November 2012

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 timing and estimated proceeds of the closing of our non-core asset sale and 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.

Proved reserves estimated for the 1Q12 Midland Basin acquisition at November 1, 2011 are internal estimates based on a price of $85.00 per Bbl of oil and $4.00 per MMBtu of natural gas held flat over the life of the reserves, and are not determined in accordance with SEC rules. Accordingly, proved reserves actually booked for the PDC acquisition in the Company's SEC filings may be lower than the internal estimates included in this presentation.

Proved reserves estimated for the Three Rivers acquisition at April 1, 2012 are internal estimates based on a price of $98.20 per Bbl of oil and $4.24 per MMBtu of natural gas held flat over the life of the reserves, and are not determined in accordance with SEC rules. Accordingly, proved reserves actually booked for the Three Rivers acquisition in the Company's SEC filings may be lower than the internal estimates included in this presentation.

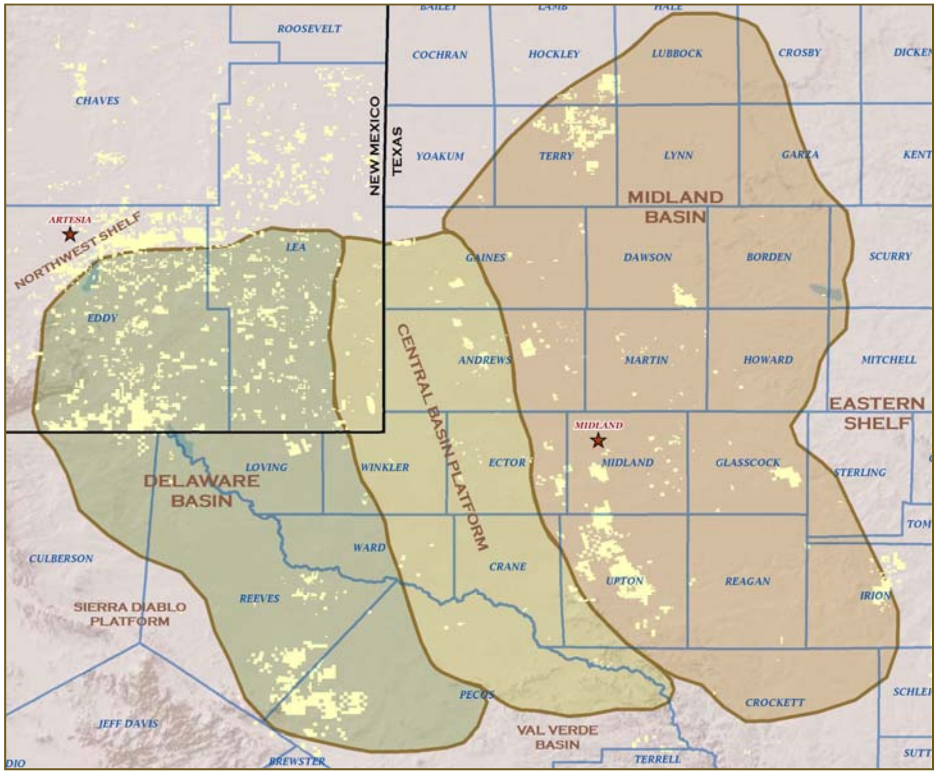
We may use the terms "unproved reserves," "EUR" per well and "upside potential" to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are the Company's internal estimates of hydrocarbon quantities that may be potentially 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
- 458 MMBoe year-end 2011 estimated proved reserves[1]
- Results in 3Q 2012:
  - Drilled 213 gross wells
  - Produced 7.8 MMBoe
  - EBITDAX[2] of $387.2mm
  - Adjusted net income[2] (non-GAAP) of $99.8mm
- Approximately 1.3mm gross (750,000 net) acres[3]
- Over 10,600 drilling locations[3]
- Recently announced sale of non-core assets for $520mm

Permian Basin



Concho Acreage

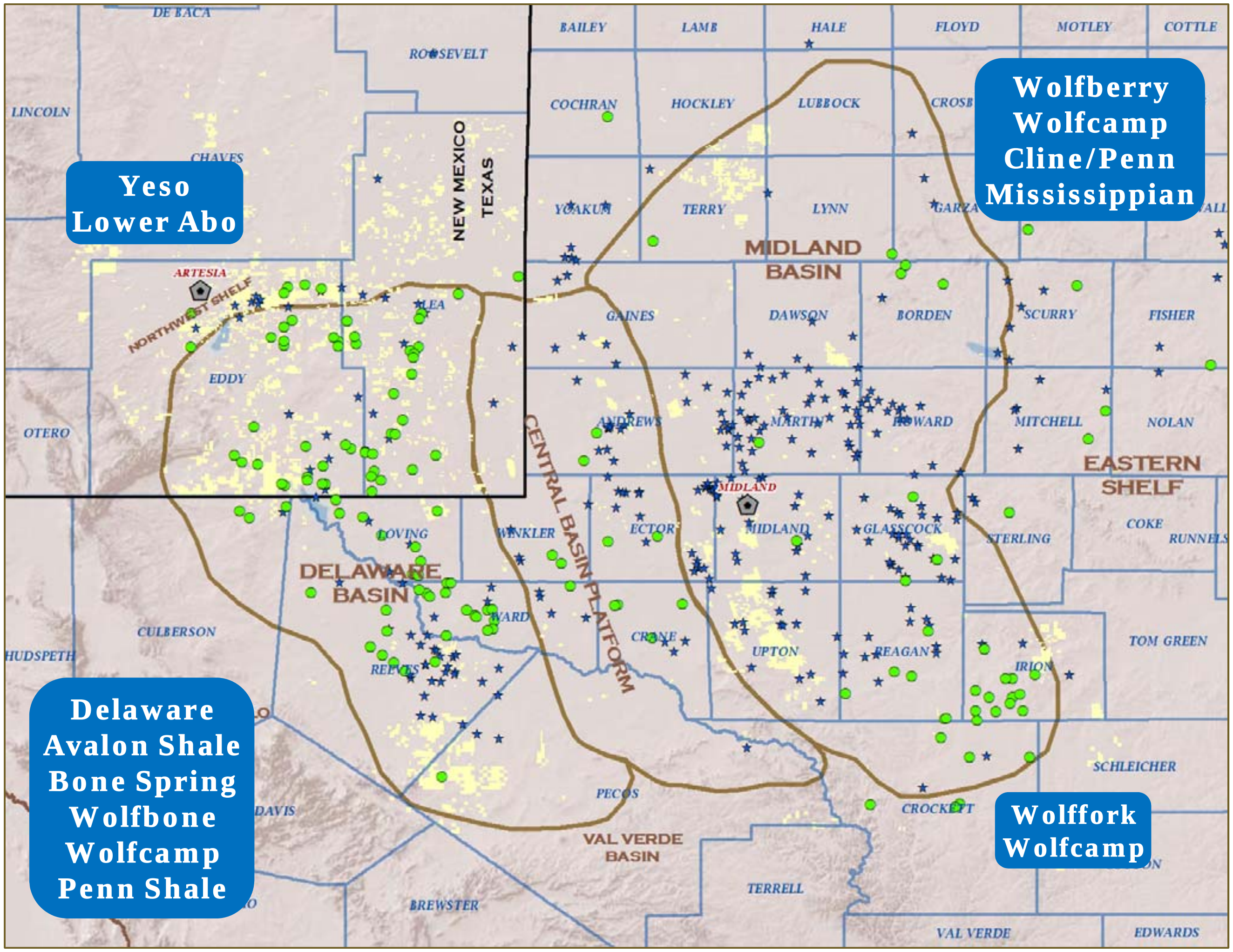
1 As of 12/31/11, adjusted to include 13 MMBoe of estimated proved reserves associated with 1Q12 Midland Basin acquisition and the 58 MMBoe of estimated proved reserves associated with the 3Q12 Three Rivers acquisition. Does not reflect impact of non-core asset sale which is expected to close in December 2012. See “Cautionary Statement Regarding Oil and Gas Quantities” for further discussion of estimation of proved reserves.

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 6/30/12, adjusted to include the impact of the 3Q12 Three Rivers acquisition.

Permian Basin Current Activity

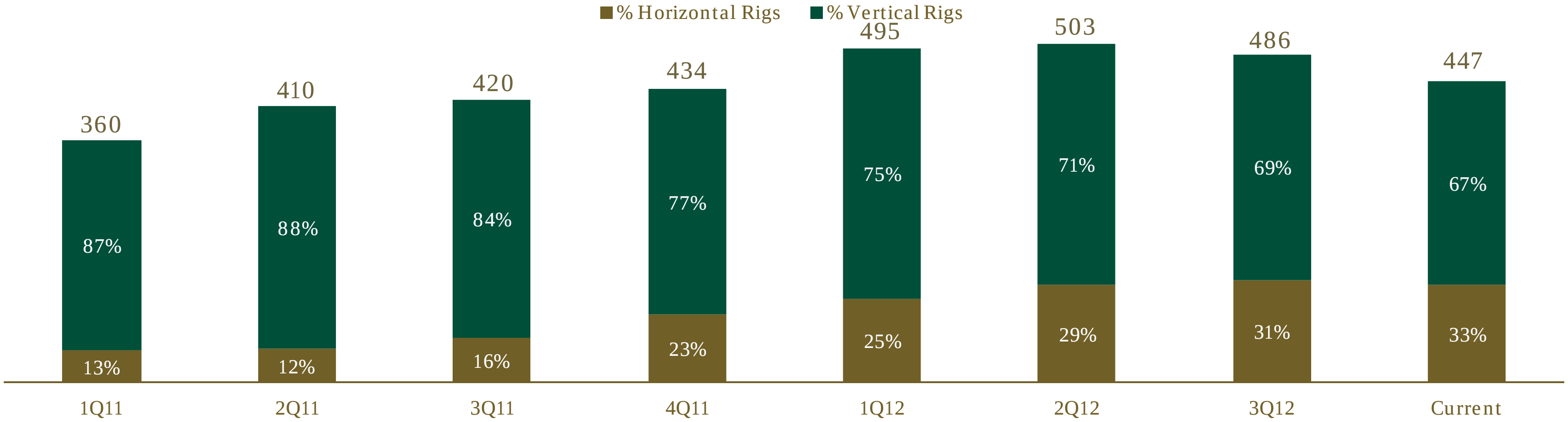
- Technology expanding resource potential across the Permian Basin
- Activity targeting unconventional reservoirs
- Approximately 447 rigs currently operating
  - 144 horizontal
- Increased activity driven by the emergence of new oil and liquids-rich plays
- Concho is uniquely positioned in the Permian with exposure to some of the most impactful existing and emerging plays



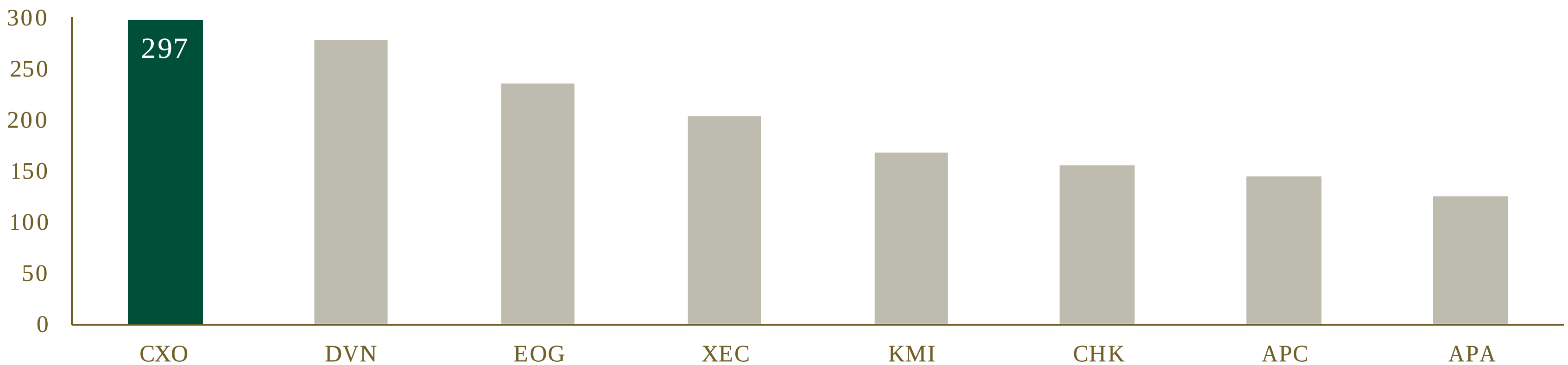
Concho Acreage ★ Vertical Rigs ● Horizontal Rigs

Source: PI Dwights, BHI.

Horizontal Rig Growth since 1Q11



Permian Horizontal Wells Drilled by Public Companies (2009 – 2012)



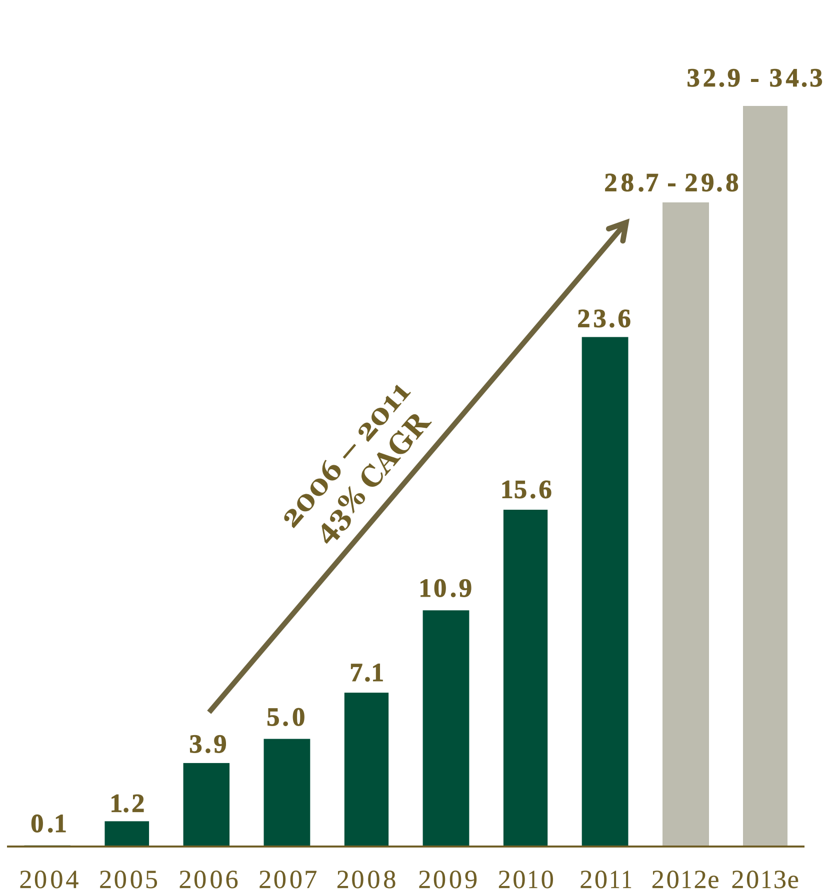
Source: IHS, BakerHughes, Smith Bits and Rig Data.

Operational Strategy

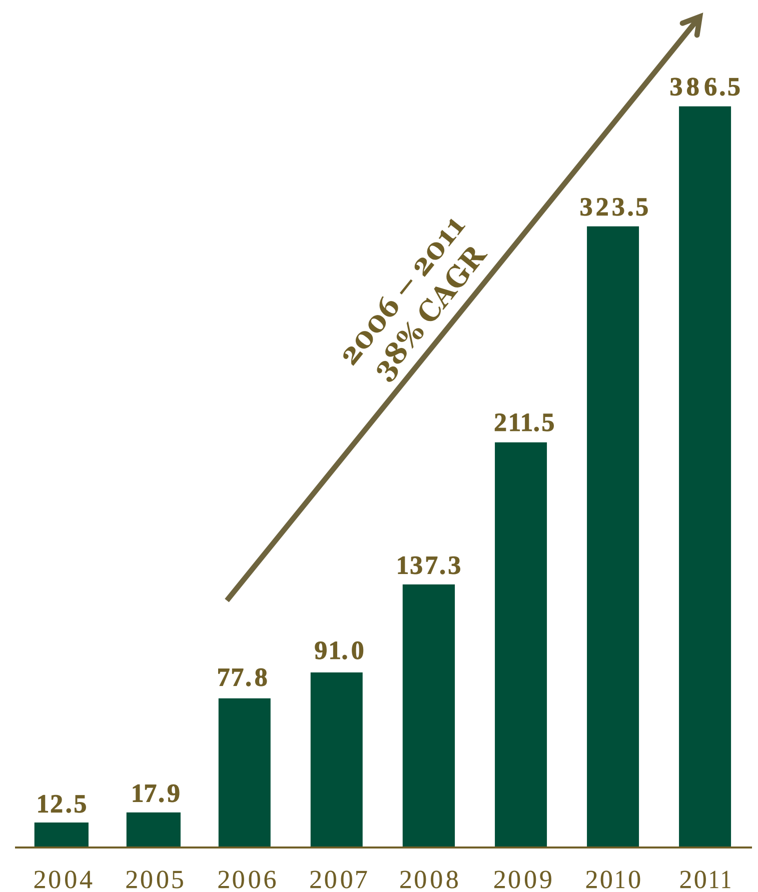
- Continued focus on the Permian Basin
  - Exposed to some of the most prolific oil plays in the U.S.
  - Capitalize on the strategic benefits of being one of the largest operators in the Permian Basin
- Committed to rate-of-return driven growth
  - Reinvest high-margin cash flows into projects with robust rates of return
  - Achieve superior per share growth rates while staying within cash flow
- Maintain simple, strong financial position
  - Conservative approach to leverage
  - Ample liquidity available under credit facility
  - 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

Track Record of Production & Reserve Growth

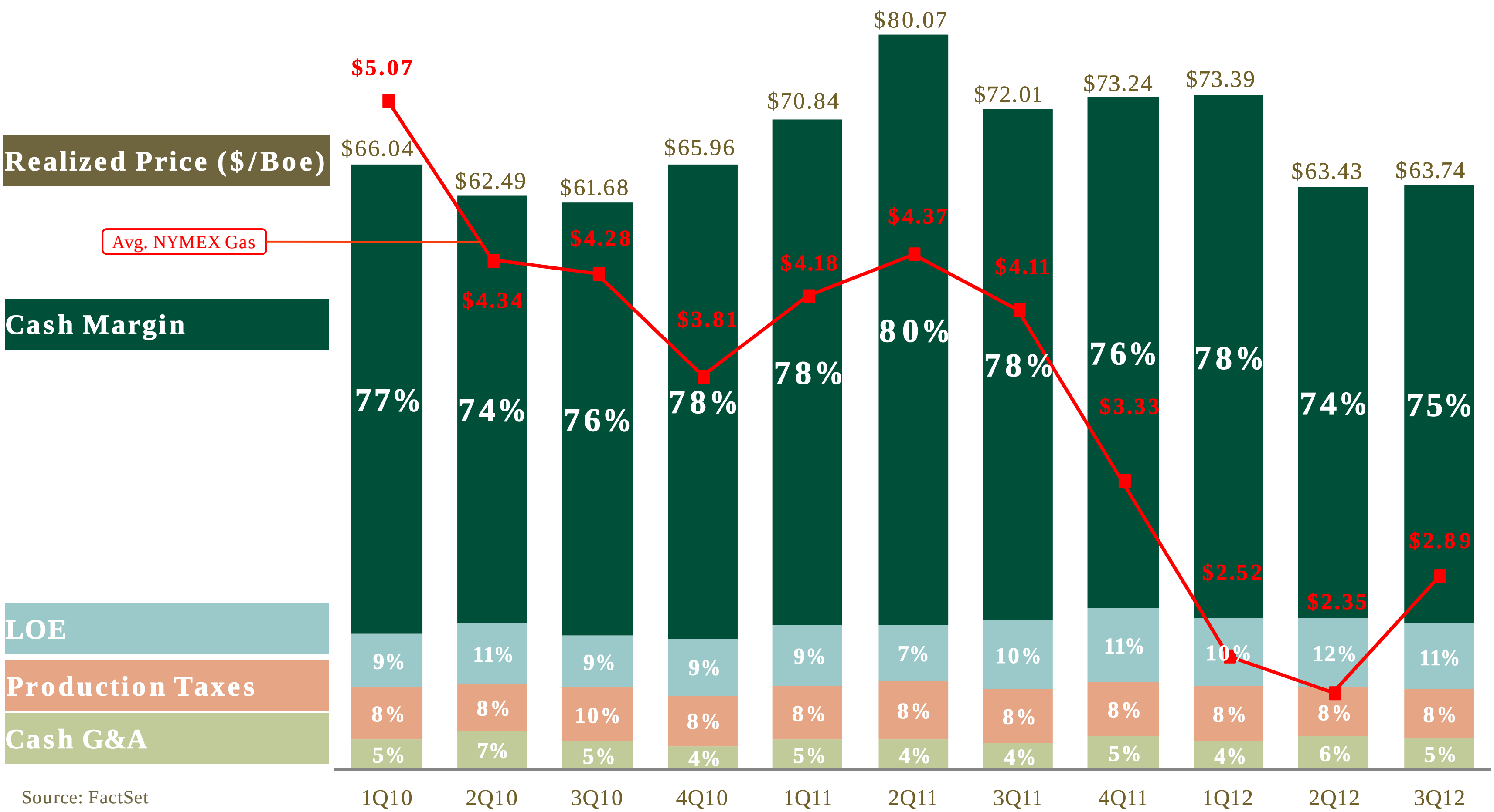
Annual Production (MMBoe)



Proved Reserves (MMBoe)



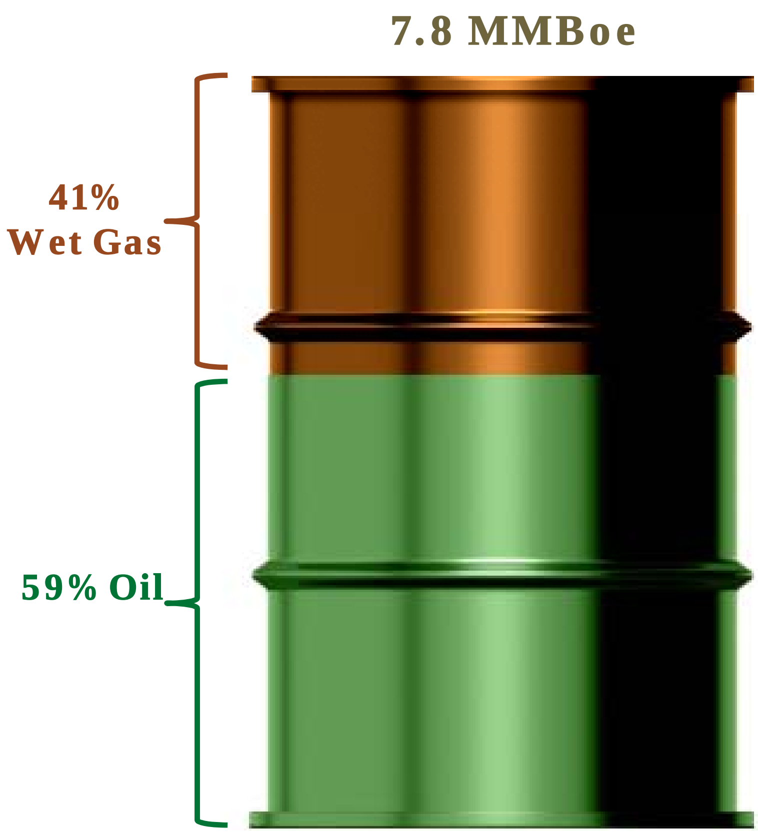
Unhedged Cash Margin Percentage[1] vs. Average NYMEX Natural Gas Price ($/MMbtu)



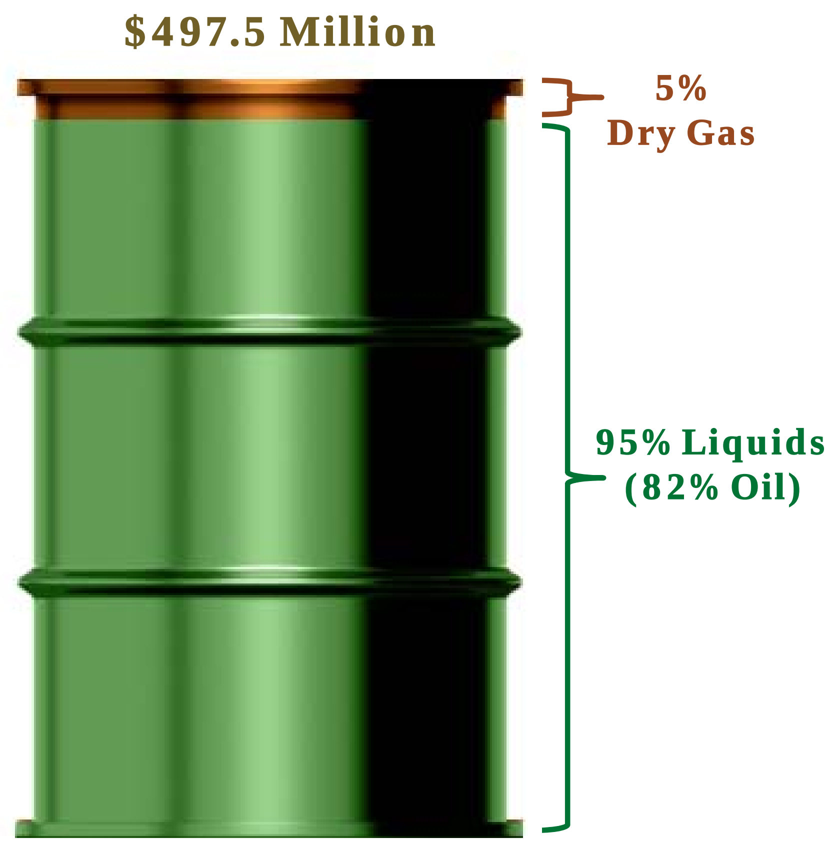
Source: FactSet

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. Percentages may not sum to 100% due to rounding.

3Q12 Production Mix

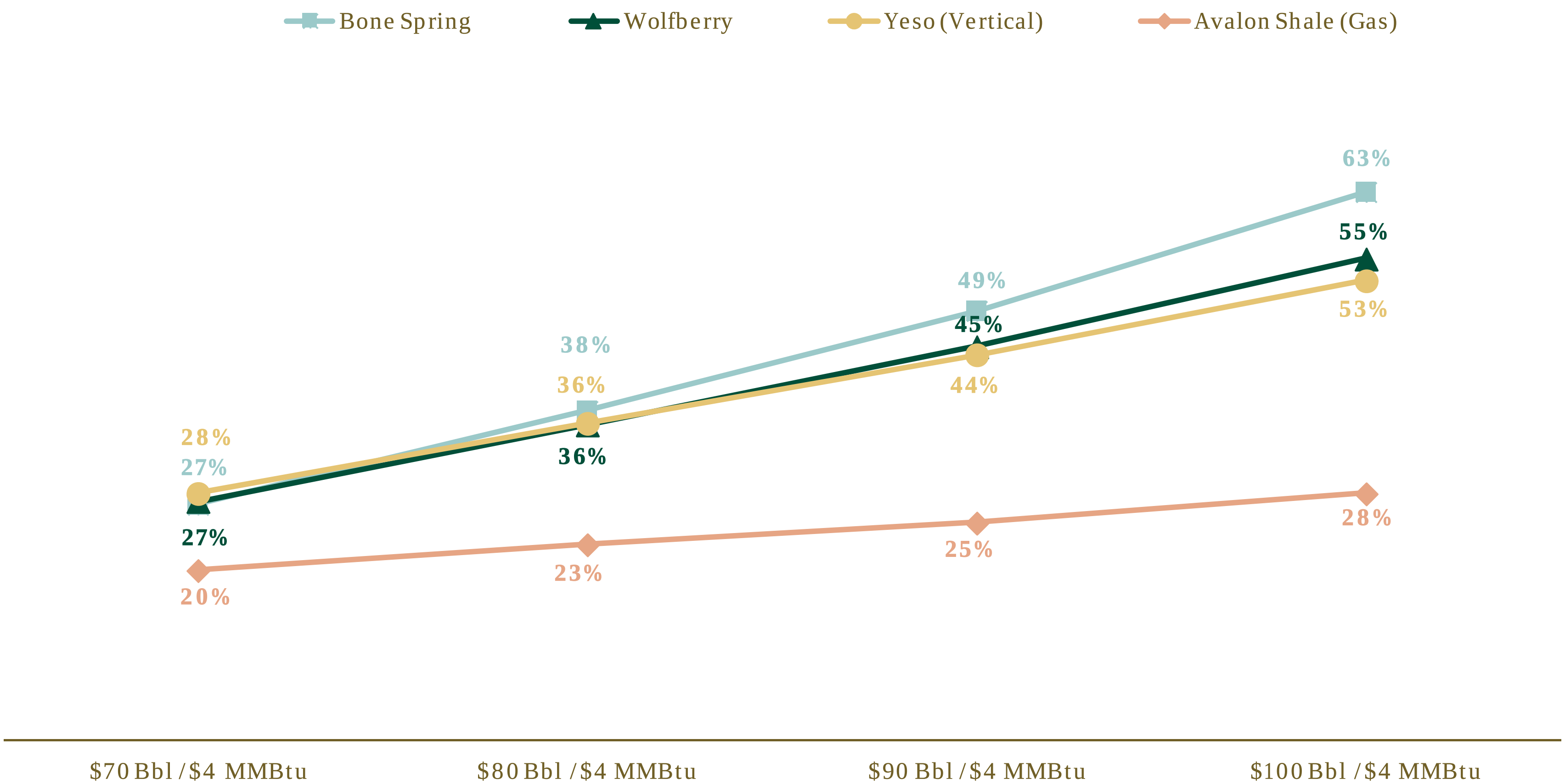


3Q12 Revenue Contribution



Reinvest High Margin Cash Flow into Robust ROR Projects

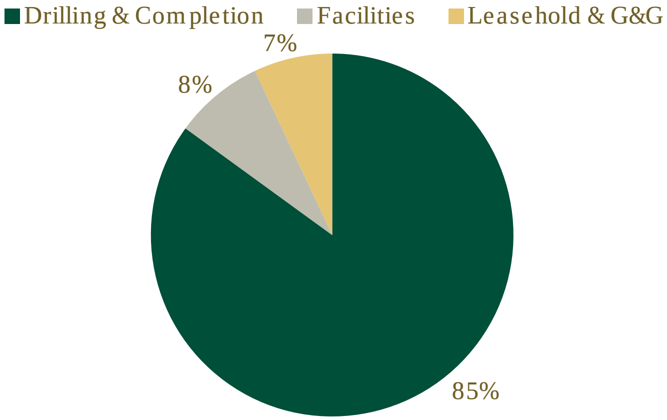
Inventory Rates of Return[1]



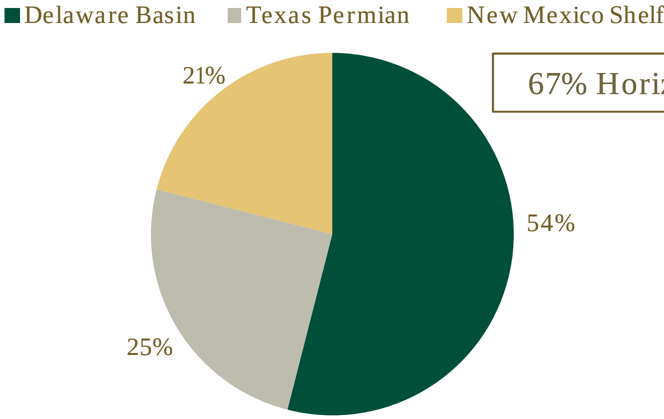
1 IRRs based on the aggregate economics of the total identified vertical Yeso, Wolfberry, Bone Spring sands and Avalon shale drilling locations at 6/30/2012 and current AFE's. Wolfberry aggregate model excludes 20-acre spaced drilling locations and shallow Wolfcamp locations. IRRs exclude interest, income taxes and G&A and do not take into account land cost or hedges. Includes inventory from 1Q12 Midland Basin acquisition and 3Q12 Three Rivers acquisition.

2013 Capital Budget and Activity

2013 Capital Budget: $1.6bn



2013 Drilling & Completion Budget: $1.4bn



67% Horizontal

New Mexico Shelf

- Average 5 rigs in 2013
  - 3 horizontal rigs
- Expect to drill ~190 wells in 2013
- 47% of proved reserves[1]
- 46% of production in 3Q12
- 2,470 drilling opportunities[2]
  - 1,559 Vertical Yeso
  - 369 Horizontal Yeso

Delaware Basin

- Average 11 rigs in in 2013
- Expect to drill ~175 wells in 2013
- 15% of proved reserves[1]
- 26% of production in 3Q12
- ~490,000 gross (329,000 net) acres[2]
- 2,375 Northern Delaware Basin drilling opportunities[2]

Texas Permian

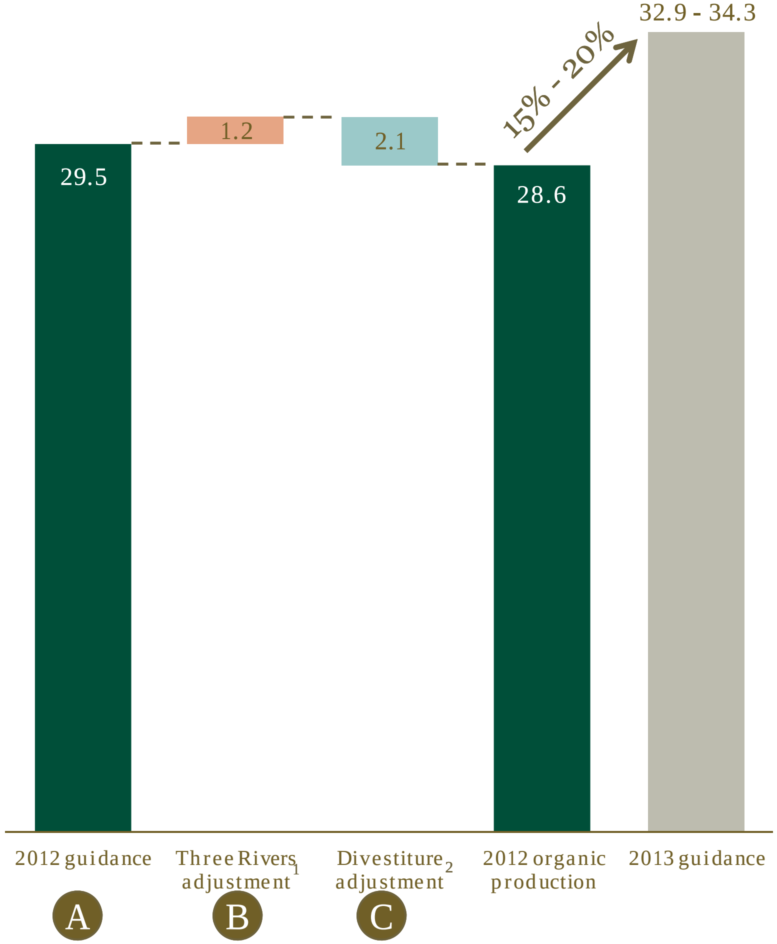
- Average 14 rigs in 2013
- Expect to drill ~265 wells in 2013
- 38% of proved reserves[1]
- 28% of production in 3Q12
- 5,772 drilling opportunities[2]
  - 2,064 40-acre Wolfberry
  - 2,629 20-acre Wolfberry
  - 927 shallow Wolfcamp

1 As of 12/31/11, adjusted to include 13 MMBoe of estimated proved reserves associated with 1Q12 Midland Basin acquisition and includes 58 MMBoe of estimated proved reserves associated with the 3Q12 Three Rivers acquisition. Does not reflect impact of non-core asset sale which is expected to close in December 2012.

2 As of 6/30/12, adjusted to include the impact of the 3Q12 Three Rivers acquisition.

2013 Organic Production Growth

Organic Production Reconciliation (MMBoe)



1 Three Rivers acquisition closed on July 2, 2012.
2 Divestiture of certain non-core assets is expected to close in December 2012.

A Top half of FY12 production guidance

- Includes 6 months of production from Three Rivers
- Includes 12 months of production from divested properties

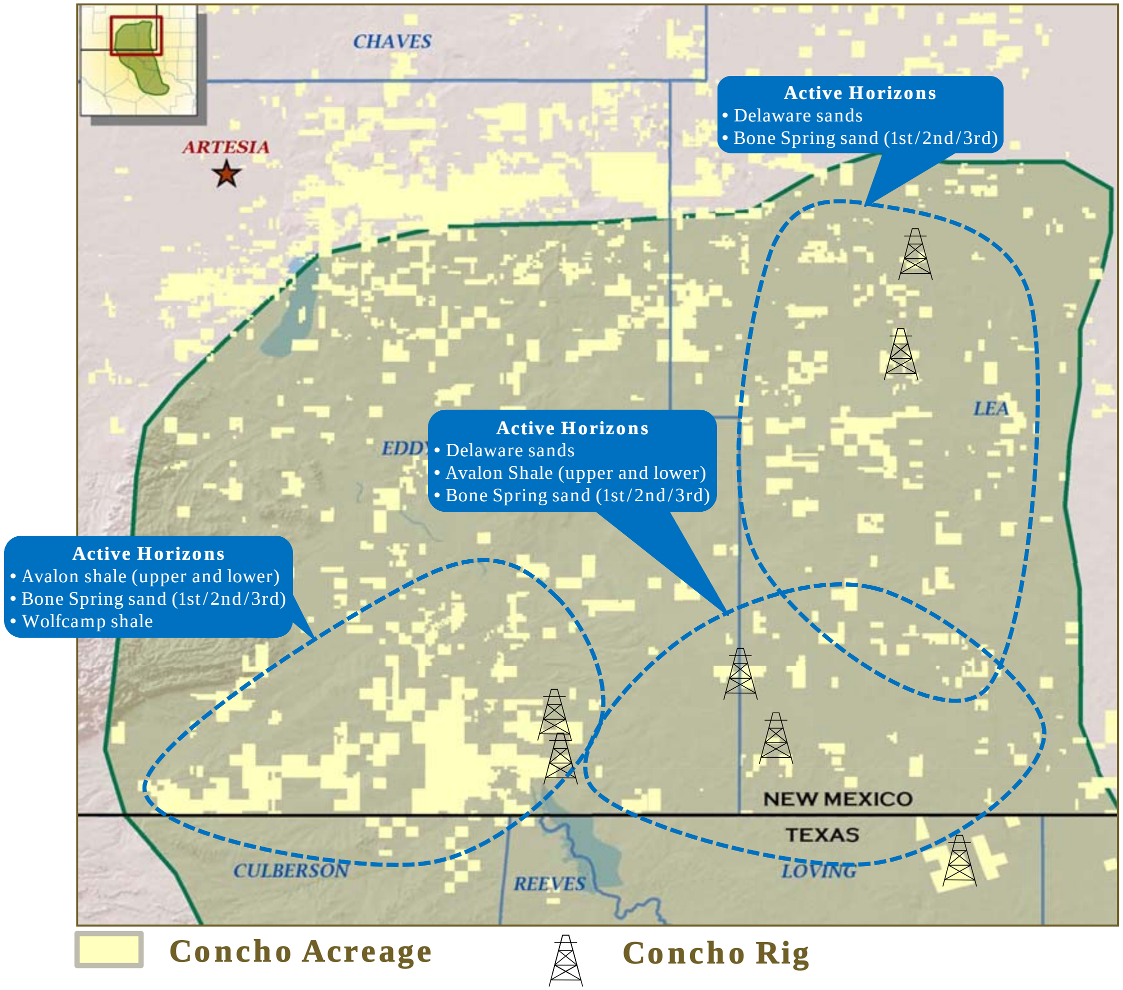
B Three Rivers adjustment

- Add 6 months of production from properties acquired from Three Rivers
- 3Q12A production from Three Rivers properties was approximately 6,700 Boepd

C Divestiture adjustment

- Exclude full year of production from divestiture properties
- 3Q12A production from divestiture properties was approximately 5,800 Boepd

Northern Delaware Basin



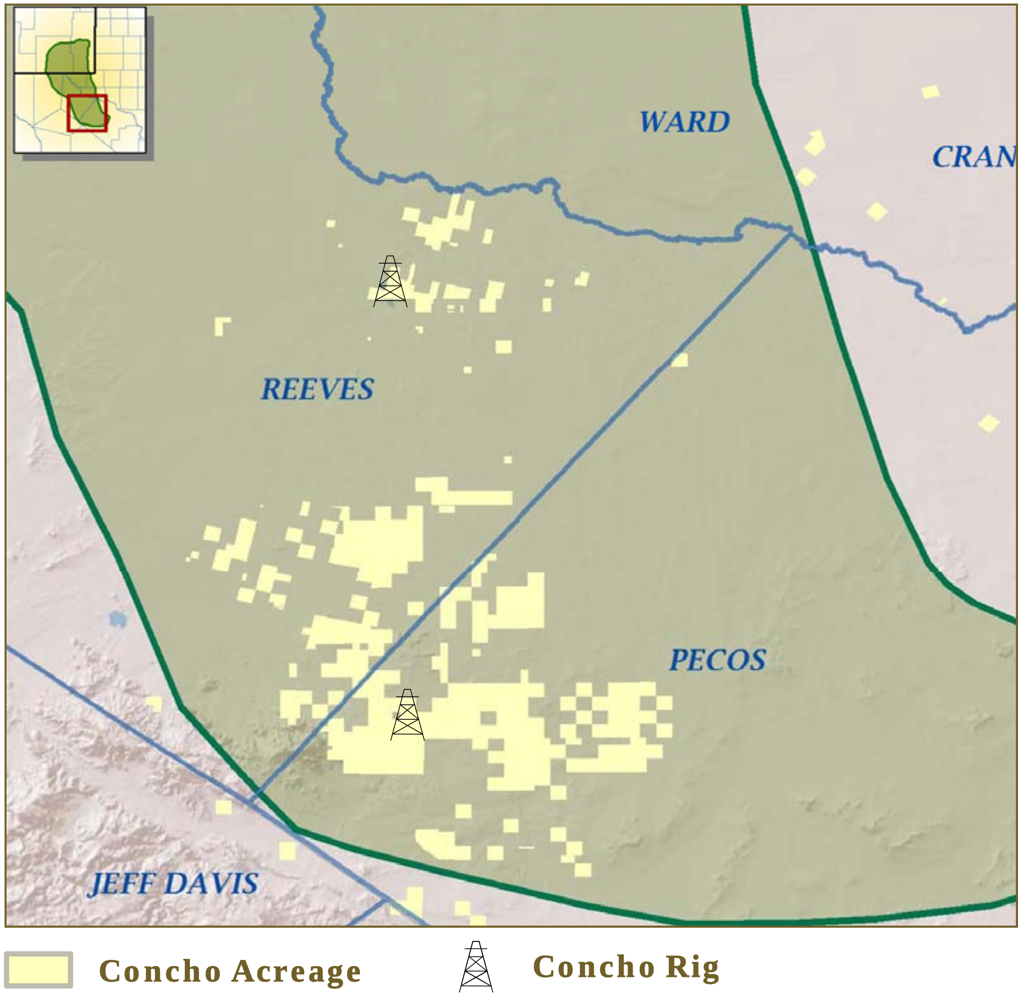
Overview

- 2,375[1] locations targeting:
  - Avalon shale
  - Bone Spring sands
  - Wolfcamp shale
- Other targets:
  - Delaware sands
  - Penn shale
- Significant progress in quantifying the stacked pay opportunity
  - 30% of locations identified as multi-zone

Well Characteristics

Drill and Complete	$5 - $9mm
EUR	300 - 700 MBoe
TVD	6,500' - 11,500'
Lateral Length	4,000' - 4,500'
Frac Stages	8 - 13
30 - Day IP	300 - 1,500 Boepd

1 As of 6/30/12, adjusted to include the impact of the 3Q12 Three Rivers acquisition.



Overview

- ~140,000 gross (125,000 net) acre position[1]
- Target horizons:
  - Delaware sands
  - Avalon shale
  - Bone Spring sands
  - Wolfcamp shale
- Encouraging early production
  - Four wells completed with 30 days of production data
  - Average 30-day IP: 675 Boepd (84% oil)
- Active drilling program
  - 10 wells in 2012
  - 1-2 rigs in 2013
  - Continue to delineate productive play extents in Reeves and Pecos Counties

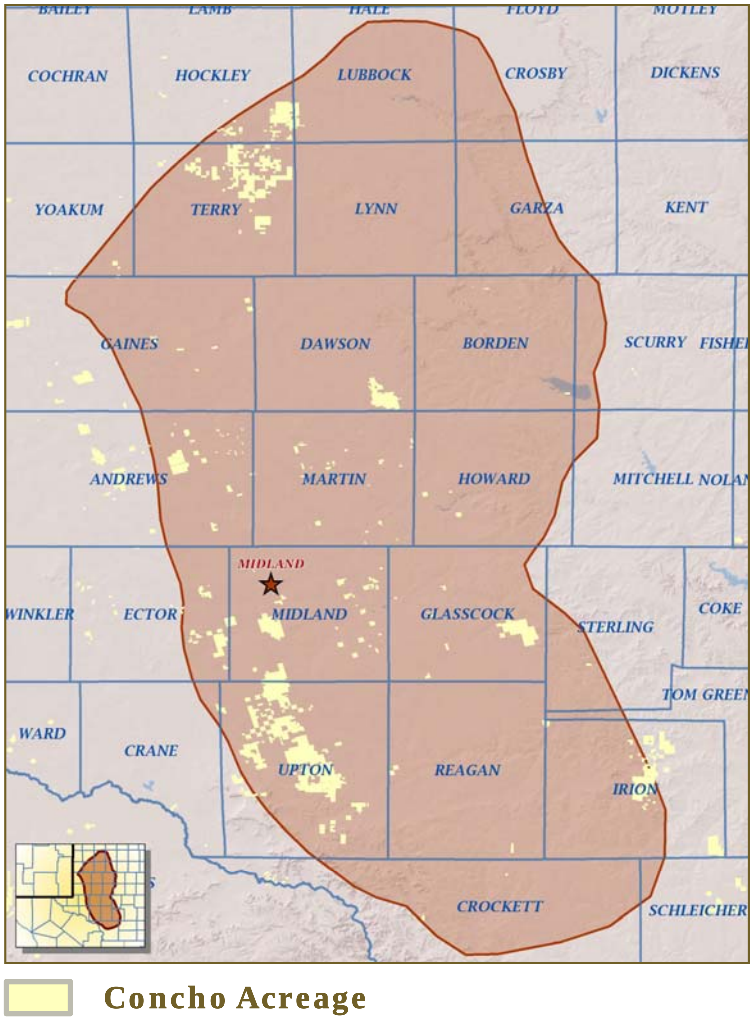
1 As of 6/30/12, adjusted to include the impact of the 3Q12 Three Rivers acquisition.

Wolfberry Play

- Technical team has drilled over 1,000 wells
- Have added over 500 Wolfberry locations through acquisitions in 2012
- Continue to test opportunities in eastern Midland Basin

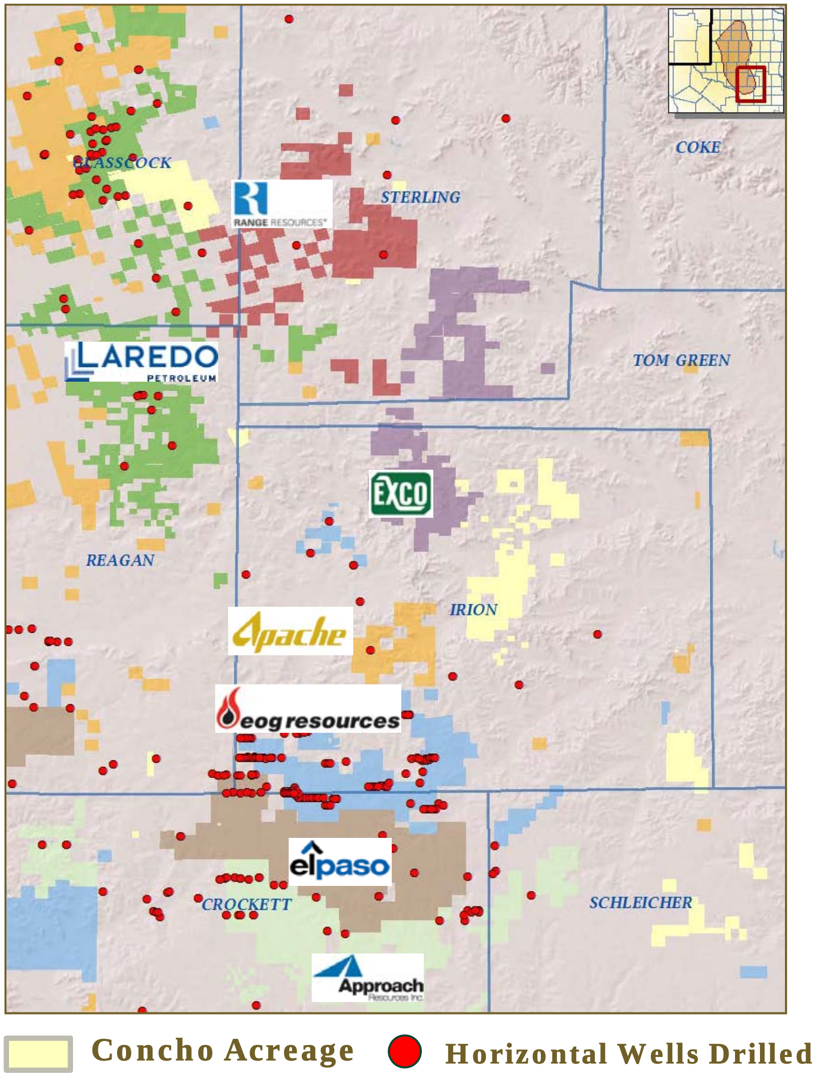
Horizontal Activity

- Drilled 2 horizontal Cline wells in Glasscock County
- Ongoing horizontal Wolfcamp test in core Wolfberry play
  - Drilled 2 horizontal Wolfcamp wells in Upton County
  - Will test areas targeted for vertical 20-acre Wolfberry development
- Drilled one horizontal well in Terry County
  - Second well planned for 4Q12



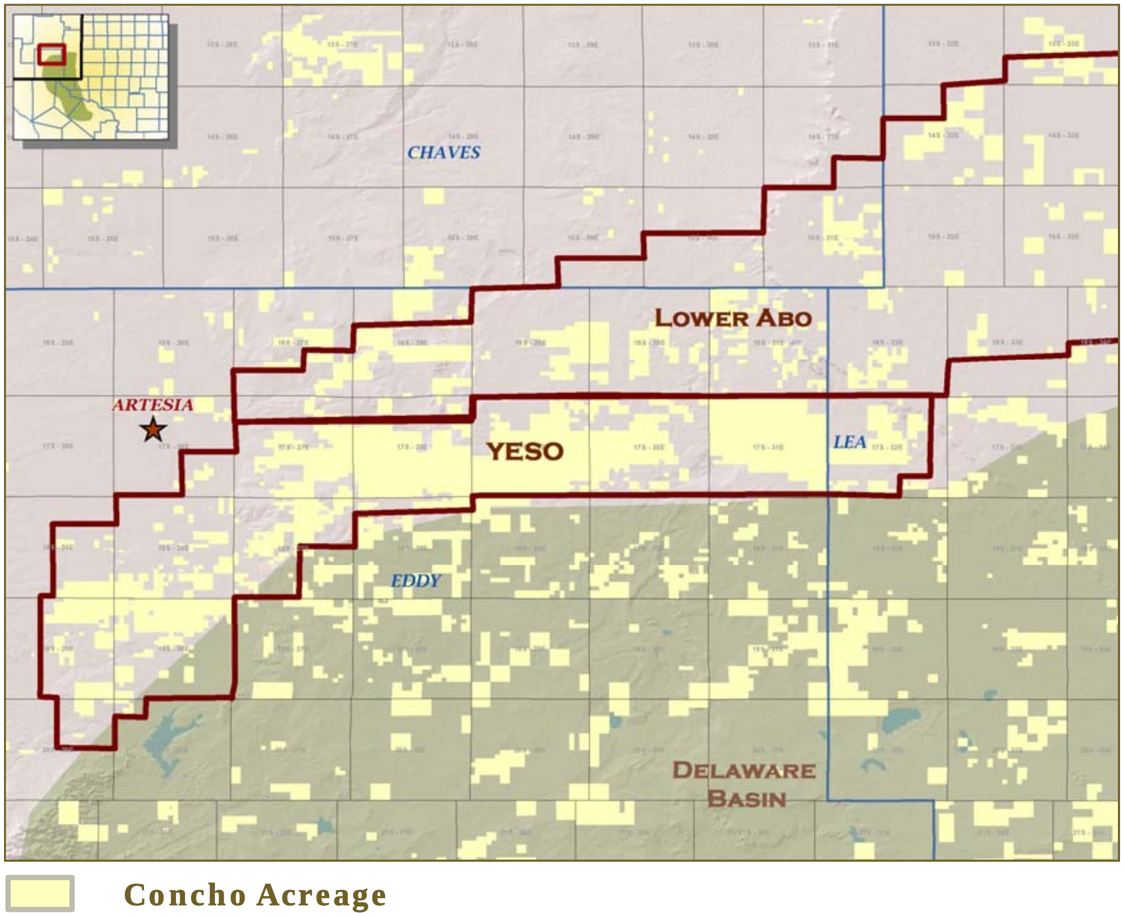
Southern Midland

- Expanded position in through acquisition of assets from Three Rivers
  - Acquired 39,700 gross (29,000 net) acres
- Industry ramping up horizontal development across the area
  - Strong industry results to the south and west of Irion acreage position
  - Targets include upper, middle and lower Wolfcamp
  - Cline shale offers multi-zone potential
- Irion County position exclusively developed vertically targeting shallow Wolfcamp
- Currently drilling the first horizontal well on Irion County acreage targeting upper Wolfcamp
  - Expect to drill additional horizontal wells in 2013



Shelf Overview

- Will average 5 rigs in 2013
  - 3 Horizontal Yeso rigs
  - 2 Vertical Yeso rigs
- Concho has drilled over 1,000 wells in the Yeso
- Expanding the play boundary through horizontal development
  - Potential to add to existing horizontal Yeso inventory
- Drilled 30 horizontal Yeso wells year to date
  - EUR: 300 – 350 MBoe
  - D&C: \$3 – \$4mm
  - IRR: >40%[1]
- Plan to drill ~60 horizontal Yeso well in 2013



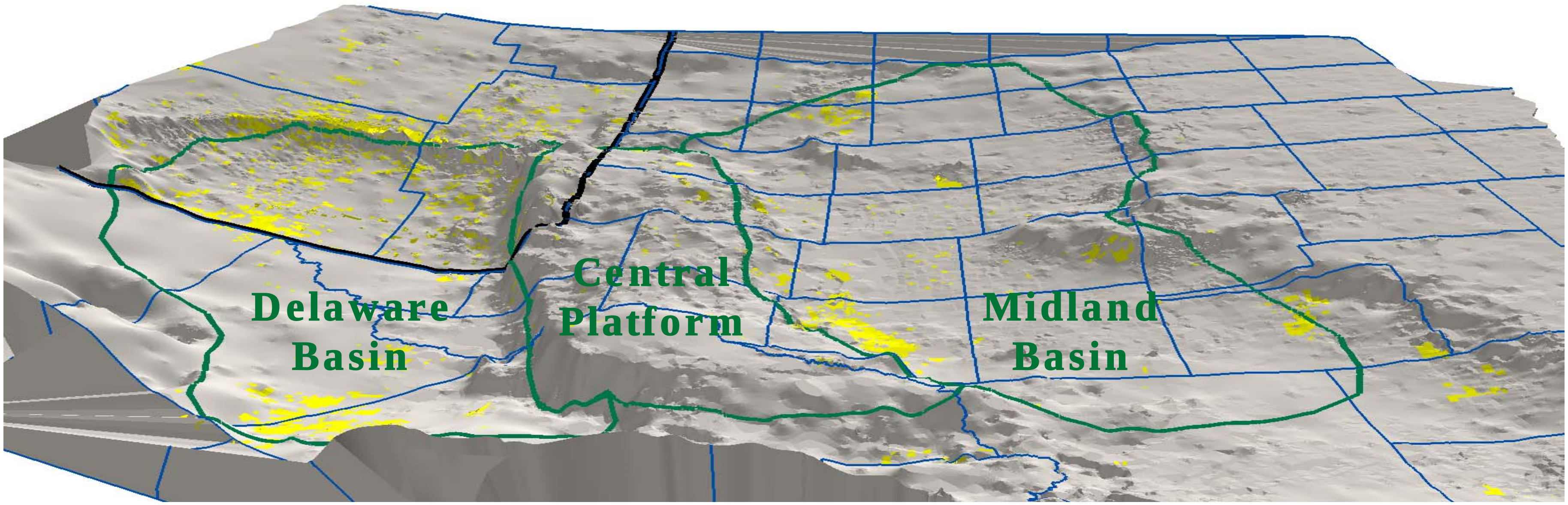
1 Assumes \$85.00/Bbl and \$4.00/Mcf.

- 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 10,600 drilling locations[1]
- 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 6/30/12, adjusted to include the impact of the 3Q12 Three Rivers acquisition.

Appendix

Permian Basin – Base of the Wolfcamp

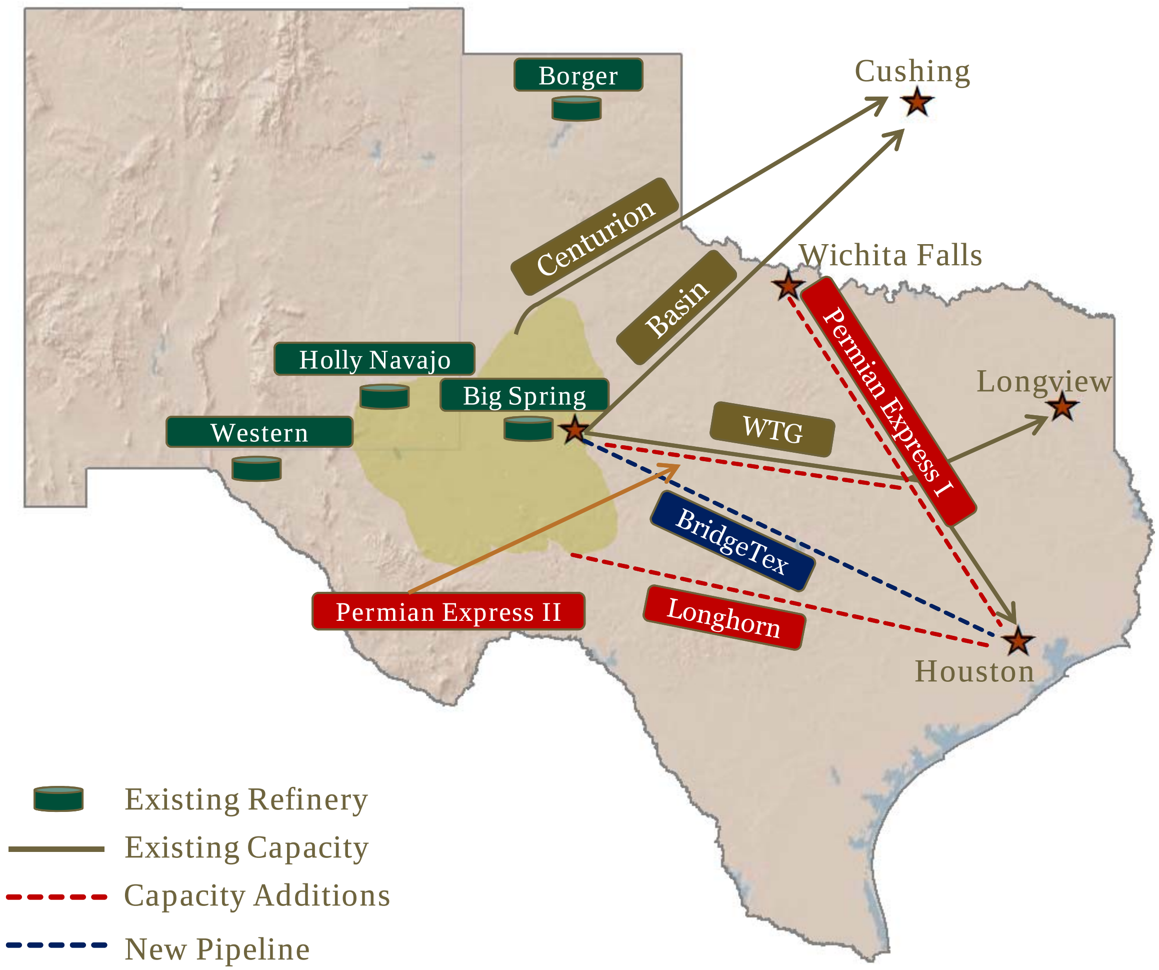


PERIOD	SERIES	DELAWARE BASIN FORMATION
GUADALUPE	DELAWARE GROUP	LAMAR BELL CANYON
GUADALUPE	DELAWARE GROUP	CHERRY CANYON
GUADALUPE	DELAWARE GROUP	BRUSHY CANYON
LEONARD		UPPER AVALON SHALE
LEONARD		LOWER AVALON SHALE
LEONARD		1ST BONE SPRING
LEONARD		2ND BONE SPRING
LEONARD		3RD BONE SPRING
WOLFCAMP		WOLFCAMP
PENN		PENNSYLVANIAN

PERIOD	SERIES	CENTRAL PLATFORM FORMATION
GUADALUPE	WHITE-HORSE	TANSILL
GUADALUPE	WHITE-HORSE	YATES
GUADALUPE	WHITE-HORSE	7 RIVERS
GUADALUPE	WHITE-HORSE	QUEEN
GUADALUPE	WHITE-HORSE	GRAYBURG
GUADALUPE	WARD	SAN ANDRES
GUADALUPE	WARD	GLORIETA
LEONARD	YESO	PADDOCK
LEONARD	YESO	BLINEBRY
LEONARD	YESO	TUBB
LEONARD	YESO	DRINKARD
LEONARD		ABO
WOLFCAMP	WOLFCAMP	HUECO
WOLFCAMP	WOLFCAMP	BURSUM
PENN		PENNSYLVANIAN

PERIOD	SERIES	MIDLAND BASIN FORMATION
GUADALUPE	WHITE-HORSE	TANSILL
GUADALUPE	WHITE-HORSE	YATES
GUADALUPE	WHITE-HORSE	7 RIVERS
GUADALUPE	WHITE-HORSE	QUEEN
GUADALUPE	WHITE-HORSE	GRAYBURG
GUADALUPE	WARD	SAN ANDRES
GUADALUPE	WARD	GLORIETA
LEONARD	CLEAR FORK	UPPER LEONARD
LEONARD		UPPER SPRABERRY
LEONARD		LOWER SPRABERRY
LEONARD		DEAN
WOLFCAMP		WOLFCAMP
PENN		PENNSYLVANIAN

Permian Basin – Oil Takeaway Capacity



Existing Takeaway

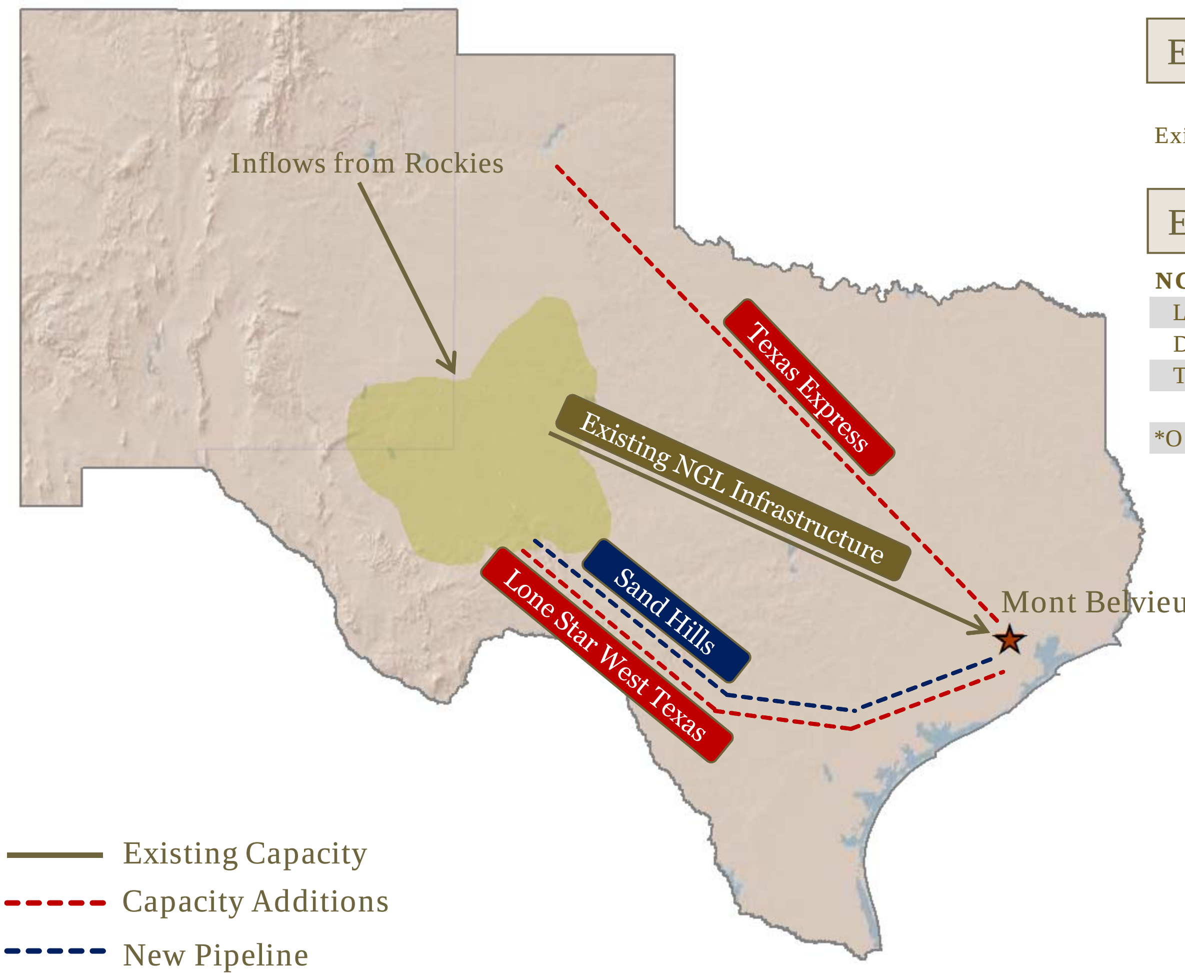
Refineries	MBopd
Big Spring	70
Holly Frontier Navajo	100
Borger Refinery (net from Permian)	115
Western	125
Total	**410**

Oil Pipelines	MBopd
Basin Pipeline (PAA)	450
Centurion Pipeline (OXY)	100
Sunoco WTG Pipeline	220
Total	**770**

Expansion Capacity

Oil Expansions	Completion Date	MBopd
Magellan		
Longhorn Reversal (Phase I)	1Q13	75
Longhorn Reversal (Phase II)	2Q13	150
BridgeTex Crude Oil Pipeline	2Q14	278
Sunoco		
Permian Express I	1Q13	90
Permian Express II	3Q14	200
Total		**793**

Permian Basin – NGL Takeaway Capacity



Existing Takeaway

	MBblpd
Existing NGL Infrastructure	707

Expansion Capacity

NGL Expansions	Completion Date	MBblpd
Lone Star West Texas Pipeline	1Q13	210
DCP Sand Hills NGL Pipeline	2Q13	250
Texas Express NGL Pipeline*	3Q13	280
		740

*Originates in the Texas Panhandle

EBITDAX Reconciliation

Historical EBITDAX

(in thousands)	Year Ended December 31, 2011	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income	$ 548,137	$ 5,988	$ 356,205	$ 356,402	$ 630,962
Exploration and abandonments	11,779	6,958	3,498	27,335	4,624
Depreciation, depletion and amortization	428,377	157,621	115,730	434,940	304,899
Accretion of discount on asset retirement obligations	2,965	1,420	751	3,455	2,170
Impairments of long-lived assets	439	-	-	-	76
Non-cash stock-based compensation	19,271	7,959	4,673	21,434	13,866
Unrealized (gain) loss on derivatives not designated as hedges	(61,504)	151,554	(387,010)	(117,027)	(374,797)
Loss on sale of assets, net	1,139	217	1,674	285	3,129
Interest expense	118,360	51,337	32,881	129,073	84,201
Income tax expense on continuing operations	285,848	4,155	221,199	220,835	334,000
Discontinued operations	(79,652)	-	-	-	(83,306)
EBITDAX	$ 1,275,159	$ 387,209	$ 349,601	$1,076,732	$ 919,824

We define EBITDAX as net income (loss), 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) unrealized (gain) loss on derivatives not designated as hedges, (7) loss on sale of assets, net (8) interest expense, (9) federal and state income taxes on continuing operations and (10) 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.

CONCHO

Adjusted Net Income Reconciliation

Historical Adjusted Net Income

(in thousands, except per share amounts)	Year Ended December 31, 2011	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011
Net income - as reported	$ 548,137	$ 5,988	$ 356,205
Adjustments for certain non-cash items:			
Unrealized (gain) loss on commodity and interest rate derivatives	(61,504)	151,554	(387,010)
Impairments of long-lived assets	439	-	-
Leasehold abandonments	5,735	677	639
Discontinued operations:			
Gain on sale of assets	(135,943)	-	-
Tax impact (a)	73,258	(58,457)	147,980
Adjusted net income	$ 430,122	$ 99,762	$ 117,814
Adjusted basic earnings per share:			
Adjusted net income per share	$ 4.19	$ 0.97	$ 1.15
Weighted average shares used in adjusted basic earnings per share	102,581	103,292	102,733
Adjusted diluted earnings per share:			
Adjusted net income per share	$ 4.15	$ 0.96	$ 1.14
Weighted average shares used in adjusted diluted earnings per share	103,653	104,040	103,696

(a) The tax impact is computed utilizing the Company's adjusted statutory effective federal and state income tax rates. The income tax rates were 38.3% for the year ended December 31, 2011 and 38.4% and 38.3% for each of the three months ended September 30, 2012 and 2011, respectively.

Unhedged Cash Margin Reconciliation

Historical Unhedged Cash Margin

($ in thousands, except per unit data)	1Q10	2Q10	3Q10	4Q10	1Q11	2Q11	3Q11	4Q11	1Q12	2Q12	3Q12
Net income (loss)	$ 67,540	$ 124,171	$ 20,775	$ (8,116)	$ 42,575	$ 232,182	$ 356,205	$ (82,825)	$ 31,117	$ 319,297	$ 5,988
Exploration and abandonments	1,109	922	3,617	4,676	726	400	3,498	7,155	5,979	14,398	6,958
Depreciation, depletion and amortization	50,159	49,611	57,624	84,248	90,288	98,881	115,730	123,478	135,869	141,450	157,621
Accretion of discount on asset retirement obligations	341	316	349	476	704	715	751	795	988	1,047	1,420
Impairments of long-lived assets	256	3,489	1,922	5,947	-	76	-	363	-	-	-
Non-cash stock-based compensation	2,831	2,871	3,152	4,077	4,468	4,725	4,673	5,405	6,128	7,347	7,959
(Gain) loss on derivatives not designated as hedges	(15,573)	(112,763)	66,107	149,554	233,142	(144,882)	(385,222)	320,312	158,093	(403,050)	135,415
Interest expense	11,065	11,192	12,036	25,794	29,660	21,660	32,881	34,159	35,837	41,899	51,337
Other (income) expense, net	73	304	3,521	6,415	352	1,735	2,503	(616)	1,268	535	3,114
Income tax expense (benefit)	38,763	72,220	7,392	(3,097)	(30,469)	143,270	221,199	(48,152)	19,117	197,563	4,155
Discontinued operations (a)	7,470	8,229	7,030	(11,927)	(83,306)	-	-	3,654	-	-	-
Unhedged Cash Margin	$ 164,034	$ 160,562	$ 183,525	$ 258,047	$ 288,140	$ 358,762	$ 352,218	$ 363,728	$ 394,396	$ 320,486	$ 373,967
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	6,919 MBoe	6,823 MBoe	7,806 MBoe
Unhedged Cash Margin ($/Boe)	$ 51.10	$ 46.51	$ 47.07	$ 51.59	$ 55.11	$ 64.38	$ 55.81	$ 55.68	$ 57.00	$ 46.97	$ 47.91
Average price without derivatives ($ /Boe)	$ 66.04	$ 62.49	$ 61.68	$ 65.96	$ 70.84	$ 80.07	$ 72.01	$ 73.24	$ 73.39	$ 63.43	$ 63.74
Unhedged Cash Margin (%)	77%	74%	76%	78%	78%	80%	78%	76%	78%	74%	75%

Unhedged cash margin per BOE (as calculated 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 that is presented in discontinued operations.

Hedges as of 11/7/2012

Current Oil and Natural Gas Swaps

	4Q 2012	2013	2014	2015	2016	2017
Oil Swaps						
Volume (Bbl)	4,151,500	13,330,000	7,283,000	1,076,000	429,000	168,000
NYMEX price (Bbl) (a)	$ 96.01	$ 95.77	$ 91.93	$ 86.69	$ 88.31	$ 87.00
Natural Gas Swaps						
Volume (MMBtu)	75,000	-	-	-	-	-
NYMEX price (MMBtu) (b)	$ 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.

Concho 2013 Production and Operating Guidance

Production:	
Oil equivalent (MMBoe)	32.9 - 34.3
% Oil	60% - 62%
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)	$7.50 - $8.00
Oil & natural gas taxes (% of oil and natural gas revenu	8.25%
G&A expense:	
Cash G&A expense ($/Boe)	$3.25 - $3.75
Non-cash stock based compensation ($/Boe)	$1.10 - $1.20
DD&A expense ($/Boe)	$20.00 - $22.00
Exploration, abandonments and G&G ($/Boe)	$1.50 - $2.50
Cash interest rates:	
$300 million senior notes due 2017	8.63%
$600 million senior notes due 2021	7.00%
$600 million senior notes due 2022	6.50%
$600 million senior notes due 2022	5.50%
$700 million senior notes due 2023	5.50%
Remainder of debt	LIBOR + (150 - 250 bps)
Non-cash interest expense ($ in millions)	$13.5 - $15.5
Income taxes:	38%
Percent deferred of total taxes	75% - 85%
Capital expenditures ($ in billions)	$1.6