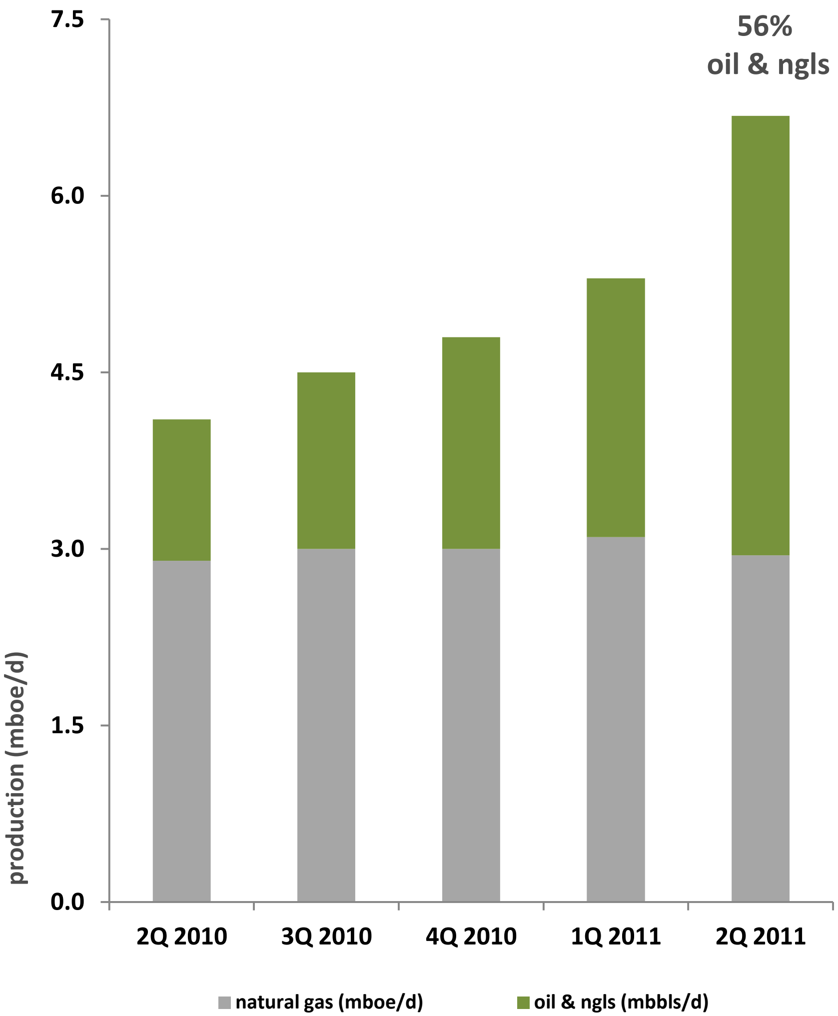
2Q 2011 FINANCIAL HIGHLIGHTS

	Three Months Ended June 30,			
		2011		2010
Revenues ($M)	$	29,123	$	13,155
Net income ($M)	$	7,990	$	1,551
Net income per diluted share	$	0.28	$	0.07
Adjusted net income (non-GAAP) ($M)	$	6,516	$	2,806
Adjusted net income per diluted share	$	0.23	$	0.13
EBITDAX (non-GAAP) ($M)	$	20,999	$	10,345
EBITDAX per diluted share	$	0.73	$	0.49
Realized price ($/Boe)	$	47.90	$	35.36
Production (MBoe/d)		6.7		4.1

Notes: See "Adjusted Net Income" and "EBITDAX" reconciliation slides in appendix for reconciliation of adjusted net income and EBITDAX, respectively. Realized price excludes commodity derivatives.

2Q 2011 Operating Highlights

DELIVERING Q/Q PRODUCTION GROWTH



OPERATING HIGHLIGHTS

- Q2'11 production up 63% to 6.7 MBoe/d
- Oil & NGL production up 203% to 340 MBbls
- Drilled 15 wells, completed 16 wells, and 5 wells waiting on completion
- Horizontal Wolfcamp well results
  - **University 45 A 701H – 6,859' lateral, 21 frac stages**
    - Initial 24-hour flow rate 693 BOEPD, 94% liquids (613 BO, 41 Bbls NGLs, 237 Mcf gas)
  - **Cinco Terry G 701H – 7,609' lateral, 23 frac stages**
    - Initial 24-hour flow rate 328 BOEPD, 76% liquids (168 BO, 81 Bbls NGLs, 473 Mcf gas)

2011 Operating and Financial Guidance

		Current 2011 Guidance
Production		
Total (MBoe)		2,300 – 2,450
Percent Oil & NGLs		55%
Operating costs and expenses ($/per Boe)		
Lease operating	$	4.25 – 5.50
Severance and production taxes	$	2.35 – 3.00
Exploration	$	4.00 – 5.00
General and administrative	$	6.25 – 6.75
Depletion, depreciation and amortization	$	12.00 – 15.00
Capital expenditures ($MM)		Approximately $220

Guidance is forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond the Company's control. See slide 2, "Forward-looking statements," for additional information.

2011 Hedge Position

CURRENT HEDGE POSITION

- **Natural gas (NYMEX – Henry Hub)**
  - 2011 Price swaps contracted for 230,000 MMBtu/month at $4.86/MMBtu
  - June 2011 – December 2011 Price swaps contracted for 200,000 MMBtu/month at $4.74/MMBtu
  - 65% of estimated 2011 natural gas production hedged at weighed average price of $4.82/MMBtu(1)

- **Natural gas (WAHA – Basis Differential)**
  - 2011 Basis swaps contracted for 300,000 MMBtu/month at $(0.53)/MMBtu

- **Oil (NYMEX – West Texas Intermediate)**
  - May 2011 – December 2011 Collars contracted for 1,000 Bbls/d
  - Floor $100.00 – Ceiling $127.00

(1) Based on midpoint of 2011 production guidance.

Appendix

NON-GAAP RECONCILIATIONS

Adjusted Net Income Reconciliation (Unaudited)

The amounts included in the calculation of adjusted net income and adjusted net income per diluted share below were computed in accordance with GAAP. We believe adjusted net income and adjusted net income per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

(in thousands, except per-share amounts)	Three Months Ended June 30,	
	2011	2010
Net income	$ 7,990	$ 1,551
Adjustments for certain items:		
Unrealized (gain) loss on commodity derivatives	(2,231)	1,901
Gain on sale of oil and gas properties	(3)	—
Related income tax effect	760	(646)
Adjusted net income	$ 6,516	$ 2,806
Adjusted net income per diluted share	$ 0.23	$ 0.13

EBITDAX Reconciliation (Unaudited)

We define EBITDAX as net income, plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized (gain) loss on commodity derivatives, (5) gain on sale of oil and gas properties, (6) interest expense, and (7) income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. EBITDAX is presented herein and reconciled to the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund development and exploration activities. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

(in thousands, except per-share amounts)	Three Months Ended June 30,	
	2011	**2010**
Net income	$ 7,990	$ 1,551
Exploration	280	187
Depletion, depreciation and amortization	7,987	5,010
Share-based compensation	1,713	416
Unrealized (gain) loss on commodity derivatives	(2,231)	1,901
Gain on sale of oil and gas properties	(3)	—
Interest expense, net	863	550
Income tax provision	4,400	730
EBITDAX	$ 20,999	$ 10,345
EBITDAX per diluted share	$ 0.73	$ 0.49

F&D Costs Reconciliation (Unaudited)

We believe that providing measures of finding and development, or F&D, cost is useful to assist an evaluation of how much it costs the Company, on a per Boe basis, to add proved reserves. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and to be included in our Annual Report on Form 10-K and to be filed with the SEC on or before March 15, 2012. Due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods before the periods in which related increases in reserves are recorded and development costs may be recorded in periods after the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases (or decreases) in reserves independent of the related costs of such increases.

As a result of the above factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in our filings with the SEC, we cannot assure you that the Company's future F&D costs will not differ materially from those set forth above. Further, the methods we use to calculate F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D costs may not be comparable to similar measures provided by other companies.

The following tables reflect the reconciliation of our estimated finding and development costs to the information required by paragraphs 11 and 21 of ASC 932-235.

Reserve Summary (MBoe)		
Balance – 12/31/2010		50,715
Extensions & discoveries		8,910
Purchases		10,497
Revisions		(2,196)
Production		(1,077)
Balance – 6/30/2011		66,849

Cost Summary ($M)		
Property acquisition		
Unproved properties	$	15,440
Exploration properties		93
Exploration costs		4,914
Development costs		72,061
Working Interest Acquisition		70,181
Total		162,689

Finding & development costs ($/Boe)		
All-in F&D costs	$	9.45
Drill-bit F&D cost	$	8.64

Reserve replacement ratio (%)	
Net reserve adds (MBoe)	17,211
1H'11 Production (MBoe)	(1,077)
Reserve replacement	1,598%