October 2013

October Investor Presentation

Forward-Looking Statements and Other Disclaimers

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 fact, included in this presentation that address activities, events or developments that Concho Resources Inc. (the "Company") expects, believes or anticipates will or may occur in the future, including, among others, the Company's operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing, are forward-looking statements. The words "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" 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. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may 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 Annual Report on Form 10-K and our subsequent filings with the U.S. Securities and Exchange Commission ("SEC") and risks relating to declines in the prices we receive for our oil and natural gas; uncertainties about the estimated quantities of oil and natural gas reserves; drilling and operating risks, including risks related to properties where we do not serve as the operator and risks related to hydraulic fracturing activities; the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility; the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing; 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; shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel; potential financial losses or earnings reductions from our commodity price management program; 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; competition in the oil and natural gas industry; uncertainty concerning our assumed or possible future results of operations 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, and we caution you not to rely on them unduly.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP") including EBITDAX, adjusted net income and unhedged 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.

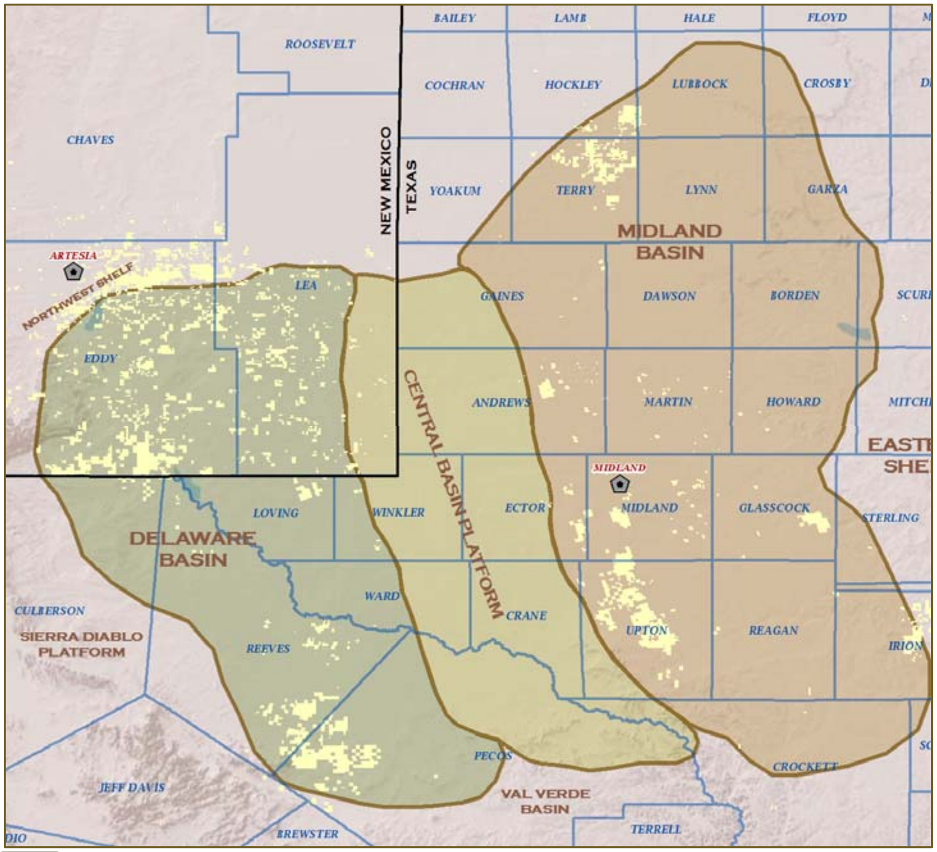
The SEC requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date 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, 2012 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $91.21 per Bbl of oil and $2.76 per MMBtu of natural gas. The Company's estimate of its total proved reserves at December 31, 2012 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 natural 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
- 447 MMBoe year-end 2012 estimated proved reserves[1]
  - 422% reserve replacement ratio[2]
- Results in 2Q 2013:
  - Drilled 196 gross wells
  - Produced 8.3 MMBoe
  - Net income of $84.7mm
  - EBITDAX[3] (non-GAAP) of $424.8mm
  - Adjusted net income[3] (non-GAAP) of $102.5mm
- Approximately 1.2mm gross (630,000 net) acres[4]
- Deep inventory of robust rate-of-return drilling opportunities
- Currently operating 22 rigs
  - 17 rigs drilling horizontally

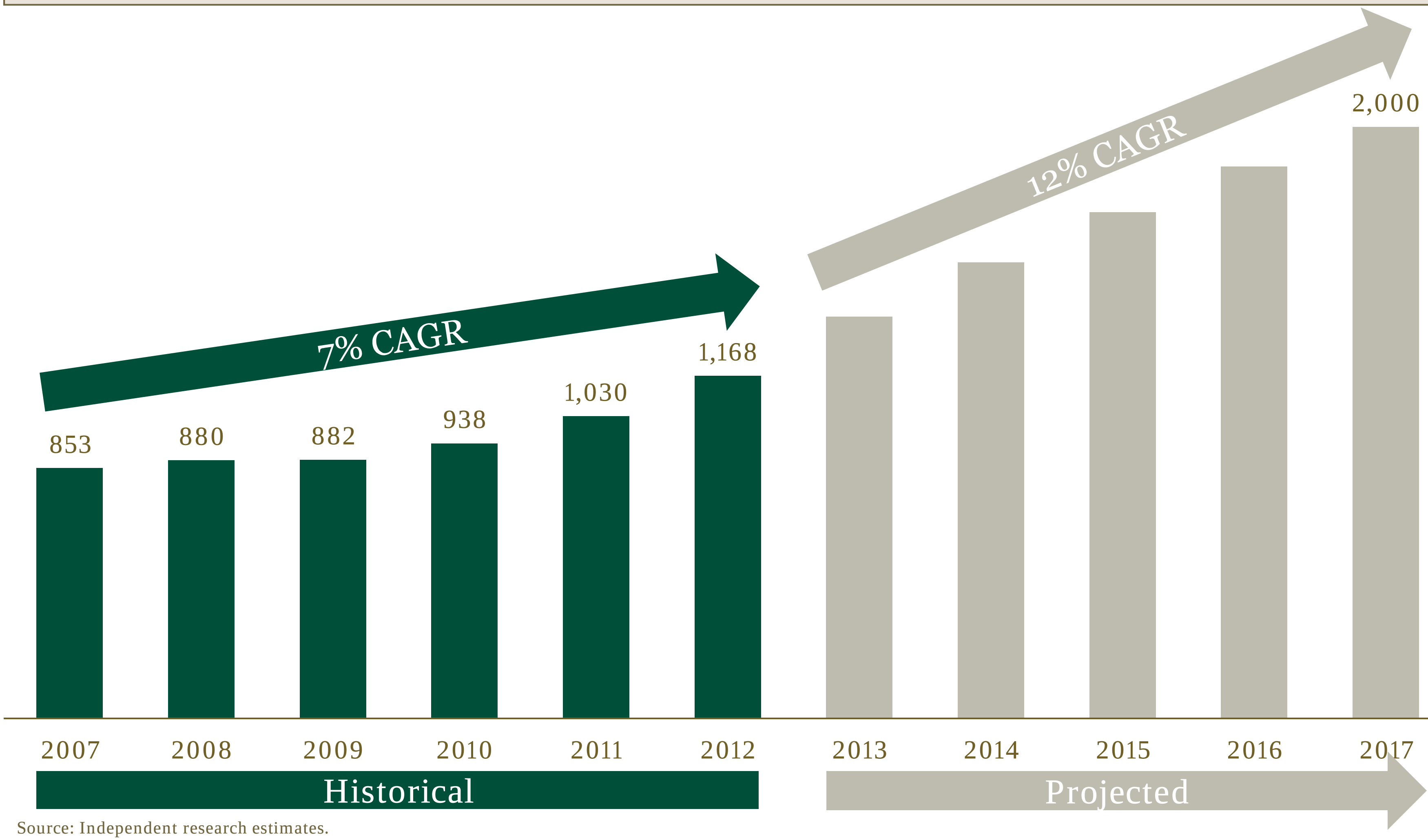
Permian Basin



Concho Acreage

1 See “Forward-Looking Statements and Other Disclaimers” for further discussion of estimation of proved reserves.
2 The reserve replacement ratio of 422% was calculated by dividing net proved reserve additions of 125.7 MMBoe (the sum of extensions, discoveries, revisions and purchases) by production of 29.8 MMBoe.
3 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.
4 As of 12/31/12.

Total Permian Basin Oil Production (MBopd)



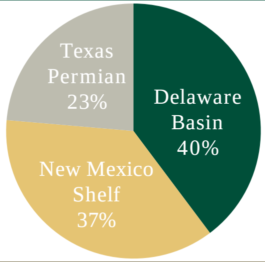
Source: Independent research estimates.

What's New?

2Q13 Accomplishments

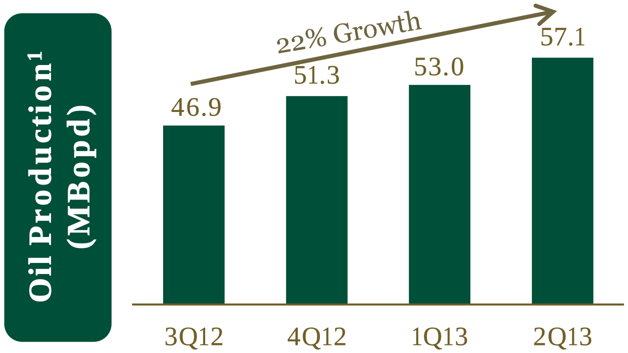
- Cash margin returned to historic strength
- Two significant Delaware Basin milestones achieved:
  - Delaware Basin now the largest producing core area
  - Horizontal Delaware Basin production grew 37% over 1Q13
- Completed a record number of horizontal wells (58) across all assets

2Q13 Production



Continued Crude Oil Growth

- Oil mix increased to 63% of total production
  - Highest level in 2 years
- Daily oil production +22% over last 4 quarters
- Horizontal Delaware Basin driving oil growth



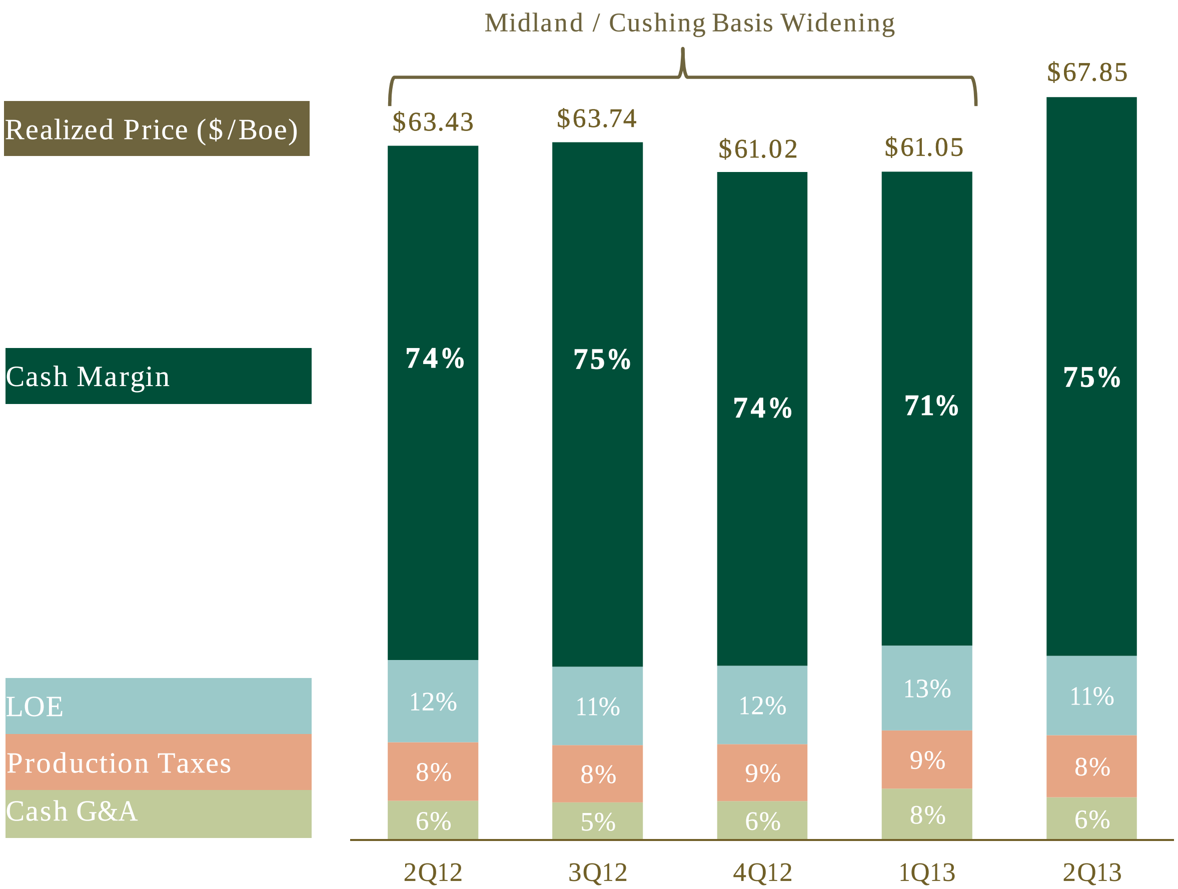
Operational Highlights

- Northern Delaware Basin well results set a new record
  - 35 new wells, including 3 extended length laterals and 1 dual lateral
- Southern Delaware Basin derisking on track; initial drilling locations identified
- Horizontal Wolfberry results encouraging; increasing YE13 wells to 16
- Reallocating 2H13 capital from vertical programs (Yeso, VT Wolfberry) to horizontal programs (Delaware Basin, HZ Wolfberry)

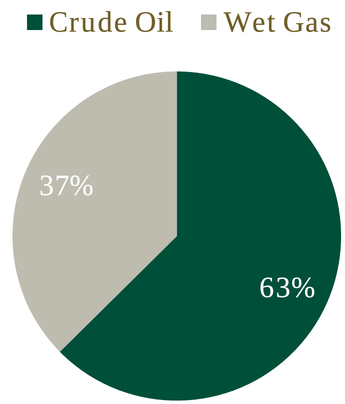
1 Daily oil production from continuing operations.

Low Cost, High Margin Operations

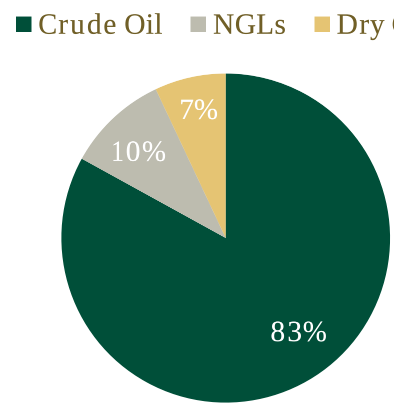
Unhedged Cash Margin[1]



2Q13 Product Mix

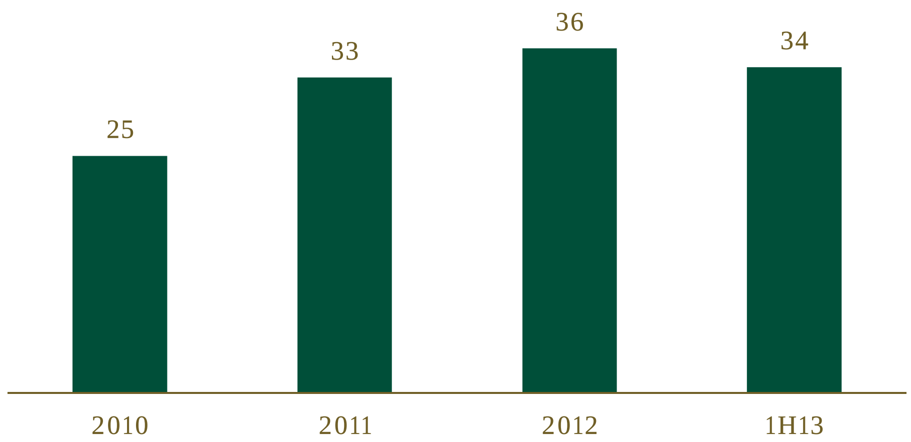


2Q13 Revenue Mix

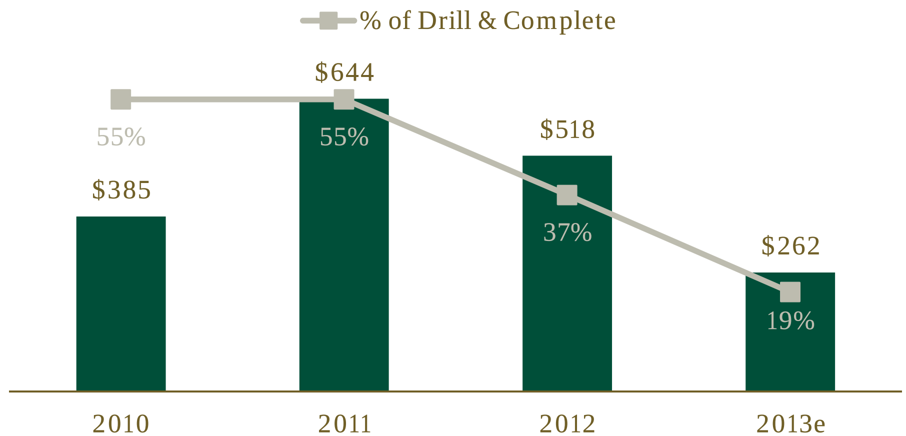


1 Unhedged Cash Margin represents oil & natural gas revenues, less lease operating expenses, oil & natural gas taxes and cash G&A expense (excludes stock-based compensation), divided by production. Percentages may not sum to 100% due to rounding.

New Mexico Shelf Production[1] (MBoepd)



New Mexico Shelf Drilling & Completion Capex ($mm)

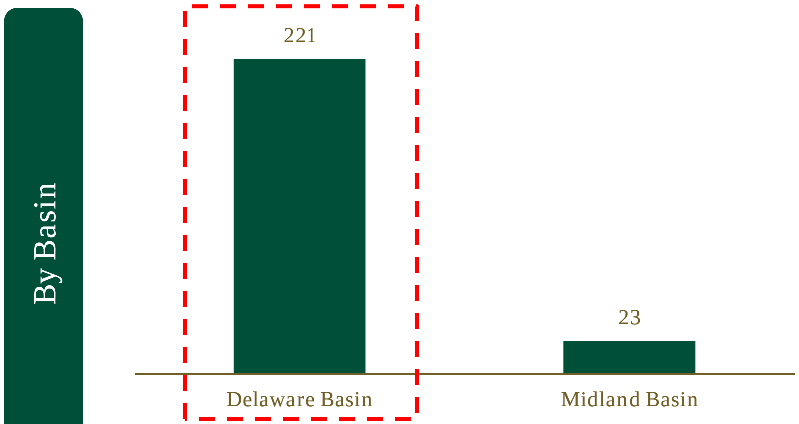


1 Daily production from continuing operations.
2 Based on $90/Bbl and $4/MMBtu.

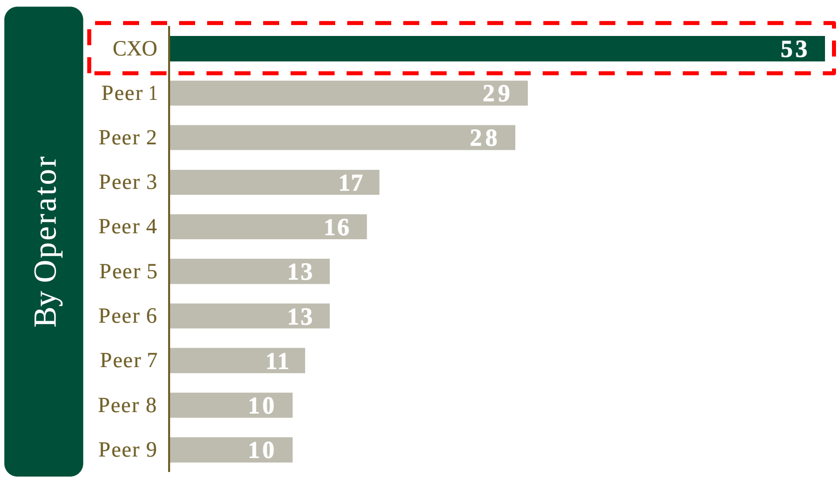
New Mexico Shelf Operations

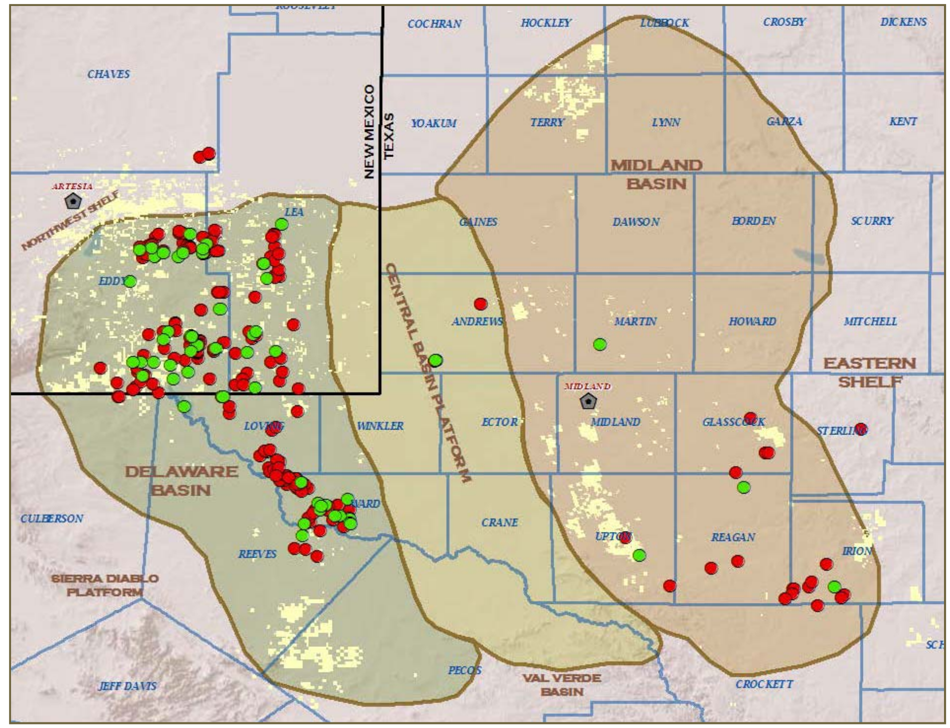
- New Mexico Shelf remains a world-class asset with high-ROR drilling opportunities
  - Horizontal: 676 locations, 44% ROR[2]
  - Vertical: 1,044 locations, 44% ROR[2]
- Production curtailments due to ongoing midstream constraints
  - New Frontier Field Services high-pressure gas line failed
  - Frontier Field Services gas plant expansion delayed
- Impact to annual production ~700 MBoe
  - YTD impact ~375 MBoe
- Midstream issues expected to be largely resolved by YE13
- Plan to eventually resume normal drilling operations
  - Currently operating 1 horizontal rig
- Reallocating 2H13 capital to horizontal operations in the Delaware and Midland Basins

Permian Basin Horizontal Wells with Peak Month Oil Rate > 500 Bpd (first production after 1/1/12)



Total	850	355





Concho Acreage

2012 Horizontal Wells with Peak Month Oil Rate > 500 Bpd

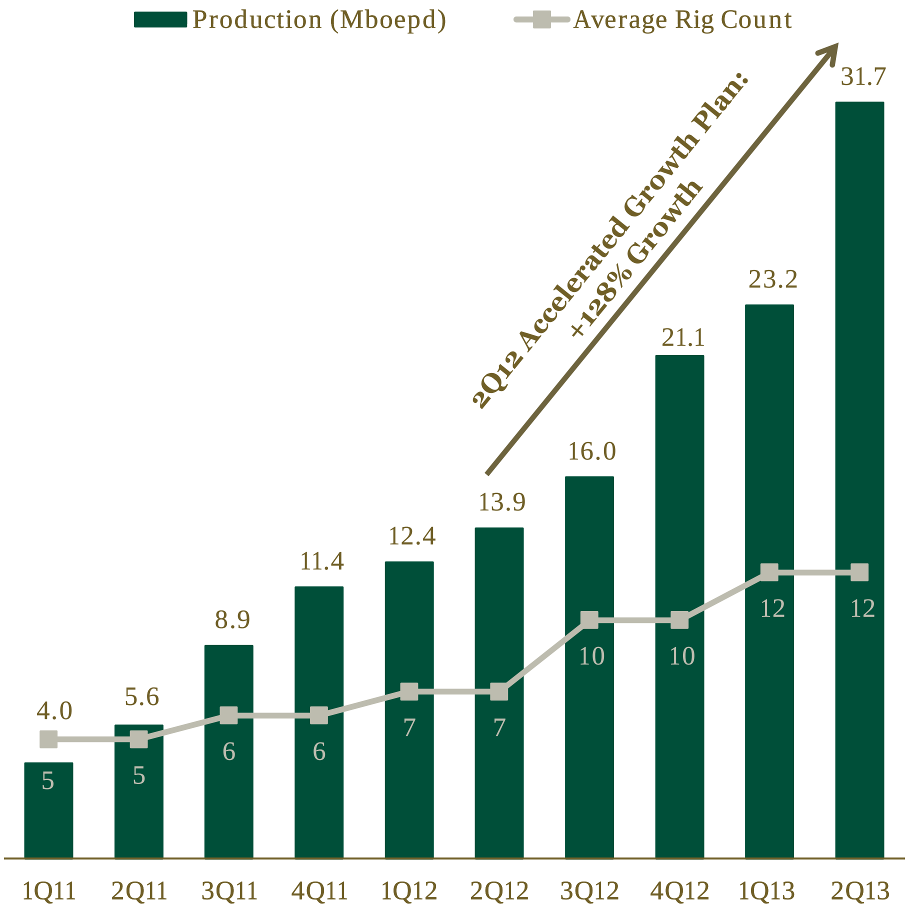
2013 Horizontal Wells with Peak Month Oil Rate > 500 Bpd

Greater industry de-risking and oil rates in the Delaware Basin

Source: DI Desktop. Production as of May 2013.
Peers include APC, BOPCO, DVN, EOG, EGN, Mewbourne, OXY, RDS and XEC.

Delaware Basin – Impressive Track Record

Horizontal Delaware Basin Production[1]



% Oil	39%	56%	51%	55%	50%	52%	49%	54%	58%	63%

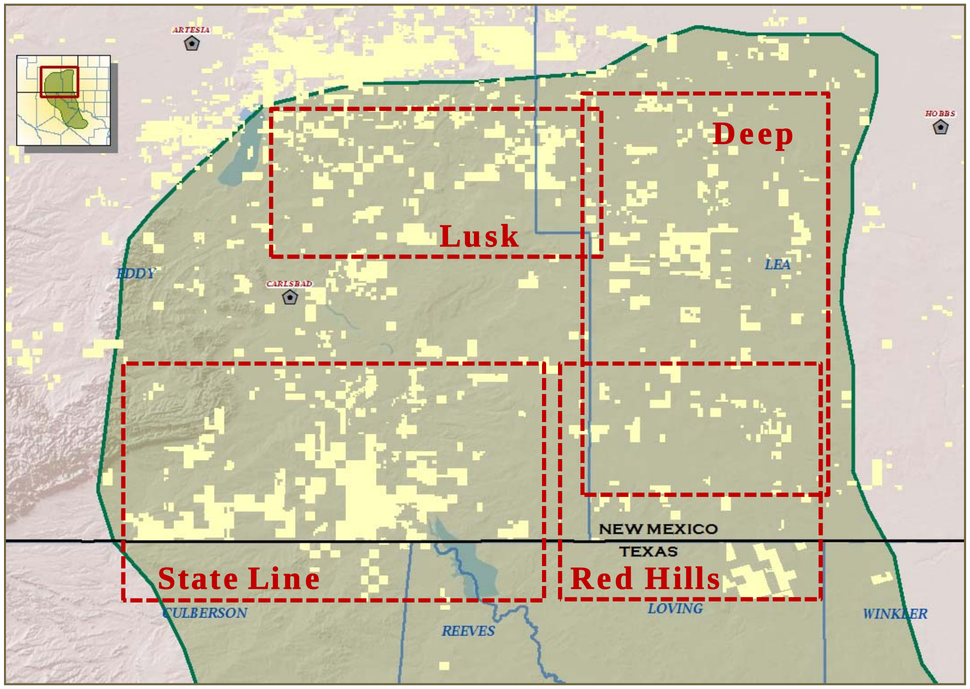
Delaware Basin Operations

- Horizontal Delaware Basin production grew 37% in 2Q13 over 1Q13 – *a new record*
  - Crude oil driving the growth
  - Robust results in both northern and southern Delaware Basin
- In less than 2.5 years, Delaware Basin now Concho's largest producing core area
- Rapid growth offsetting challenges in the New Mexico Shelf
- Increasing 2H13 Delaware Basin capital allocation in response to Shelf midstream constraints
- Currently running 14 horizontal rigs

1 Excludes legacy production from vertical wells that were acquired from Marbob and Three Rivers. During 2Q13 average production from these wells was 4.5 MBoepd.

Northern Delaware Basin Horizontal Well Performance

Northern Delaware Basin



Quarterly Well Performance

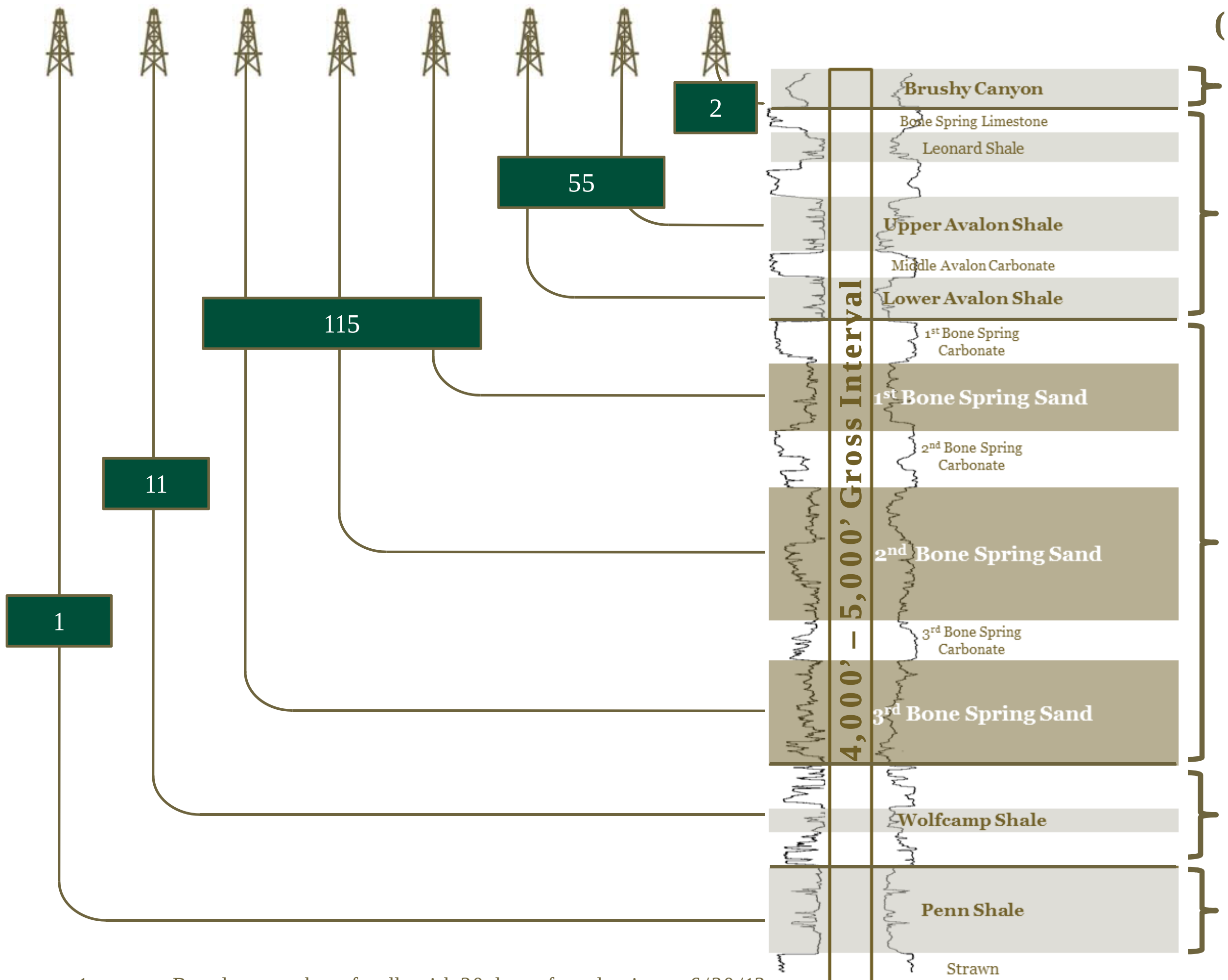
Results by Horizon

		Average IP Rate (Boepd)		
	# of Wells	30-Day	24-Hour Peak	% Oil[1]
Brushy Canyon	2	576	1,030	89%
Avalon	55	684	1,233	43%
Bone Spring	115	772	1,242	80%
Wolfcamp	11	756	1,113	39%

1 Based on average 30-Day IP Rate.

Northern Delaware Basin Development and Inventory

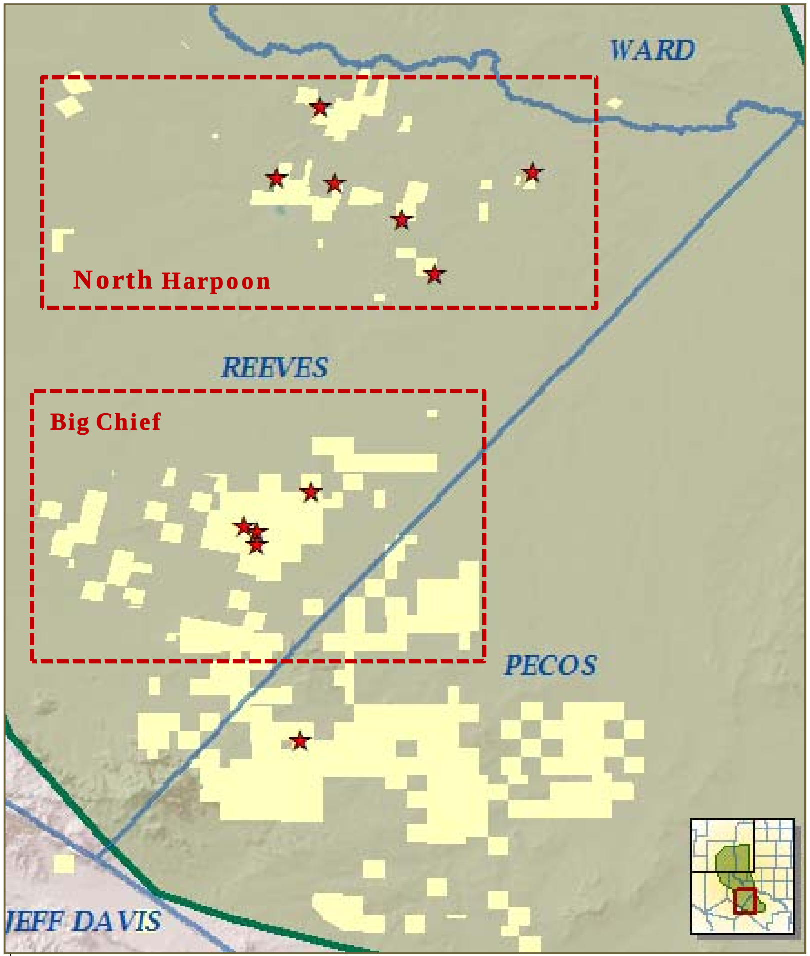
Mulit-Zone Well Count[1]	Target Zone	Average Rate (Boepd) (30-Day / 24-Hr Peak)	YE12 Inventory
	Brushy Canyon	576 / 1,030	Pending
	Bone Spring Limestone, Leonard Shale, Upper Avalon Shale, Middle Avalon Carbonate, Lower Avalon Shale	684 / 1,233	1,016
	1st Bone Spring Carbonate, 1st Bone Spring Sand, 2nd Bone Spring Carbonate, 2nd Bone Spring Sand, 3rd Bone Spring Carbonate, 3rd Bone Spring Sand	772 / 1,242	2,462
	Wolfcamp Shale	756 / 1,113	Pending
	Penn Shale		Pending



1 Based on number of wells with 30 days of production at 6/30/13.

Emerging Play – Southern Delaware Basin

Southern Delaware Basin



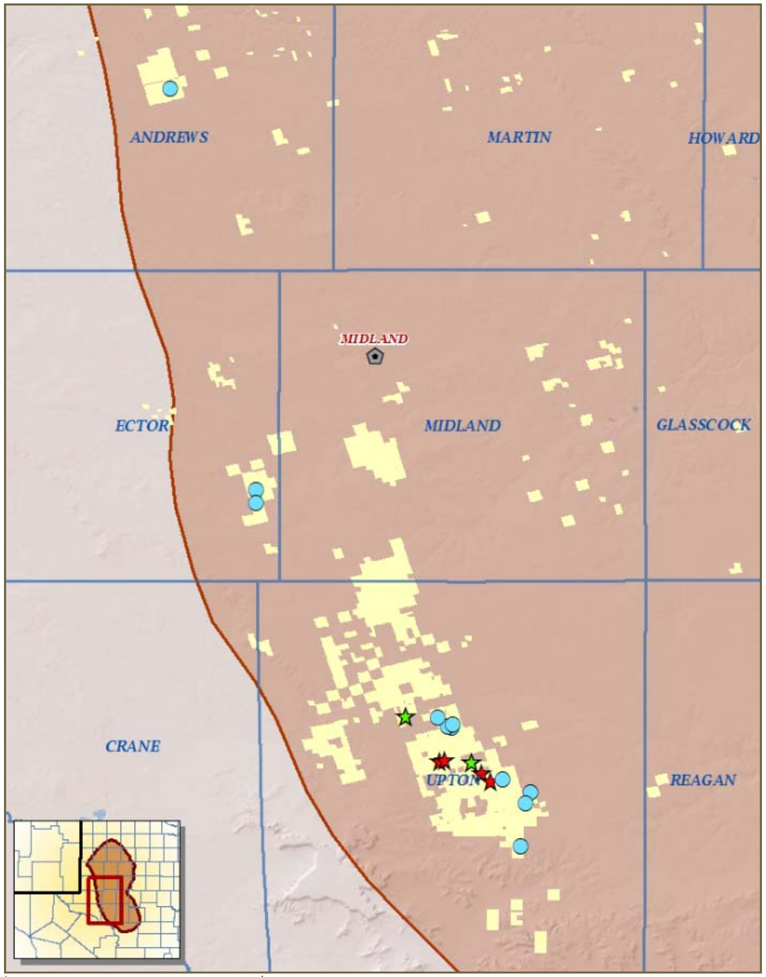
★ Producing Well

Southern Delaware Basin Activity

- Primary activity to date has been focused on Reeves County
  - North Harpoon and Big Chief prospects
- Successful drilling results and extensive geological and geophysical work have derisked ~20% southern Delaware Basin acreage
- ~200 Upper Wolfcamp drilling locations initially identified on derisked acreage
  - Over 50% of locations assume extended-length laterals
- Potential to add locations through:
  - Continued acreage derisking
  - Additional zones – Delaware sands, Avalon, Bone Spring, Middle Wolfcamp
- Initial well results (average of 11 wells):
  - 30-day IP rate: 691 Boepd (78% oil)
  - 24-hour peak rate: 1,082 Boepd
  - 4,182' lateral
- Well characteristics (4,500' - 8,000' lateral):
  - D&C: $8.5 - $10.5mm
  - EUR: 500 - 700 MBoe (75% oil)

Emerging Play – Horizontal Wolfberry (Midland Basin)

Horizontal Wolfberry – Midland Basin



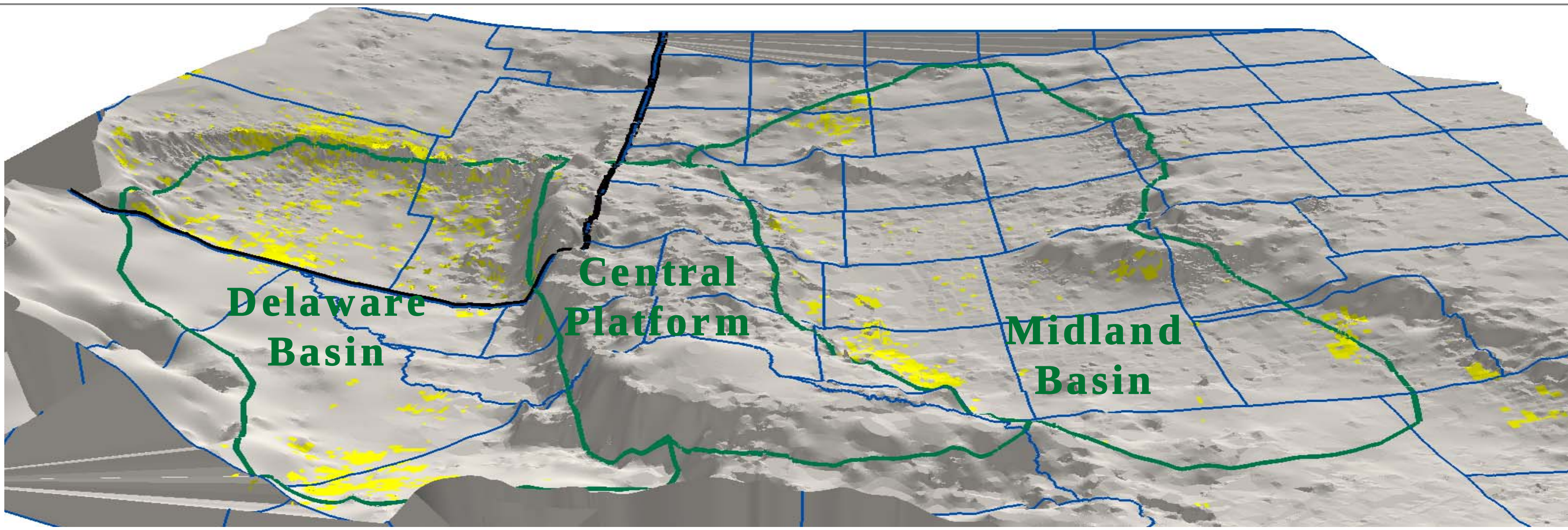
Producing Well | Completing Well | 2013 Planned Well

Horizontal Wolfberry Activity

- Increasing 2013 horizontal Wolfberry activity for 2nd time this year
  - Plan to drill 11 additional horizontal wells by YE13
  - Currently running 2 horizontal rigs
- 2013 drilling activity testing multiple horizontal concepts across core Wolfberry play:
  - 40-acre Wolfberry
  - 20-acre infill Wolfberry
  - Undeveloped Wolfberry
- Current focus on Wolfcamp A/B
  - Evaluating other zones in Wolfcamp and Spraberry for horizontal development
- Existing activity concentrated in Upton Co.
  - Plan to test Midland, Ector and Andrews Cos.
- Initial well results among the best in the industry (average of 4 wells):
  - 30-day IP rate: 742 Boepd (74% oil)
  - 24-hour peak rate: 1,010 Boepd
  - 3,975' lateral
- Currently no horizontal Wolfberry locations included in drilling inventory

- Established premier asset position in the Permian Basin
  - Delaware Basin
  - Midland Basin
  - New Mexico Shelf
- Identified significant resource potential across core assets capable of delivering long-term growth
- Building future resource upside through exploration activities in the southern Delaware Basin and horizontal Wolfberry (Midland Basin)
- Delivering best-in-class drilling results in the Delaware Basin and Midland Basin
- Expanding operational scale for greater execution optionality

Appendix

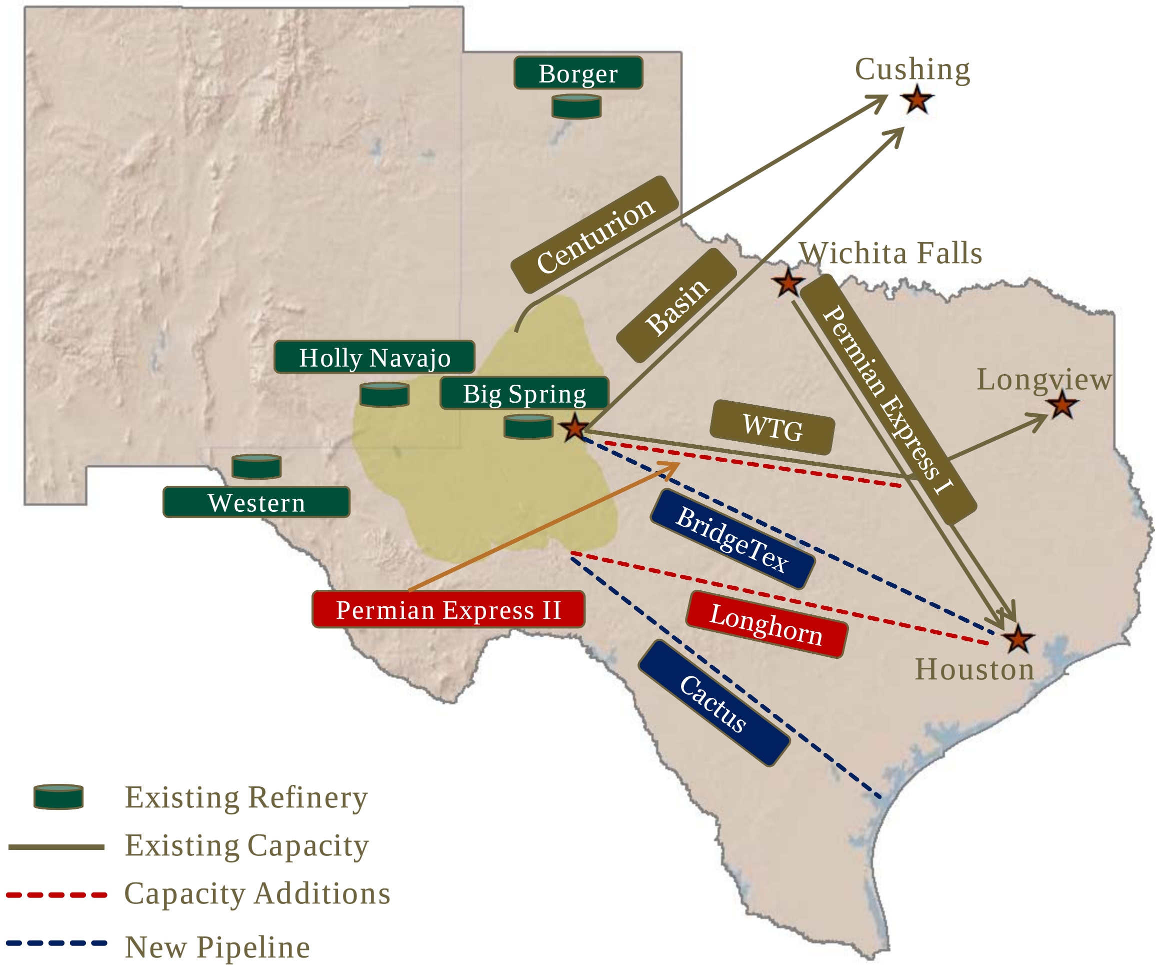


PERIOD	SERIES	DELAWARE BASIN FORMATION
GUADALUPE	DELAWARE GROUP	LAMAR BELL CANYON
		CHERRY CANYON
		BRUSHY CANYON
LEONARD	UPPER AVALON SHALE	
	LOWER AVALON SHALE	
	1ST BONE SPRING	
	2ND BONE SPRING	
	3RD BONE SPRING	
WOLFCAMP	WOLFCAMP	
PENN	PENNSYLVANIAN	

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

PERIOD	SERIES	MIDLAND BASIN FORMATION
GUADALUPE	WHITE-HORSE	TANSILL
		YATES
		7 RIVERS
		QUEEN
		GRAYBURG
	WARD	SAN ANDRES
		GLORIETA
LEONARD	CLEAR FORK	UPPER LEONARD
	UPPER SPRABERRY	
	LOWER SPRABERRY	
	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
WTG Pipeline (Sunoco)	225
Longhorn Pipeline Phase I (Magellan)	75
Permian Express I - Phase I (Sunoco)	90
Total	**940**

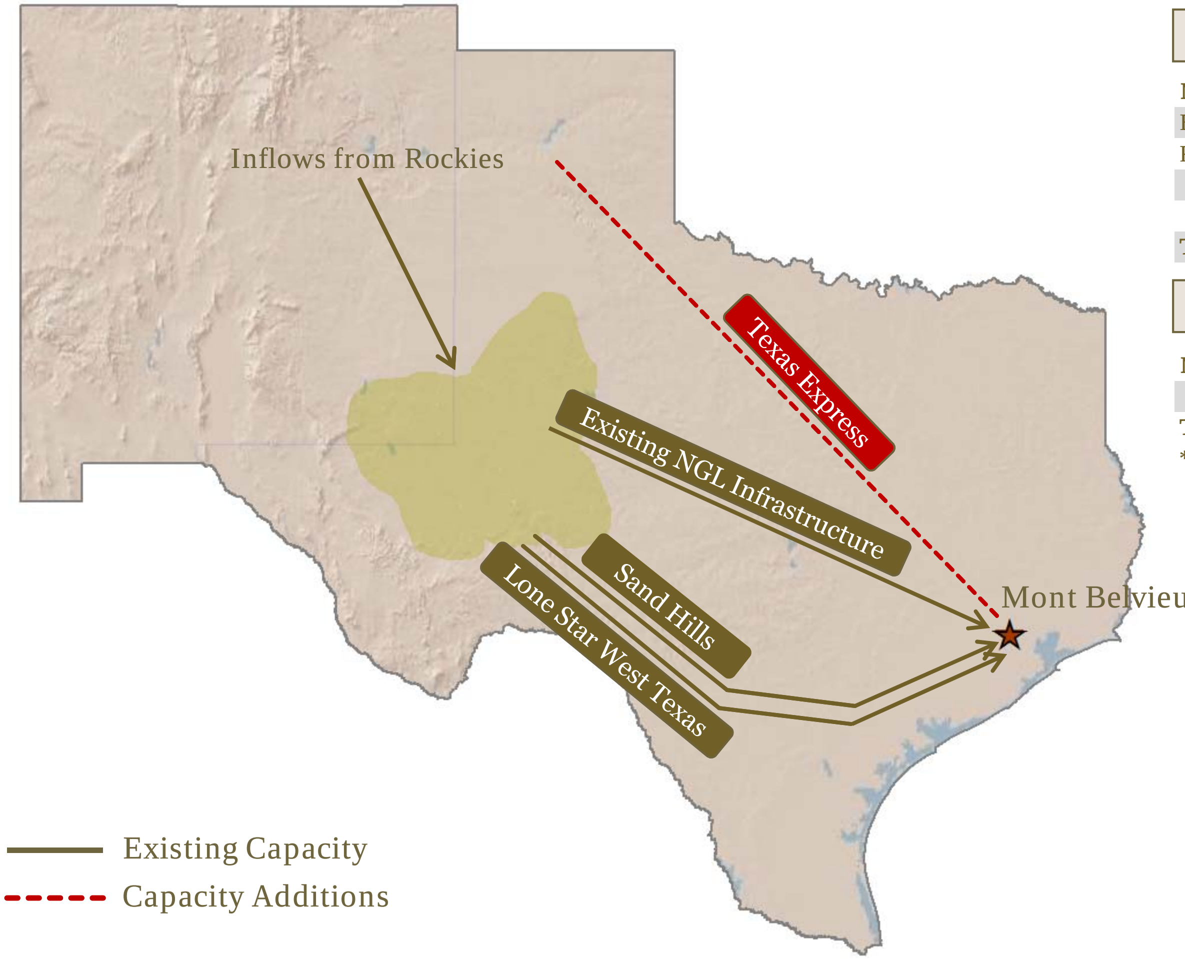
Rail[1]	MBopd
Total	**75**

Expansion Capacity

Oil Expansions	Completion Date	MBopd
Magellan		
Longhorn Reversal (Phase II)	3Q13	150
BridgeTex Crude Oil Pipeline	2Q14	300
Sunoco		
WTG Pipeline	3Q13	110
Permian Express I (Phase II)	1Q14	60
Permian Express II	3Q14	200
Plains All American		
Cactus Pipeline	1Q15	200
Total		**1,020**

1 Internal Estimate as of 3/31/13.

Permian Basin – NGL Takeaway Capacity



Existing Takeaway

NGL Pipelines	MBblpd
Existing NGL Infrastructure	707
Recent NGL Infrastructure Additions	
Lone Star West Texas	210
DCP Sand Hills	200
Total	**1,117**

Expansion Capacity

NGL Expansions	Completion Date	MBblpd
Texas Express NGL Pipeline*	3Q13	280
Total		**280**

*Originates in the Texas Panhandle

EBITDAX Reconciliation

Historical EBITDAX

(in thousands)	Three Months Ended March 31, 2013	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income	$ 30,093	$ 84,713	$ 319,297	$ 114,806	$ 350,414
Exploration and abandonments	18,407	8,398	14,398	26,805	20,377
Depreciation, depletion and amortization	168,420	188,730	133,267	357,150	260,530
Accretion of discount on asset retirement obligations	1,394	1,442	901	2,836	1,742
Impairments of long-lived assets	-	65,375	-	65,375	-
Non-cash stock-based compensation	6,767	8,588	7,347	15,355	13,475
Unrealized (gain) loss on derivatives not designated as hedges	65,033	(68,749)	(394,763)	(3,716)	(268,581)
(Gain) loss on sale of assets, net	5	(137)	(827)	(132)	68
Interest expense	52,106	54,079	41,899	106,185	77,736
Loss on extinguishment of debt	-	28,616	-	28,616	-
Income tax expense from continuing operations	10,977	53,338	191,707	64,315	205,322
Discontinued operations	(12,534)	453	14,185	(12,081)	28,440
EBITDAX	$ 340,668	$ 424,846	$ 327,411	$ 765,514	$ 689,523

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) unrealized (gain) loss on derivatives not designated as hedges, (7) (gain) loss on sale of assets, net (8) interest expense, (9) loss on extinguishment of debt, (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 (which includes continuing and discontiued operations) 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

Historical Adjusted Net Income

(in thousands, except per share amounts)	Three Months Ended March 31, 2013	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income - as reported	$ 30,093	$ 84,700	$ 319,297	$ 114,793	$ 350,414
Adjustments for certain non-cash and unusual items:					
Unrealized (gain) loss on commodity derivatives	65,033	(68,749)	(394,763)	(3,716)	(268,581)
Impairments of long-lived assets	-	65,375	-	65,375	-
Leasehold abandonments	4,387	2,940	8,437	7,327	8,557
Loss on extinguishment of debt	-	28,616	-	28,616	-
Discontinued operations:					
(Gain) loss on sale of assets	(20,363)	764	-	(19,599)	-
Tax impact	(18,887)	(11,144)	147,577	(30,031)	99,329
Adjusted net income	$ 60,263	$ 102,502	$ 80,548	$ 162,765	$ 189,719
Adjusted earnings per share:					
Basic	$ 0.58	$ 0.98	$ 0.78	$ 1.55	$ 1.84
Diluted	$ 0.58	$ 0.98	$ 0.78	$ 1.55	$ 1.83

CONCHO

Unhedged Cash Margin Reconciliation

Historical Unhedged Cash Margin

($ in thousands, except per unit data)	2012 2Q12	2012 3Q12	2012 4Q12	2013 1Q13	2013 2Q13
Net income	$ 319,297	$ 5,988	$ 75,287	$ 30,093	$ 84,700
Exploration and abandonments	14,398	6,958	12,505	18,407	8,398
Depreciation, depletion and amortization	133,267	148,145	166,453	168,420	188,730
Accretion of discount on asset retirement obligations	901	1,084	1,361	1,394	1,442
Impairments of long-lived assets	-	-	-	-	65,375
Non-cash stock-based compensation	7,347	7,959	8,438	6,767	8,558
(Gain) loss on derivatives not designated as hedges	(403,050)	135,415	(17,901)	59,017	(70,324)
Interest expense	41,899	51,337	53,632	52,106	54,079
Loss on extinguishment of debt	-	-	-	-	28,616
Other (income) expense, net	535	3,114	3,670	109	(107)
Income tax expense (benefit)	191,707	(995)	46,714	10,977	53,351
Discontinued operations (a)	14,185	14,962	21,299	(12,534)	453
Unhedged Cash Margin	$ 320,486	$ 373,967	$ 371,458	$ 334,756	$ 423,271
Production	6,823 MBoe	7,806 MBoe	8,220 MBoe	7,733 MBoe	8,295 MBoe
Unhedged Cash Margin ($/Boe)	$ 46.97	$ 47.91	$ 45.19	$ 43.29	$ 51.03
Average price without derivatives ($ /Boe)	$ 63.43	$ 63.74	$ 61.02	$ 61.05	$ 67.85
Unhedged Cash Margin (%)	74%	75%	74%	71%	75%

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

Hedges as of 10/1/13

Current Hedges as of 10/1/13

	2013 4Q	2013 Total	2014	2015	2016	2017
Oil Swaps: (a)						
Volume (Bbl)	4,614,000	4,614,000	15,040,000	11,717,000	429,000	168,000
Price per Bbl	$ 95.87	$ 95.87	$ 91.76	$ 86.72	$ 88.31	$ 87.00
Oil Basis Swaps: (b)						
Volume (Bbl)	3,404,000	3,404,000	9,475,000	-	-	-
Price per Bbl	$ (1.12)	$ (1.12)	$ (0.46)	-	-	-
Natural Gas Swaps: (c)						
Volume (MMBtu)	6,992,000	6,992,000	-	-	-	-
Price per MMBtu	$ 4.25	$ 4.25	-	-	-	-
Natural Gas Collars: (d)						
Volume (MMBtu)	-	-	21,900,000	-	-	-
Price per MMBtu	-	-	$3.85 - $4.40	-	-	-
Natural Gas Basis Swaps: (e)						
Volume (MMBtu)	6,440,000	6,440,000	-	-	-	-
Price per MMBtu	$ (0.15)	$ (0.15)	-	-	-	-

(a) The index prices for the oil swaps are based on the NYMEX — West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland — WTI and Cushing — WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX — Henry Hub last trading day futures price.
(d) The index prices for the natural gas collars are based on the El Paso Permian delivery point.
(e) The basis differential price is between the El Paso Permian delivery point and NYMEX — Henry Hub delivery point.

Updated 2013 Guidance

Concho 2013 Production and Operating Guidance

Production:	
Oil equivalent (MMBoe)	33.4 - 34.8
% Oil	60% - 62%
Price differentials to NYMEX:	
(excluding the effects of hedging)	
Oil (Bbl)	93% - 95%
Natural gas (Mcf)	120% - 140%
Operating costs and expenses:	
Lease operating expense:	
Direct lease operating expense ($/Boe)	$7.50 - $8.00
Oil & natural gas taxes (% of oil and natural gas revenue)	8.25%
G&A expense:	
Cash G&A expense ($/Boe)	$3.25 - $3.75
Non-cash stock based compensation ($/Boe)	$1.10 - $1.20
DD&A expense ($/Boe)	$22.00 - $24.00
Exploration, abandonments and G&G ($/Boe)	$1.50 - $2.50
Cash interest rates:	
$600 million senior notes due 2021	7.00%
$600 million senior notes due 2022	6.50%
$600 million senior notes due 2022	5.50%
$1.55 billion senior notes due 2023	5.50%
Remainder of debt	LIBOR + (150 - 250 bps)
Non-cash interest expense ($ in millions)	$11.0 - $13.0
Income taxes:	38%
Percent deferred of total taxes	75% - 85%
Capital expenditures ($ in billions)	$1.6