



April 2012

April Investor Presentation





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 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, including, among others, statements and projections regarding the Company's future financial position, operations, performance, business strategy, capital expenditures, returns, budgets, reserves, levels of production and costs and statements regarding the plans and objectives of the Company's management for future operations, are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "estimate," "potential," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which generally are not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, these statements are based on certain assumptions made by the Company based on management's experience, expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Forward-looking statements are not guarantees of performance. Actual results may differ materially from those implied or expressed by the forward-looking statements. Although the Company believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, 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. These include the factors discussed or referenced in the "Risk Factors" section of the Company's Form 10-K and Form 10-Q's filed with the Securities and Exchange Commission ("SEC") and risks relating to declines in the prices we receive for our oil and natural gas, including natural gas liquids; uncertainties about the estimated quantities of oil and natural gas reserves; the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing; risks related to new federal oversight or regulation of over-the-counter derivatives; risks related to the elimination of certain federal income tax deductions currently available to oil and natural gas exploration activities; drilling and operating risks; the adequacy of our capital resources and liquidity, including access to additional borrowing capacity under our credit facility; difficult and adverse conditions in the domestic and global capital and credit markets; risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas; potential financial losses or earnings reductions from our commodity price risk management program; shortages of oilfield equipment, services and qualified personnel and increased costs for such equipment, services and personnel; risks and liabilities associated with acquired properties or businesses; uncertainties about our ability to successfully execute our business and financial plans and strategies; uncertainties about our ability to replace reserves and economically develop our current reserves; general economic and business conditions, either internationally or domestically or in the jurisdictions in which we operate; competition in the oil and natural gas industry; uncertainty concerning our assumed or possible future results of operations; our substantial existing indebtedness and other important factors that could cause actual results to differ materially from those projected.

Accordingly, you should not place undue reliance on any of the Company's forward-looking statements. All forward-looking statements speak only as of the date on which such statements are 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.

This presentation includes financial measures that are not in accordance with generally accepted accounting principals ("GAAP") including EBITDAX, adjusted net income, and cash margin. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of each to the nearest comparable measure in accordance with GAAP, please see the Appendix.



Cautionary Statement Regarding Oil and Gas Quantities

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using the trailing 12-month average first-day-of-the-month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, we currently do not disclose probable or possible reserves in our SEC filings.

In this presentation, proved reserves attributable to the Company at December 31, 2011 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of \$92.71 per Bbl of oil and \$4.12 per MMBtu of natural gas. The Company's estimate of its total proved reserves at December 31, 2011 is based on reports provided by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers.

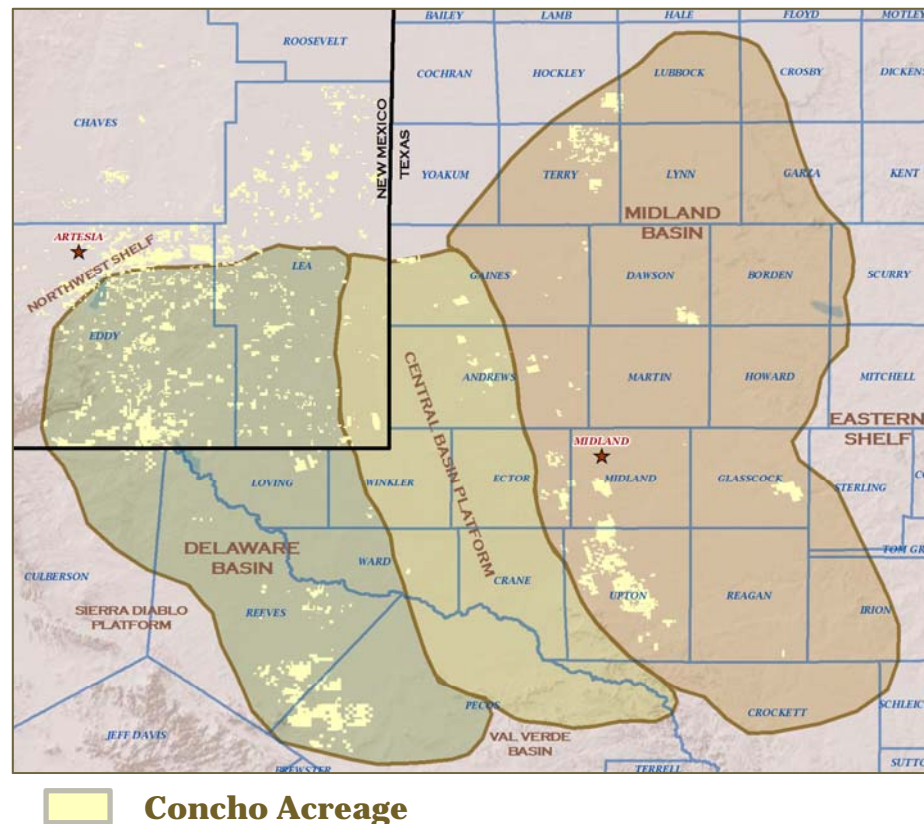
We may use the terms “unproved reserves,” “EUR” per well and “upside potential” to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute “reserves” within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. EUR estimates and drilling locations have not been risked by Company management. Actual locations drilled and quantities that may be ultimately recovered from the Company’s interests could differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed to these quantities. Factors affecting ultimate recovery include the scope of our ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves, per well EUR and upside potential may change significantly as development of the Company’s oil and gas assets provide additional data.

Our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Company Highlights

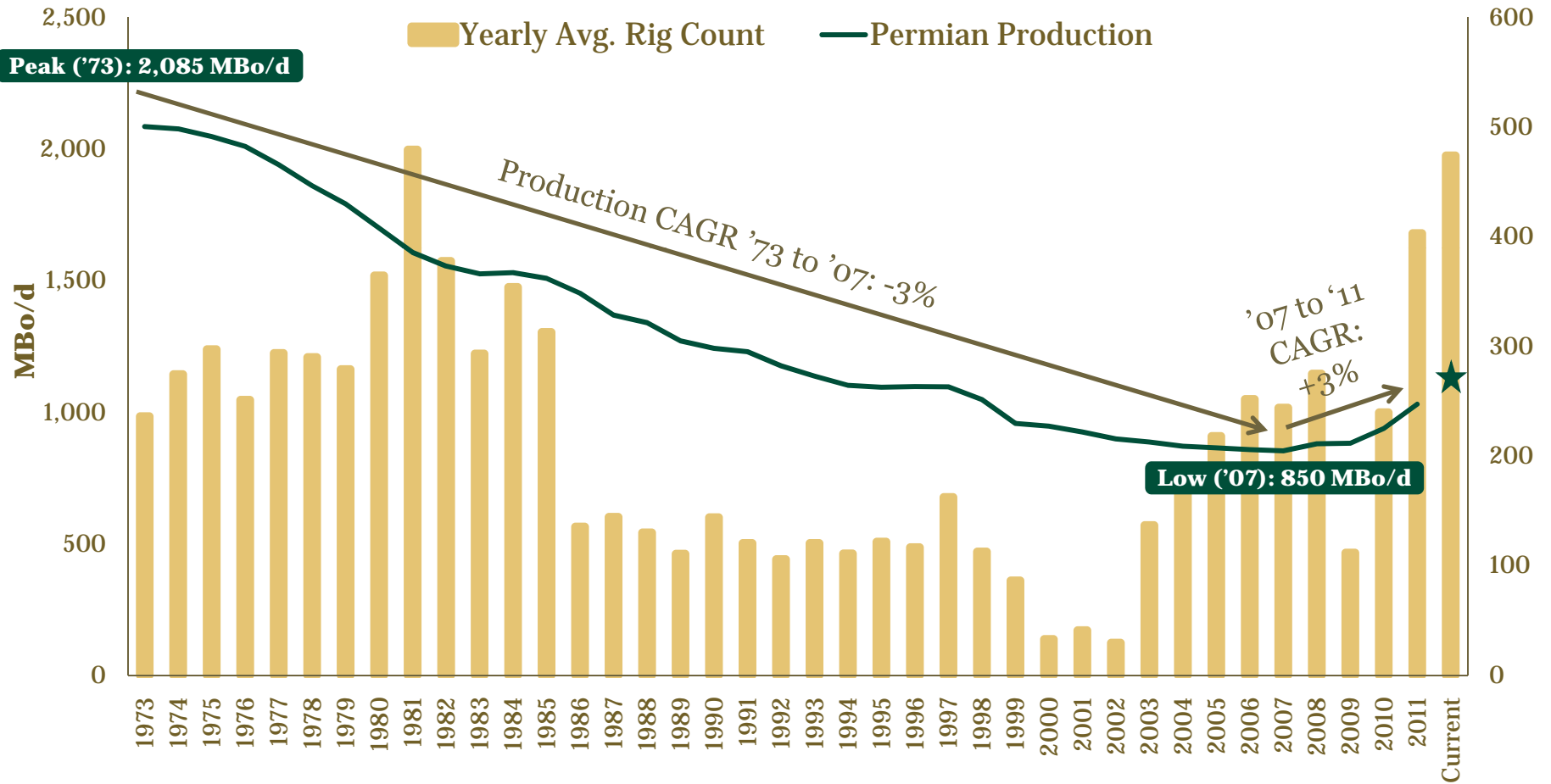
- Leading pure-play Permian Basin operator
- 386.5 MMBoe year-end 2011 proved reserves (+19% over 2010)¹
- Record results in 2011:
 - Drilled 810 gross wells
 - Produced 23.6 MMBoe (+51% over 2010)
 - EBITDAX² of \$1.3 bn (+72% over 2010)
 - Adjusted net income² (non-GAAP) of \$430.1 mm (+69% over 2010)
- 969,026 gross (533,509 net) acres³
- Over 8,900 drilling locations⁴

Permian Basin



1 As of 12/31/11 at SEC pricing. Excludes 13 MMBoe of proved reserves from 1Q 2012 Midland Basin acquisition.
 2 For an explanation of how we calculate and use EBITDAX and adjusted net income and for a reconciliation of net income to EBITDAX and adjusted net income, please see the Appendix.
 3 As of 12/31/11. Excludes acreage from 1Q 2012 Midland Basin acquisition.
 4 As of 12/31/11. Excludes 170 40-acre locations and 200 20-acre locations from 1Q 2012 Midland Basin acquisition.



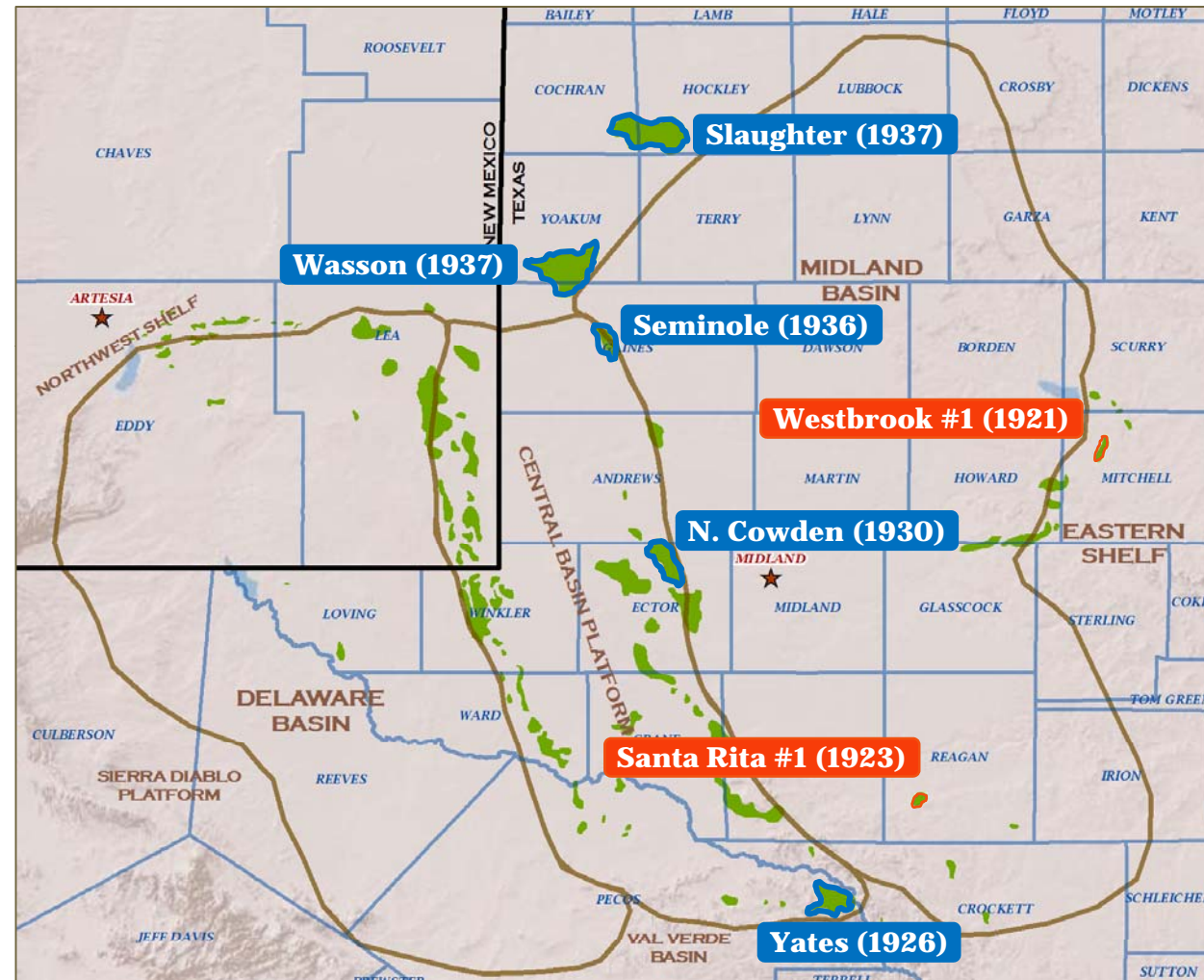


Source: PI/Dwights (IHS), US Energy Information Administration (EIA), and BHI.



Discovery Phase

- Rapid production growth
- Focused on shallow platform targets
- Targeted high permeability carbonate reservoirs in structural traps
- Wells completed without fracturing
- High initial rates (Yates avg. IP: 13 MBo/d)

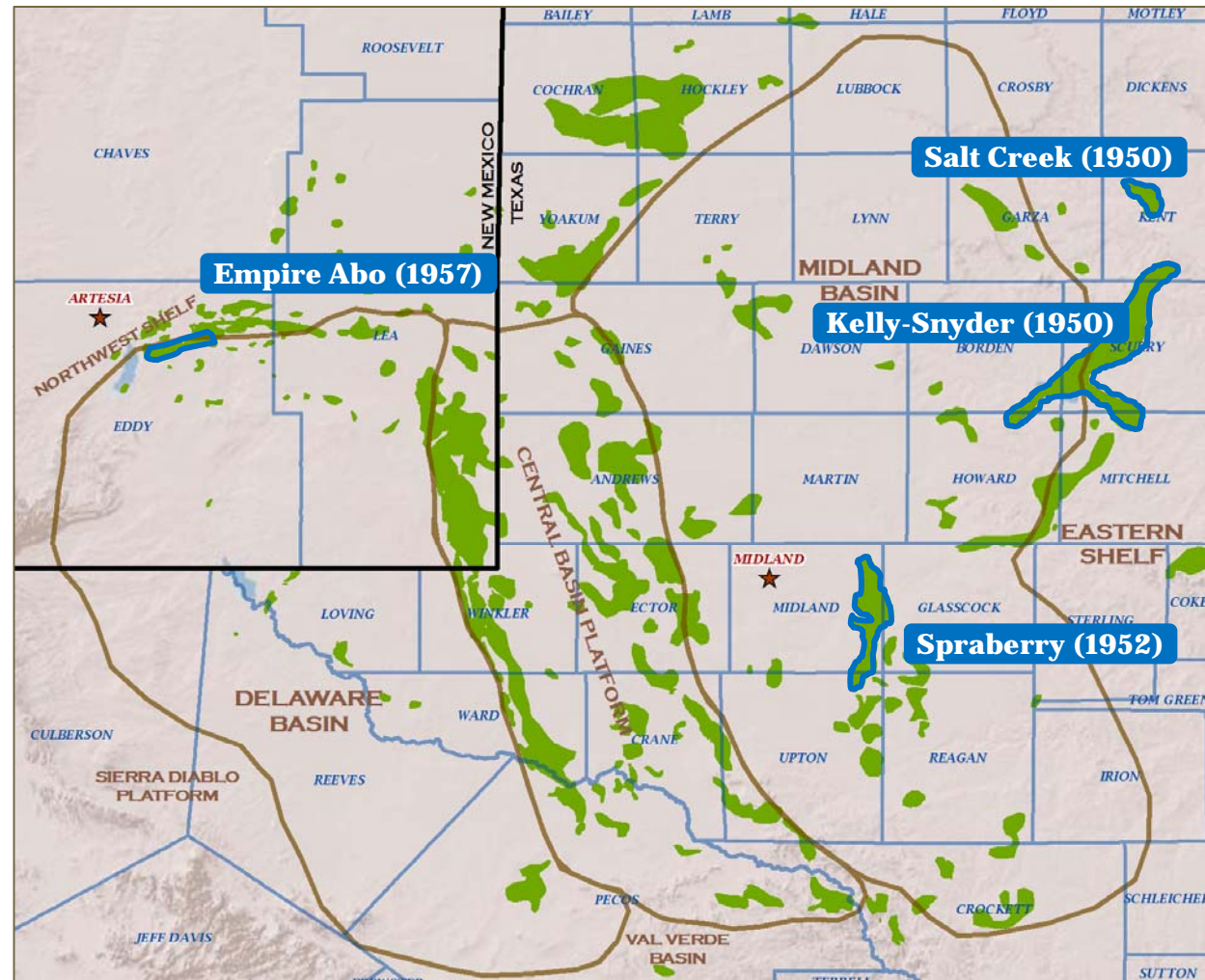


Source: Petroleum Museum, University of Texas Bureau of Economic Geology, DI Desktop.



High Growth Phase

- Stanolind Oil fracs first well in the Hugoton Field (KS) in 1947
- Production increased to 1.2 MMBo/d by end of the '50s
- Continued activity focus on the shelf/platform areas but expanding into the Midland and Delaware basins
- Spraberry discovered in 1952
- Secondary recovery begins

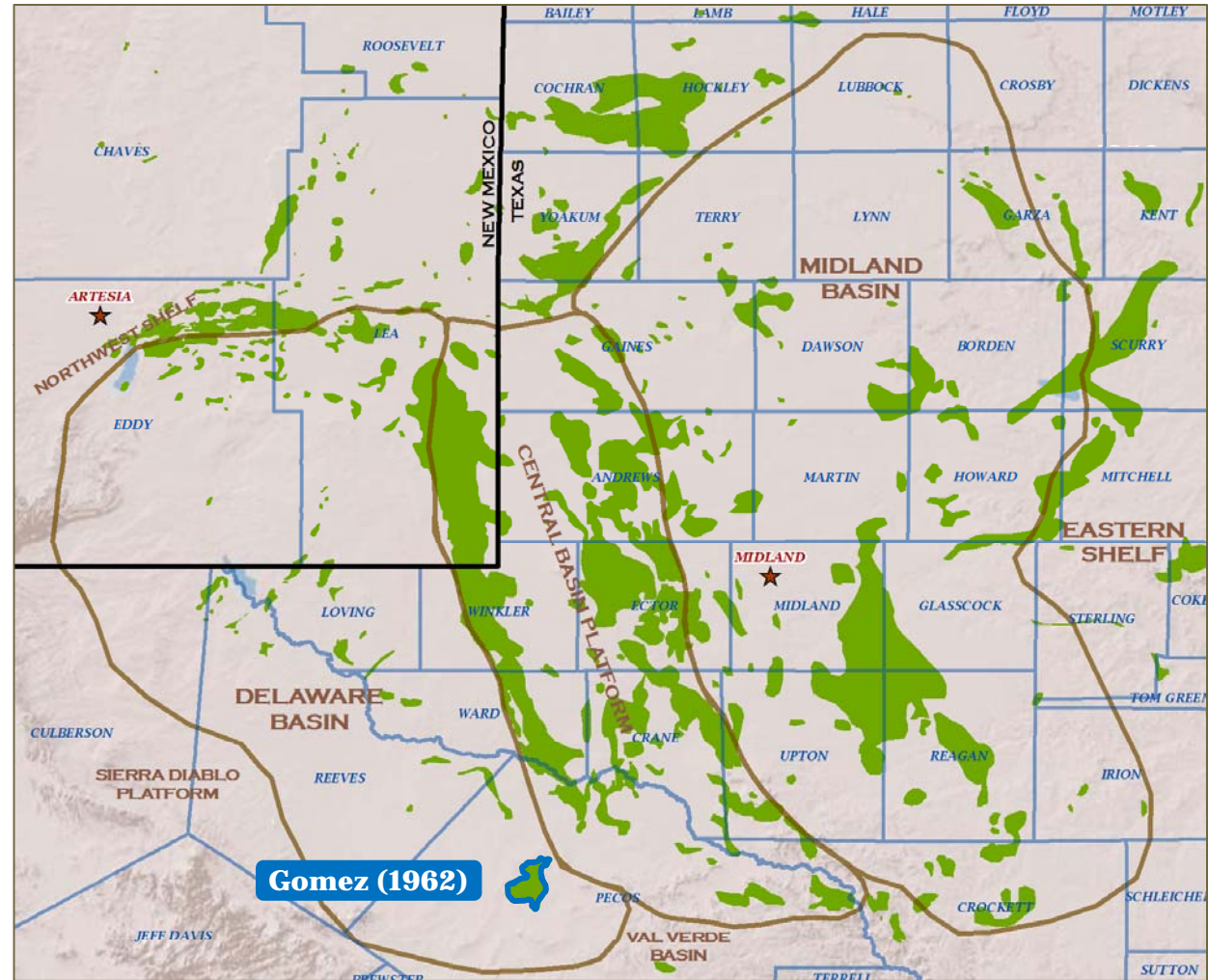


Source: UTPB CEED, Journal of Petroleum Technology, University of Texas Bureau of Economic Geology.



Maturity Phase

- Production increased to 1.5 MMBbl/d as secondary recovery becomes more widespread
- Discovery of new fields diminishes; focused on expanding existing fields
- Central Basin Platform accounts for 61% of new wells in the '60s
- Gas production grows rapidly
 - Gomez Field wells produce in excess of 100 MMcf/d

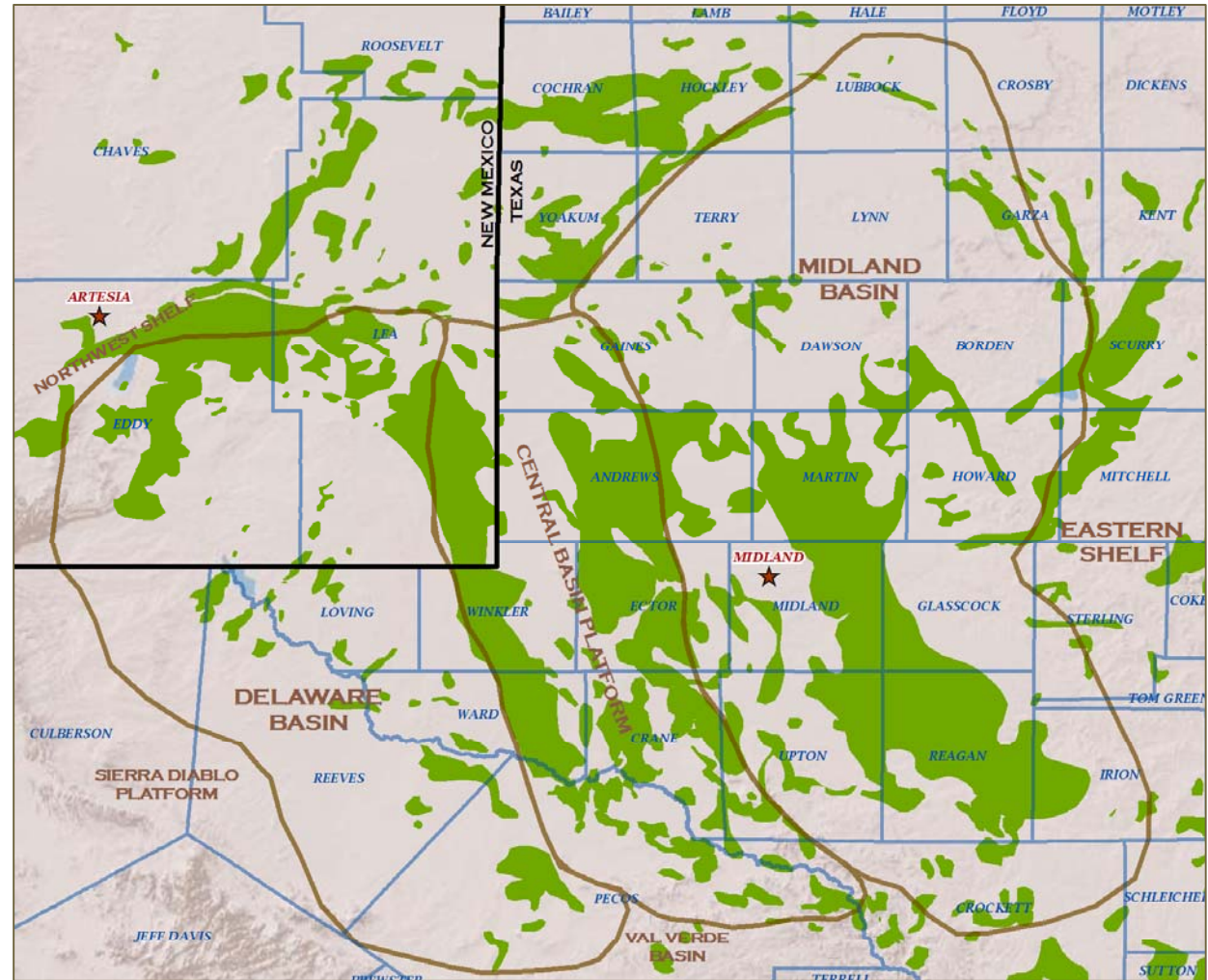


Source: UTPB CEED, University of Texas Bureau of Economic Geology, PI Dwight, DI Desktop.



Decline Phase

- Production peaks at 2 MMB/d in '73
- Operators implement CO₂ floods
- Majors begin to exit
- 28,752 new wells drilled during the '70s (21% are dry holes)

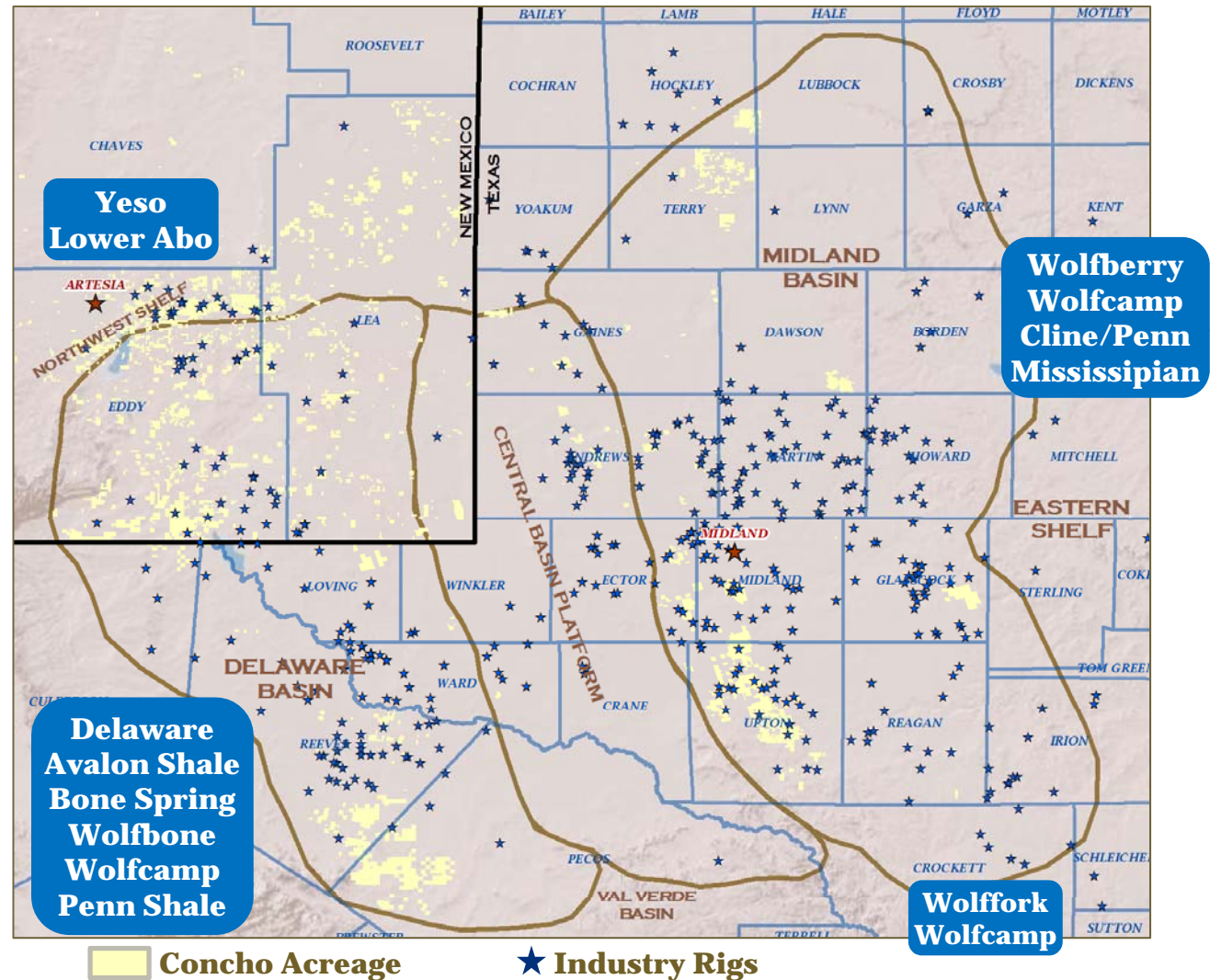


Source: UTPB CEED, University of Texas Bureau of Economic Geology, PI Dwight, DI Desktop.



Renaissance Phase

- Technology expanding resource potential across the Permian Basin
- Activity targeting unconventional reservoirs
- Approximately 475 rigs currently operating
 - >100 horizontal
- Increased activity driven by the emergence of new oil and liquids-rich plays
- Concho is uniquely positioned in the Permian with exposure to some of the most impactful existing and emerging plays



Source: PI Dwrights, BHI.



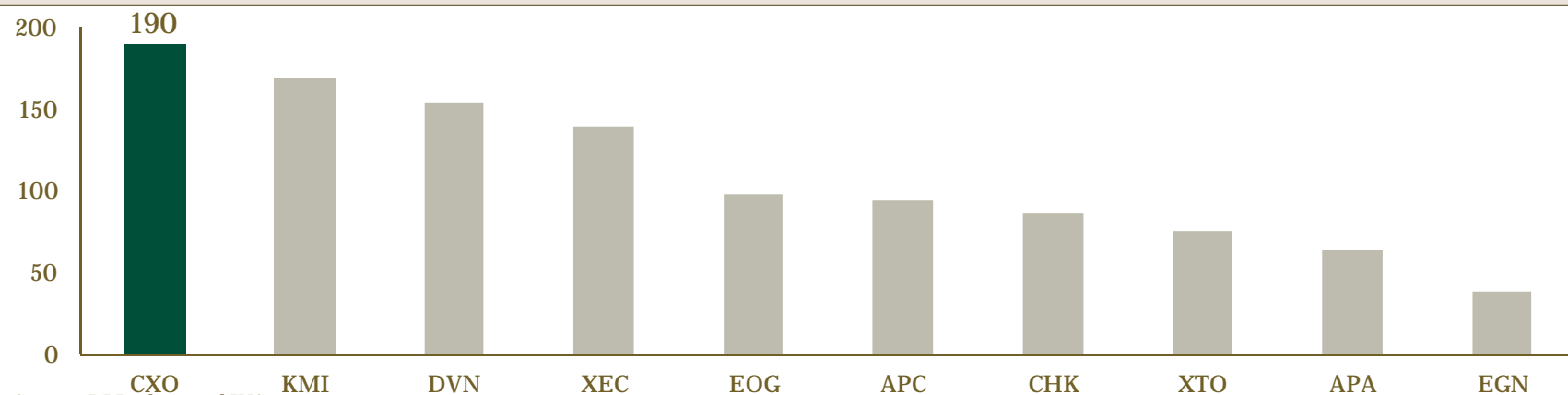


A Leader in the Permian Basin

Permian Gross Operated Production (MBoe/d)¹



Permian Horizontal Wells Drilled by Public Companies (2009 – 2011)



Source: DI Desktop and IHS.

¹ Gross operated production for the month of November 2011.

- Continued focus on the Permian Basin
 - Exposed to some of the most prolific oil plays in the U.S.
 - Capitalize on the strategic benefits of being one of the largest operators in the Permian Basin

- Committed to rate-of-return driven growth
 - Reinvest high-margin cash flows into projects with robust rates of return
 - Achieve superior per share growth rates while staying within cash flow

- Maintain simple, strong financial position
 - Conservative approach to leverage (<2.0x debt / EBITDAX)
 - Ample liquidity of approximately \$1.8bn available under credit facility¹
 - Hedging program to provide predictable cash flows

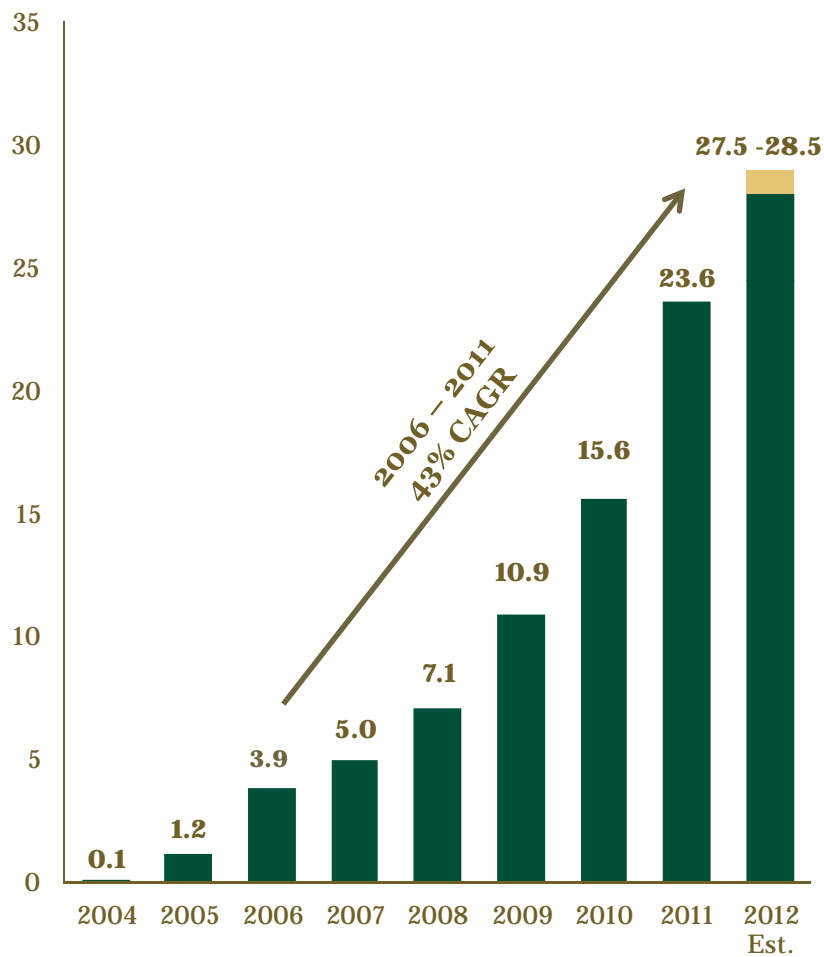
- Pursue acquisitions that enhance existing portfolio
 - Focus on strategic fit and impact to NAV and rate of return

¹ As of 12/31/11, pro forma for 1Q 2012 Midland Basin acquisition and March 2012 bond offering.

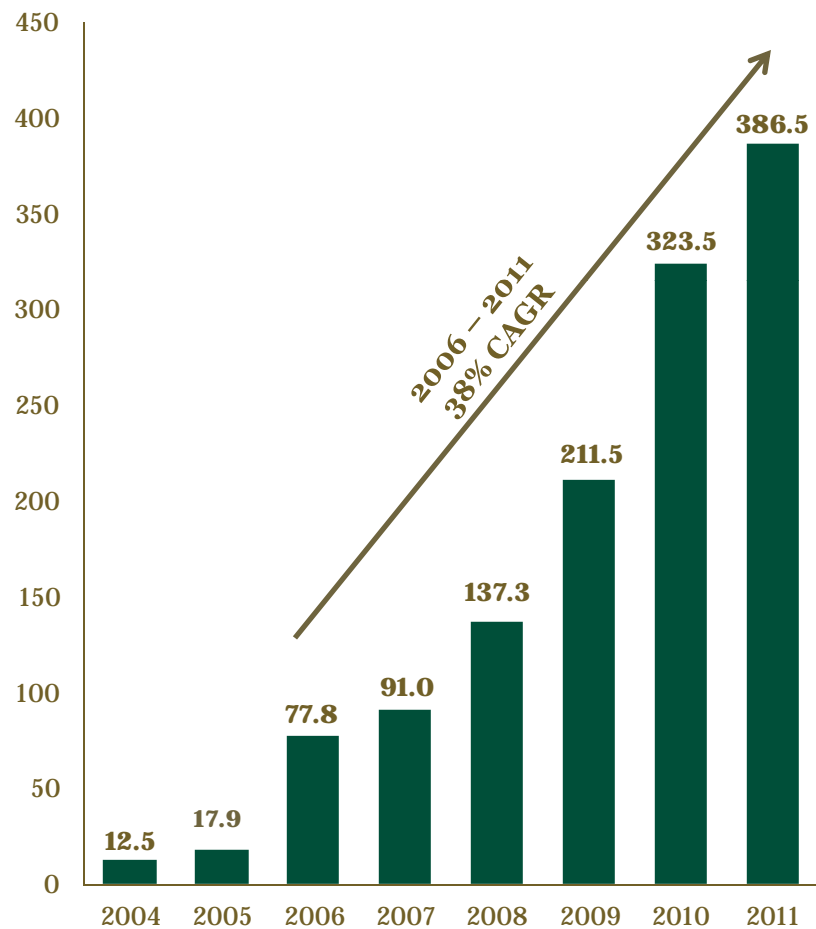


Track Record of Production & Reserve Growth

Annual Production (MMBoe)



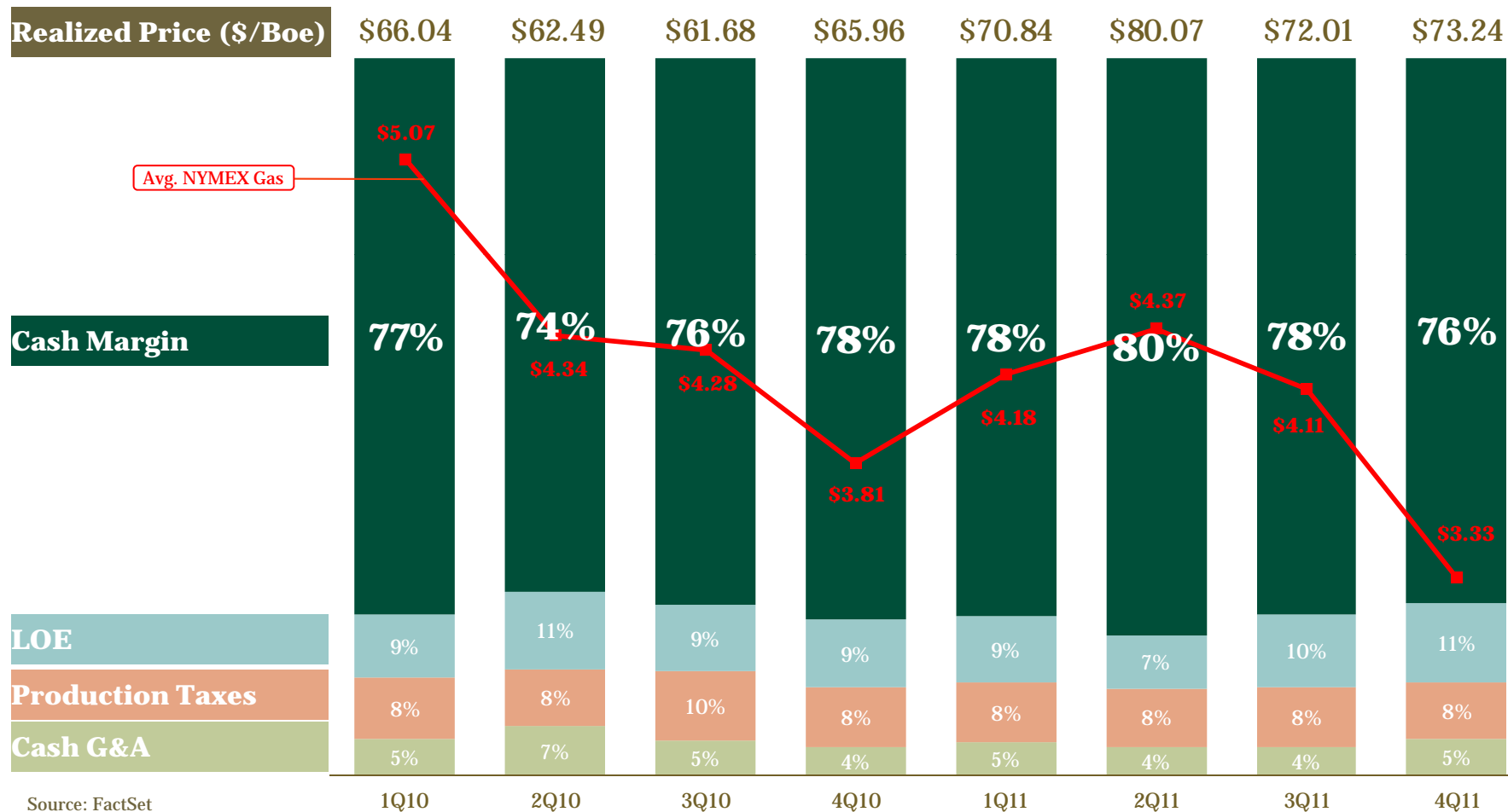
Proved Reserves (MMBoe)





Strong, Liquids-driven Profitability

Unhedged Cash Margin Percentage¹ vs. NYMEX Average Natural Gas Price (\$/MMbtu)



Source: FactSet

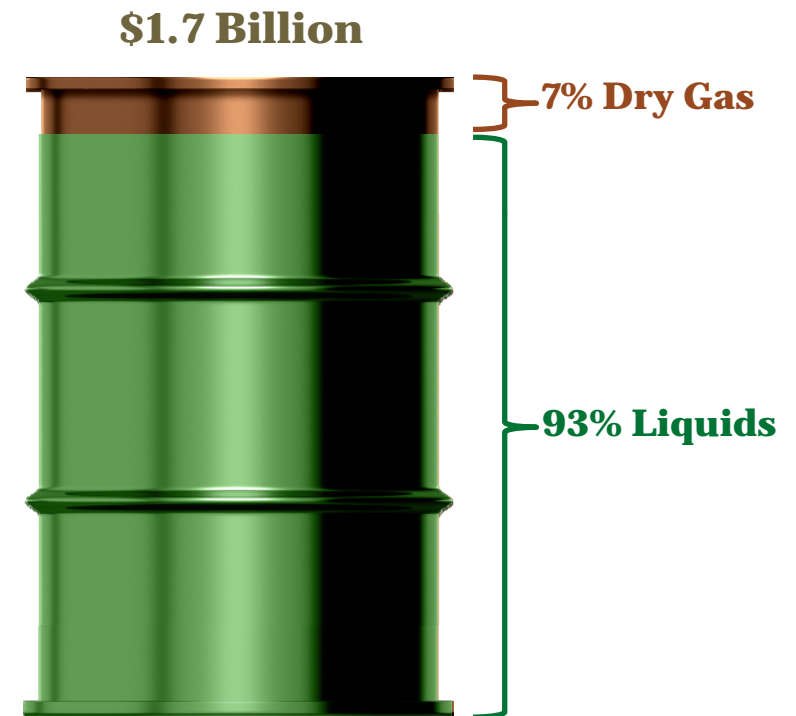
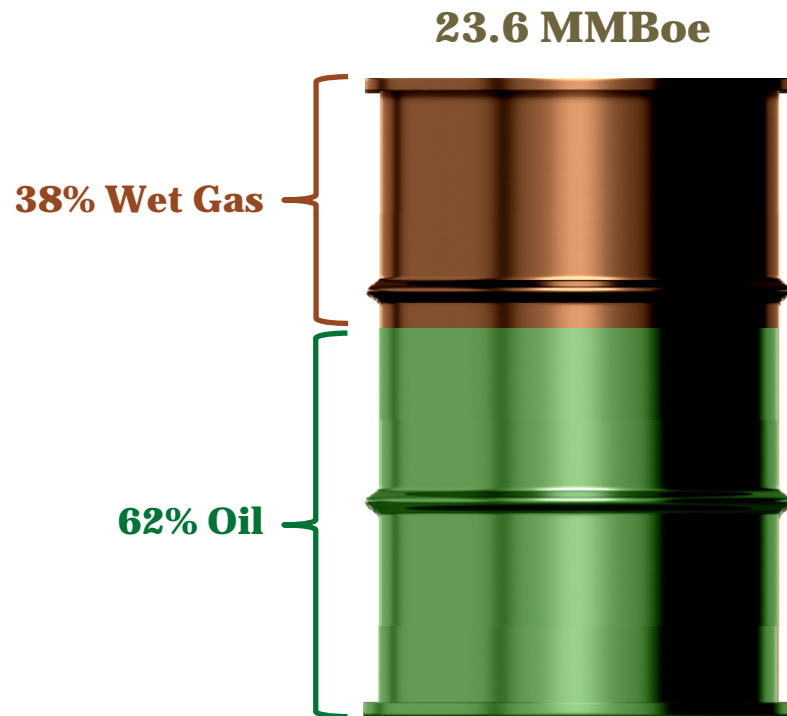
¹ Unhedged Cash Margin represents oil & natural gas revenues, less lease operating expenses, oil and natural gas taxes, cash G&A expense (excludes stock-based compensation), divided by production. See Unhedged Cash Margin Reconciliation in the Appendix for a reconciliation to net income (loss).



Significant Leverage to Oil and Liquids

2011 Production Mix

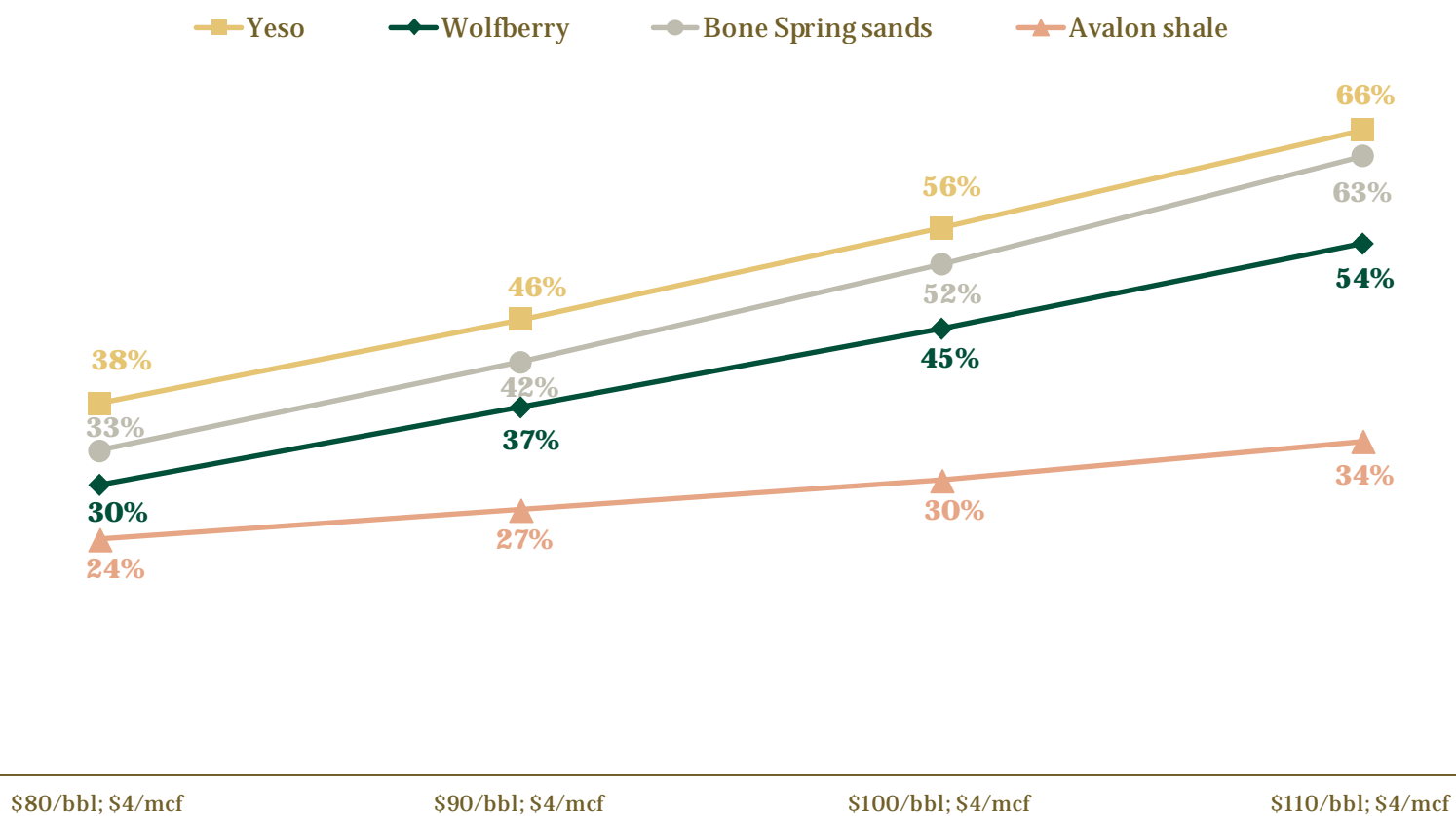
2011 Revenue Contribution





Reinvest High Margin Cash Flow into Robust ROR Projects

Inventory Rates of Return¹

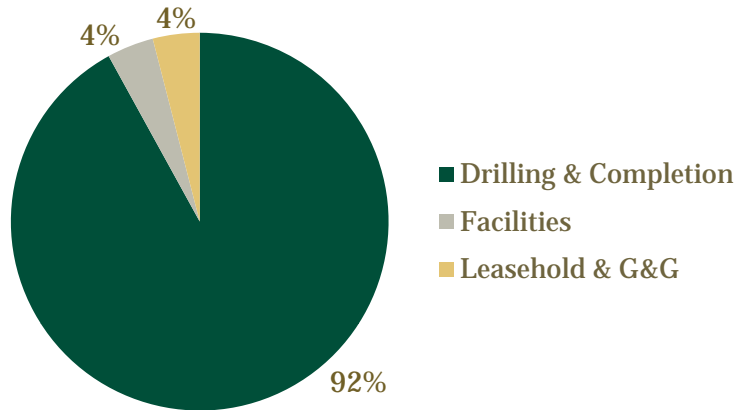


¹ IRRs based on the aggregate economics of the total identified Yeso, Wolfberry, Bone Spring sands and Avalon shale drilling locations at 12/31/2011 and current AFE's. Wolfberry aggregate model excludes 20-acre spaced drilling locations. IRRs exclude interest, federal and state taxes and G&A and do not take into account land cost or hedges.

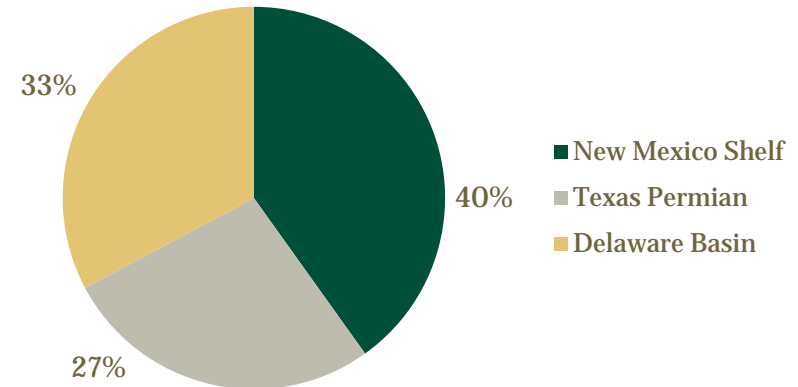


2012 Capital Budget and Activity

2012 Capital Budget: \$1.37bn



2012 Drilling & Completion Budget: \$1.25bn



New Mexico Shelf

- Average 10 rigs drilling in 2012
- Expect to drill ~390 wells in 2012
- 54% of proved reserves¹
- 55% of production in 2011
- 2,715 drilling opportunities²
 - 1,955 Yeso

Delaware Basin

- Average 8 rigs drilling in 2012
- Expect to drill ~140 wells in 2012
- 13% of proved reserves¹
- 20% of production in 2011
- Activity concentrated in the Bone Spring / Avalon Shale
- ~410,000 gross (270,000 net) acres²
- 1,870 drilling opportunities²

Texas Permian

- Average 18 rigs drilling in 2012
- Expect to drill ~350 wells in 2012
- 33% of proved reserves¹
- 25% of production in 2011
- Activity concentrated in Wolfberry play
- 4,320 drilling opportunities³
 - 1,789 40-acre Wolfberry
 - 2,426 20-acre Wolfberry

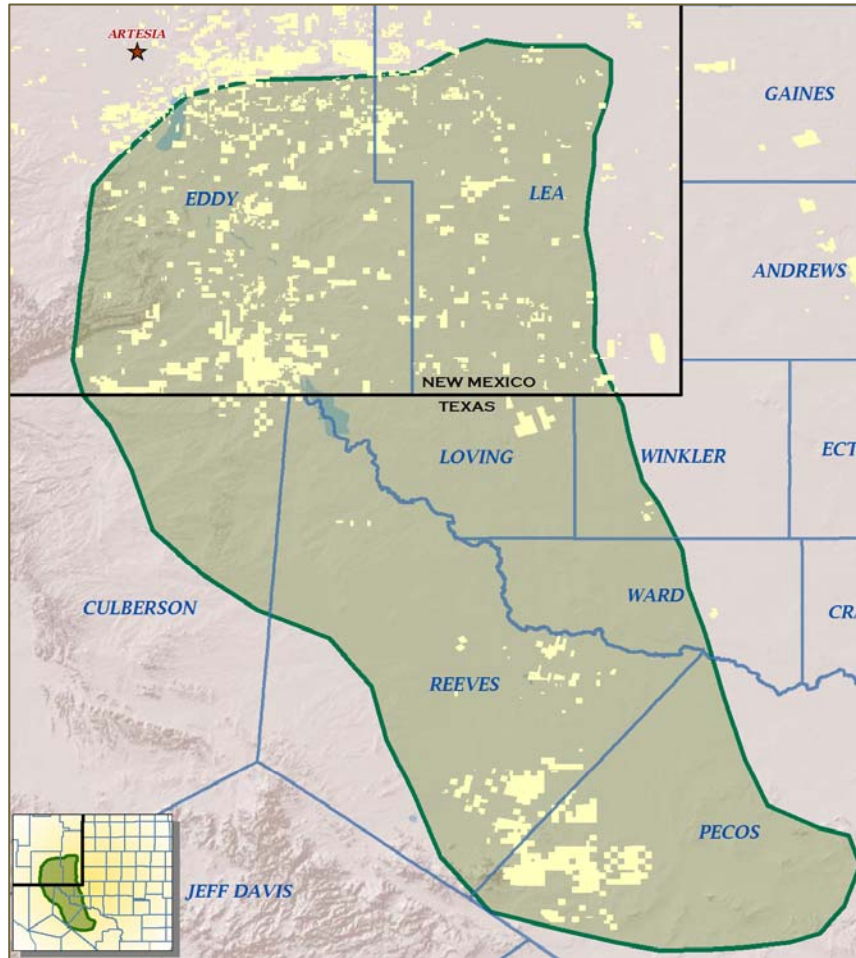
¹ As of 12/31/11 at SEC pricing. Excludes 13 MMBoe of proved reserves from 1Q 2012 Midland Basin acquisition.

² As of 12/31/11.

³ As of 12/31/11. Excludes 170 40-acre locations and 200 20-acre locations from 1Q 2012 Midland Basin acquisition.

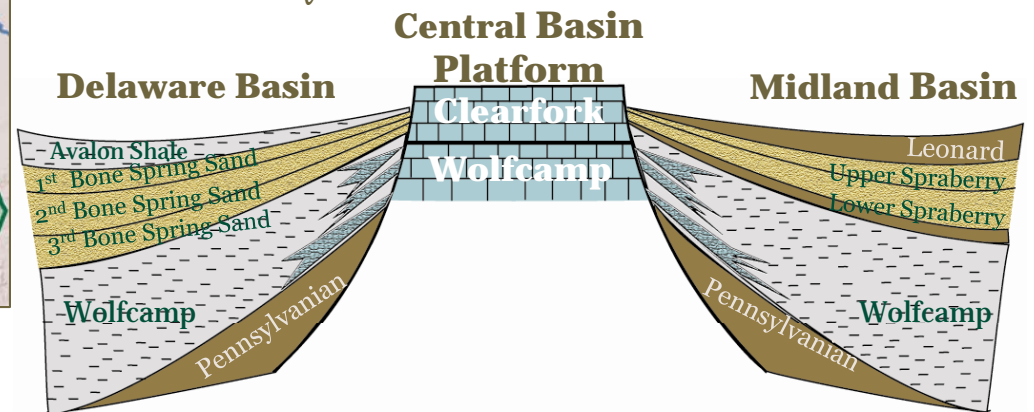


Delaware Basin – Overview



 **Concho Acreage**

- Bone Spring play – targeting Avalon shale, Bone Spring sands and Wolfcamp shale – is one of the most active emerging liquids plays in the U.S.
- Additional targets: Delaware sands, Penn shale
- Significant multi-stacked pay potential
 - Expect to test multi-zone development concepts in 2012
- Approximately 410,000 gross (270,000 net) acres
- Identified 1,870 locations at year-end 2011
- Net Bone Spring play production of 11.4 MBoe/d during 4Q11
 - 28% growth over 3Q11 and 250% growth over 4Q10





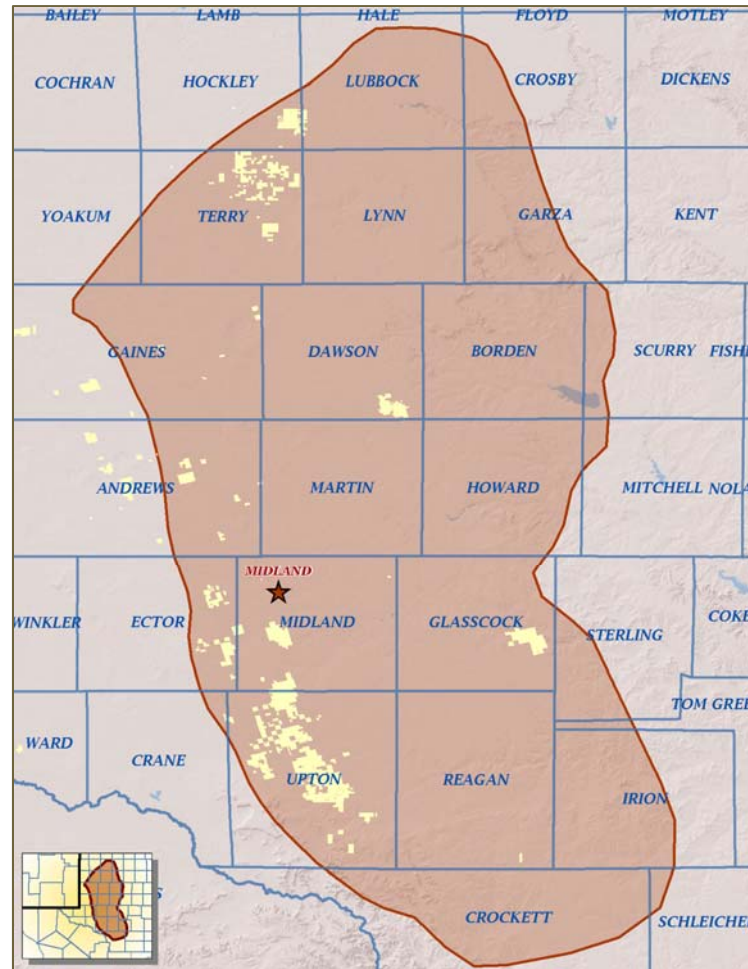
Texas Permian – Midland Basin

North Midland Basin – *New Play*

- Early mover establishing large, contiguous position through greenfield leasing efforts
 - Over 60,000 gross acres with high WI and actively leasing
- Multi-stacked pay potential primarily targeting Wolfcamp/Cline shale
- Currently drilling first well in Terry County
- Expected production mix similar to Wolfberry

Wolfberry

- Technical team has drilled 1,000 wells
- Wolfberry well characteristics (40-acres):
 - Drill and complete: \$1.6 - \$1.8mm
 - EUR: 140 MBoe
 - 30-day IP: 95 - 125 Boepd
 - TVD: 7,500' - 11,000'
 - 8 - 10 frac stages
- Plan to drill two horizontal Wolfcamp shale wells in 2012; continue to test opportunities in eastern Midland Basin

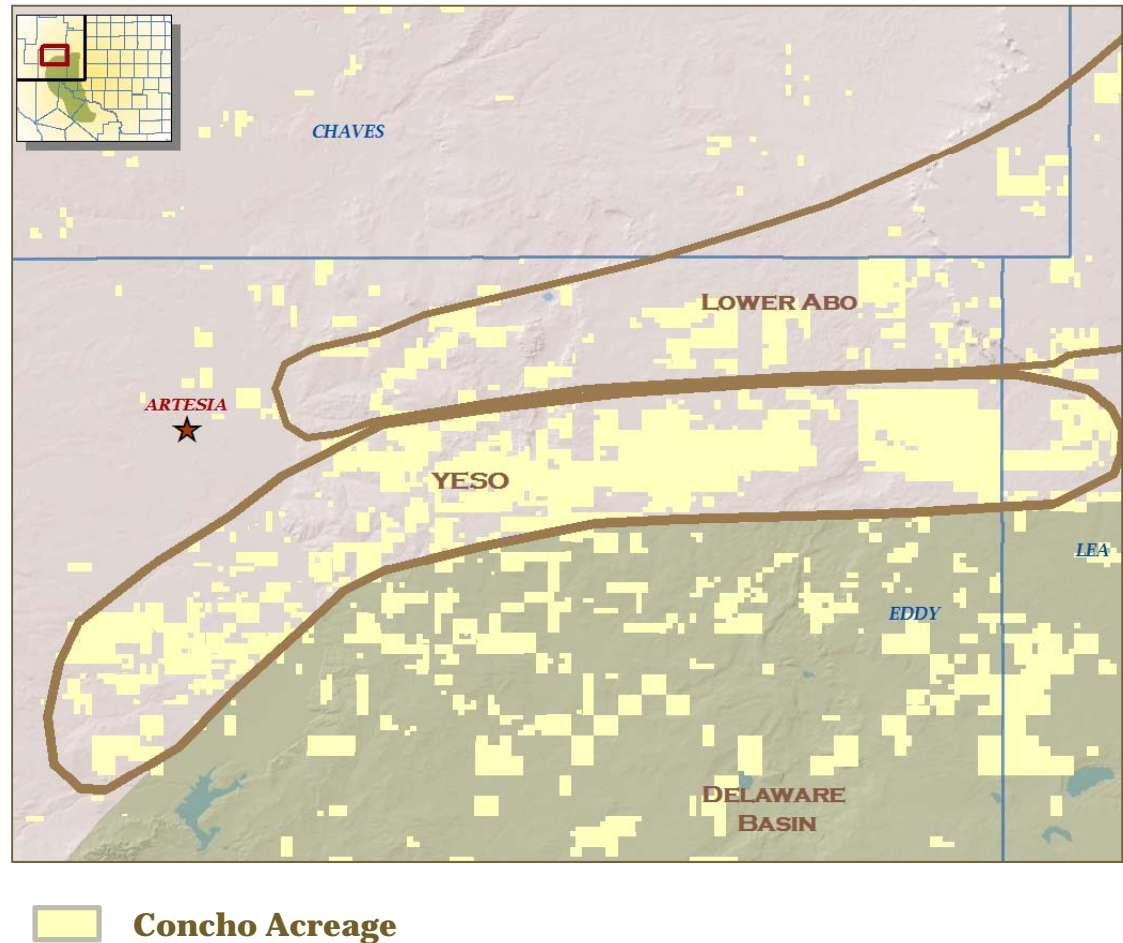


 **Concho Acreage**

SYSTEM	SERIES EPOCH	MIDLAND BASIN	
Permian	Guadalupe	Tansill	
		Yates	
		7 Rivers	
		Queen	
		Grayburg	
	Leonard	San Andres	
		San Angelo	
		Upper Leonard	
		Upper Spraberry	
		Lower Spraberry	
Pennsylvanian	Wolfcamp	Wolfcamp	
		Cisco	
		Canyon	
		Strawn	
		Bend	
	Mississippian	U. Mississippian Lm	U. Mississippian Lm
			L. Mississippian Lm
			Kinderhook
			Woodford
			Devonian
Silurian	U. Niagaran	Upper Silurian	
		Fuselman	
		Sylvan Sh	
		Montoya	
		Bromide	
	Ordovician	Simpson	Tulip Creek
			McKee
			McLish
			Waddell
			Oil Creek
Cambrian	Upper	Joins	
		Ellenburger	
		Wilberne	
		Hickory	
		Precambrian	

Shelf Overview

- Currently operating 9 Yeso rigs, 1 Lower Abo rig
- Concho has drilled over 1,000 wells in the Yeso
- Vertical Yeso well characteristics:
 - Drill and complete costs: \$1.6mm
 - EUR: 145 MBoe
 - 30-day IP rate: 110 - 140 Boepd
 - TVD: 5,000' - 7,000'
 - 7 - 10 days to drill
- Expanding the play boundary through horizontal development
- Actively increasing acreage position





Why Invest in Concho?

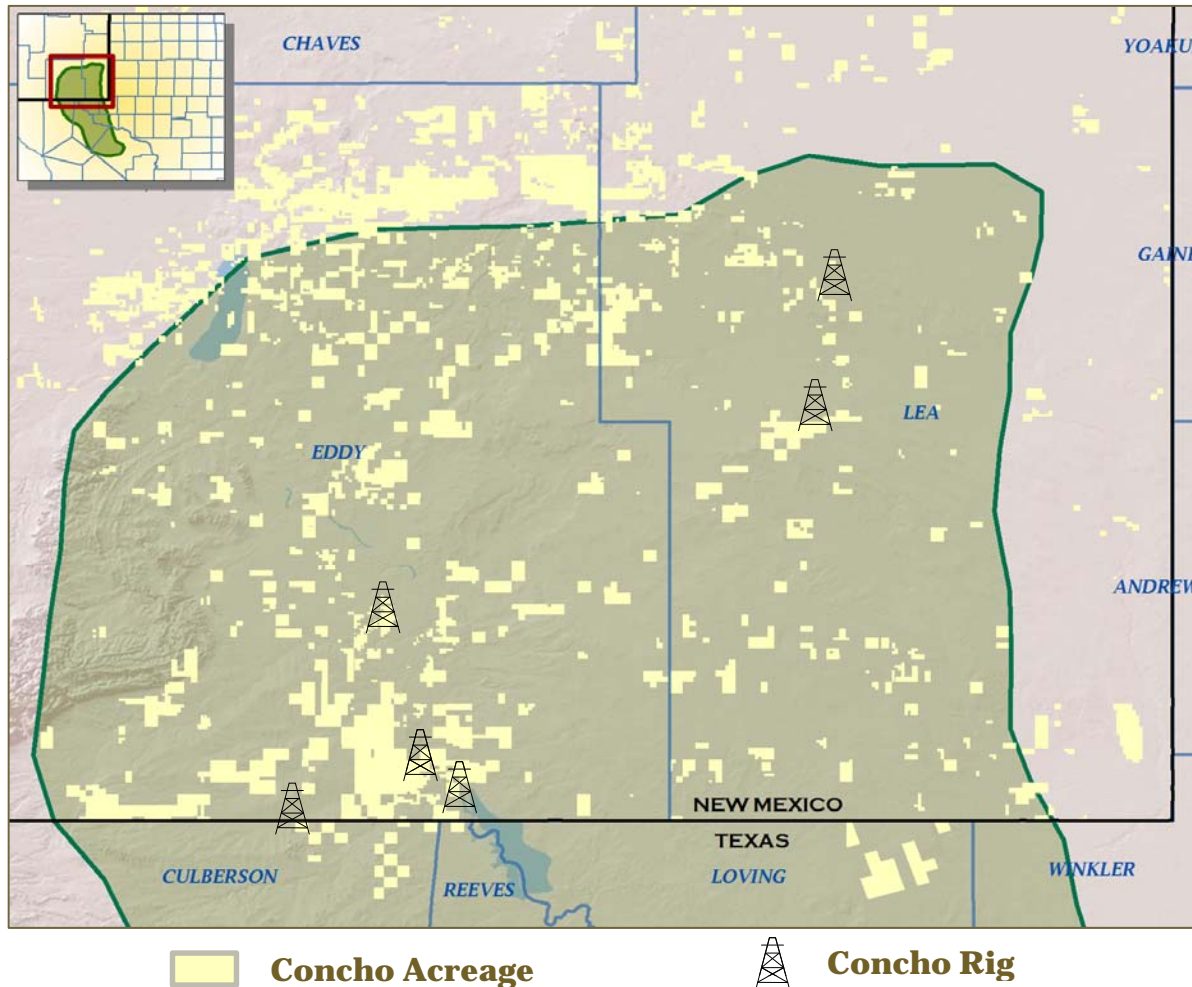
- Leading Permian producer with focused operations in three core plays – Yeso, Delaware Basin and Wolfberry
- Large, predominately oil and liquids-rich resource base
- Significant potential for reserve and production growth from over 8,900 drilling locations¹
- Compelling margins due to strong price realizations and low cost structure
- Balance sheet and liquidity positioned for future growth; history of capital discipline
- Proven management team with demonstrated track record of operational excellence, capital discipline and acquisition expertise

¹ As of 12/31/11. Excludes 170 40-acre locations and 200 20-acre locations from 1Q 2012 Midland Basin acquisition.



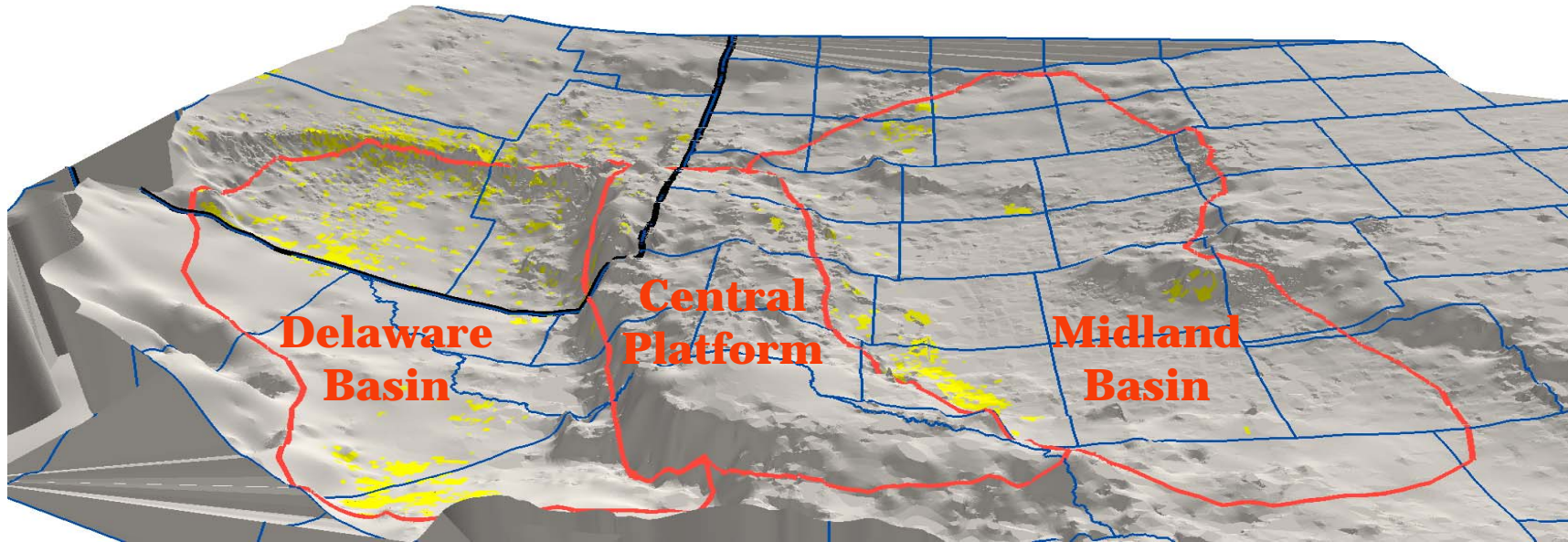


Northern Delaware Basin



- 1,417 locations¹ targeting:
 - Avalon shale
 - Bone Spring sands
 - Wolfcamp shale
- Additional targets:
 - Delaware sands
 - Penn shale
- Drill and complete: \$5 - \$9mm
- EURs: 400 - 700 MBoe
- 30-day IP: 300 - 1,300 Boepd
- TVD: 8,500' - 9,500'
- Lateral length: 4,000' - 4,500'
- 8 - 13 frac stages

¹ As of 12/31/11.



PERIOD	SERIES	DELAWARE BASIN		PERIOD	SERIES	CENTRAL PLATFORM		PERIOD	SERIES	MIDLAND BASIN	
		FORMATION				FORMATION				FORMATION	
GUADALAUPE	DELAWARE GROUP	LAMAR BELL CANYON		GUADALAUPE	WHITE-HORSE	TANSILL		GUADALAUPE	WHITE-HORSE	TANSILL	
		CHERRY CANYON				YATES				YATES	
		BRUSHY CANYON				7 RIVERS				7 RIVERS	
LEONARD		UPPER AVALON SHALE		LEONARD	WARD	QUEEN		LEONARD	WARD	QUEEN	
		LOWER AVALON SHALE				GRAYBURG				GRAYBURG	
		1ST BONE SPRING				SAN ANDRES				SAN ANDRES	
		2ND BONE SPRING				GLORIETA				GLORIETA	
		3RD BONE SPRING				PADDOCK				PADDOCK	
WOLFCAMP		WOLFCAMP		WOLFCAMP	YESO	BLINEBRY		LEONARD	CLEAR FORK	UPPER LEONARD	
		PENNSYLVANIAN				TUBB				UPPER SPRABERRY	
PENN		WOLFCAMP		PENN		DRINKARD		WOLFCAMP		LOWER SPRABERRY	
		PENNSYLVANIAN				ABO				DEAN	
PENN		WOLFCAMP		PENN		HUECO BURSUM		WOLFCAMP		WOLFCAMP	
		PENNSYLVANIAN				PENNSYLVANIAN				PENNSYLVANIAN	



EBITDAX Reconciliation

(in thousands)	Years Ended December 31,	
	2011	2010
Net income	\$ 548,137	\$ 204,370
Exploration and abandonments	11,779	10,324
Depreciation, depletion and amortization	428,377	241,642
Accretion of discount on asset retirement obligations	2,965	1,482
Impairments of long-lived assets	439	11,614
Non-cash stock-based compensation	19,271	12,931
Bad debt expense	-	870
Unrealized (gain) loss on derivatives not designated as hedges	(61,504)	73,501
Loss on sale of assets, net	1,139	58
Interest expense	118,360	60,087
Income tax expense on continuing operations	285,848	115,278
Discontinued operations	(79,652)	10,837
EBITDAX	<u>\$ 1,275,159</u>	<u>\$ 742,994</u>

We define EBITDAX as net income, plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense (7) unrealized (gain) loss on derivatives not designated as hedges, (8) loss on sale of assets, net (9) interest expense, (10) federal and state income taxes on continuing operations and (11) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income or cash flow as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable assets, none of which are components of EBITDAX. EBITDAX as used by us may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis.



Adjusted Net Income Reconciliation

The following provides information that the Company believes may be useful to investors who follow the practice of some industry analysts who adjust company earnings and cash flows from operating activities to match realizations to production settlement months and make other adjustments to exclude certain non-cash items.

The following table provides a reconciliation of net income (GAAP) to adjusted net income (non-GAAP).

(in thousands, except per share amounts)	Years Ended December 31,	
	2011	2010
Net income - as reported	\$ 548,137	\$204,370
Adjustments for certain non-cash items:		
Unrealized mark-to-market (gain) loss on commodity and interest rate derivatives	(61,504)	73,501
Impairments of long-lived assets	439	11,614
Leasehold abandonments	5,735	7,575
Discontinued operations:		
Impairments of long-lived assets	-	3,567
Gain on sale of assets	(135,943)	(29,112)
Tax impact ^(a)	73,258	(25,649)
Change in state statutory effective income tax rate	-	8,278
Adjusted net income	<u>\$ 430,122</u>	<u>\$ 254,144</u>
Adjusted basic earnings per share:		
Adjusted net income per share	\$ 4.19	\$ 2.75
Weighted average shares used in adjusted basic earnings per share	102,581	92,542
Adjusted diluted earnings per share:		
Adjusted net income per share	\$ 4.15	\$ 2.71
Weighted average shares used in adjusted diluted earnings per share	103,653	93,837

(a) The tax impact is computed utilizing the Company's statutory effective federal and state income tax rates excluding the effects of permanent rate differences. The income tax rates were 38.3% and 38.2% for the years ended December 31, 2011 and 2010, respectively.



Unhedged Cash Margin Reconciliation

(\$ in thousands, except per unit data)	1Q 2010	2Q 2010	3Q 2010	4Q 2010	1Q 2011	2Q 2011	3Q 2011	4Q 2011	Years Ended December 31,	
									2011	2010
Net income (loss)	\$ 67,540	\$ 124,171	\$ 20,775	\$ (8,116)	\$ 42,575	\$ 232,182	\$ 356,205	\$ (82,825)	\$ 548,137	\$ 204,370
Exploration and abandonments	1,109	922	3,617	4,676	726	400	3,498	7,155	11,779	10,324
Depreciation, depletion and amortization	50,159	49,611	57,624	84,248	90,288	98,881	115,730	123,478	428,377	241,642
Accretion of discount on asset retirement obligations	341	316	349	476	704	715	751	795	2,965	1,482
Impairments of long-lived assets	256	3,489	1,922	5,947	-	76	-	363	439	11,614
Non-cash stock-based compensation	2,831	2,871	3,152	4,077	4,468	4,725	4,673	5,405	19,271	12,931
(Gain) loss on derivatives not designated as hedges	(15,573)	(112,763)	66,107	149,554	233,142	(144,882)	(385,222)	320,312	23,350	87,325
Interest expense	11,065	11,192	12,036	25,794	29,660	21,660	32,881	34,159	118,360	60,087
Other (income) expense, net	73	304	3,521	6,415	352	1,735	2,503	(616)	3,974	10,313
Income tax expense (benefit)	38,763	72,220	7,392	(3,097)	(30,469)	143,270	221,199	(48,152)	285,848	115,278
Discontinued operations (a)	7,470	8,229	7,030	(11,927)	(83,306)	-	-	3,654	(79,652)	10,802
Unhedged Cash Margin	\$ 164,034	\$ 160,562	\$ 183,525	\$ 258,047	\$ 288,140	\$ 358,762	\$ 352,218	\$ 363,728	\$ 1,362,848	\$ 766,168
Production	3,210 MBoe	3,452 MBoe	3,899 MBoe	5,002 MBoe	5,228 MBoe	5,573 MBoe	6,311 MBoe	6,532 MBoe	23,644 MBoe	15,564 MBoe
Unhedged Cash Margin (\$/Boe)	\$ 51.10	\$ 46.51	\$ 47.07	\$ 51.59	\$ 55.11	\$ 64.38	\$ 55.81	\$ 55.68	\$ 57.64	\$ 49.23
Average price without derivatives (\$/Boe)	\$ 66.04	\$ 62.49	\$ 61.68	\$ 65.96	\$ 70.84	\$ 80.07	\$ 72.01	\$ 73.24	\$ 73.98	\$ 64.54
Unhedged Cash Margin (%)	77%	74%	76%	78%	78%	80%	78%	76%	78%	76%

Unhedged cash margin per BOE (as defined above) is presented herein, and reconciled to the generally accepted accounting principle ("GAAP") measure of net income (loss). Management believes this presentation may be helpful to investors as it represents the cash generated by our oil and natural gas assets that is available for reinvestment. Concho management uses this information to analyze operating trends for comparative purposes within the industry. This measure is not intended to replace GAAP statistics but rather to provide additional information that may be helpful in evaluating trends and performance.

(a) Includes similar items as listed above, including the (gain) loss on sale of assets, net that are presented in discontinued operations.



Hedges as of April 2, 2012

	2012				Total	2013	2014	2015	2016
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter					
Oil Swaps:									
Volume (Bbl)	3,662,500	3,539,500	3,193,500	2,941,500	13,337,000	10,055,000	2,707,000	692,000	81,000
NYMEX price (Bbl) (a)	\$ 94.30	\$ 94.27	\$ 95.16	\$ 95.07	\$ 94.67	\$ 95.12	\$ 89.99	\$ 85.24	\$ 89.65
Natural Gas Swaps:									
Volume (MMBtu)	75,000	75,000	75,000	75,000	300,000	-	-	-	-
NYMEX price (MMBtu) (b)	\$ 6.54	\$ 6.54	\$ 6.54	\$ 6.54	\$ 6.54	-	-	-	-

(a) The index prices for the oil contracts are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas contracts are based on the NYMEX-Henry Hub last trading day of the month futures price.



Production:	
Oil equivalent (MMBoe)	27.5 - 28.5
% Oil	60% - 63%
Price differentials to NYMEX:	
(excluding the effects of hedging)	
Oil (Bbl)	93% - 95%
Natural gas (Mcf)	140% - 160%
Operating costs and expenses:	
Lease operating expense:	
Direct lease operating expense (\$/Boe)	\$6.80 - \$7.20
Oil & natural gas taxes (% of oil and natural gas revenue)	8.25%
G&A expense:	
Cash G&A expense (\$/Boe)	\$3.25 - \$3.50
Non-cash stock based compensation (\$/Boe)	\$0.80 - \$0.90
DD&A expense (\$/Boe)	\$18.00 - \$20.00
Exploration, abandonments and G&G (\$/Boe)	\$0.50 - \$1.50
Cash interest rates:	
\$300 million senior notes due 2017	8.625%
\$600 million senior notes due 2021	7.000%
\$600 million senior notes due 2022	6.500%
\$600 million senior notes due 2022	5.500%
Remainder of debt	LIBOR + (150 - 250 bps)
Income taxes:	38%
Percent deferred of total taxes	80% - 90%
Capital expenditures (\$ in billions)	\$1.37