Investor Presentation

September 2016

Forward Looking Statements

This presentation contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

- future financial and operating performance and results;
- business strategy;
- market prices;
- future use of derivative financial instruments; and
- plans and forecasts.

The Company based these forward-looking statements on current assumptions, expectations and projections about future events.

The Company uses the words “may,” “expect,” “anticipate,” “estimate,” “believe,” “continue,” “intend,” “plan,” “potential,” "project," “budget” and other similar words to identify forward-looking statements. The statements that contain these words should be read carefully because they discuss future expectations, contain projections of results of operations or financial condition and/or state other “forward-looking” information. The Company does not undertake any obligation to update or revise any forward-looking statements, except as required by applicable securities laws. These statements also involve risks and uncertainties that could cause actual results or financial condition to materially differ from expectations in this presentation, including, but not limited to:

- fluctuations in the prices of oil and natural gas;
- the availability of oil and natural gas;
- future capital requirements and availability of financing, including reductions to our borrowing base and limitations on our ability to incur certain types of indebtedness under our debt agreements;
- our ability to meet our current and future debt service obligations, including our ability to maintain compliance with our debt covenants;
- disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions, including estimates related to acquisitions and dispositions of oil and natural gas properties;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including those related to our activities in shale formations;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of water and other materials for drilling and completion activities;
- marketing of oil and natural gas;
- political and economic conditions and events in oil-producing and natural gas-producing countries;
- title to our properties;
- litigation;
- competition;
- our ability to attract and retain key personnel;
- general economic conditions, including costs associated with drilling and operations of our properties;
- our ability to comply with the listing requirements of, and maintain the listing of our common shares on, the New York Stock Exchange ("NYSE");
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases, legislation of derivative financial instruments, regulation of hydraulic fracture stimulation and elimination of income tax incentives available to our industry;
- receipt and collectability of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- potential acts of terrorism;
- our ability to manage joint ventures with third parties, including the resolution of any material disagreements and our partners’ ability to satisfy obligations under these arrangements;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates;
- our ability to effectively integrate companies and properties that we acquire; and
- our ability to execute the business strategies and other corporate actions, including restructuring our balance sheet and gathering and transportation contracts

It is important to communicate expectations of future performance to investors. However, events may occur in the future that EXCO is unable to accurately predict, or over which EXCO has no control. Users of the financial statements are cautioned not to place undue reliance on a forward-looking statement. Any number of factors could cause actual results to differ materially from those in EXCO's forward-looking statements, including, but not limited to, the volatility of oil and natural gas prices, future capital requirements and the availability of capital and financing, uncertainties about reserve estimates, the outcome of future drilling activity, environmental risks and regulatory changes. Declines in oil or natural gas prices may have a material adverse effect on EXCO's financial condition, liquidity, results of operations, ability to fund operations and the amount of oil or natural gas that can be produced economically. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. EXCO undertakes no obligation to publicly update or revise any forward-looking statements. When considering EXCO's forward-looking statements, investors are urged to read the cautionary statements and the risk factors included in EXCO's Annual Report on Form 10-K for the year ended December 31, 2015, filed with the Securities and Exchange Commission ("SEC") on March 2, 2016 and its other periodic filings with the SEC.

Revenues, operating results and financial condition substantially depend on prevailing prices for oil and natural gas and the availability of capital. Declines in oil or natural gas prices may have a material adverse effect on financial condition, liquidity, results of operations, the amount of oil or natural gas that we can produce economically and the ability to fund operations. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

Agenda

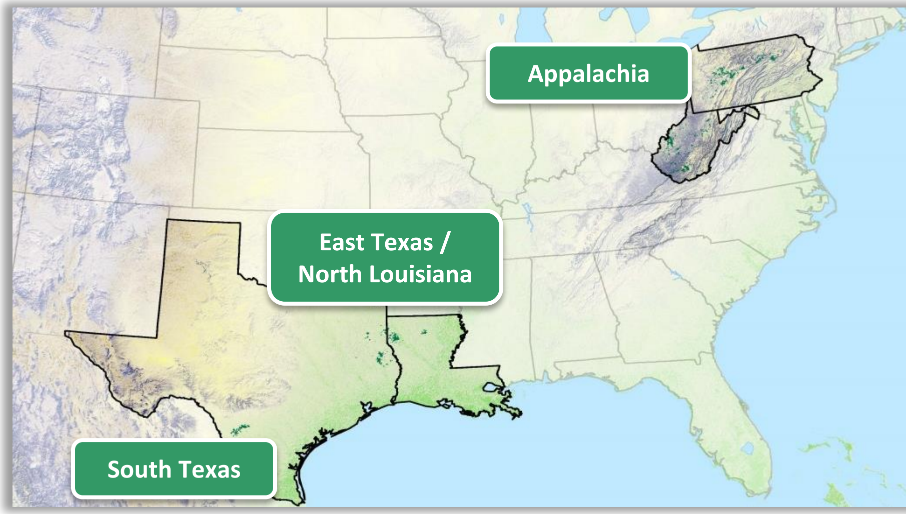
- Executive Summary
- Haynesville Transformation
- EXCO Overview
- Appendix

EXCO Overview: Three Concentrated Shale Resource Positions

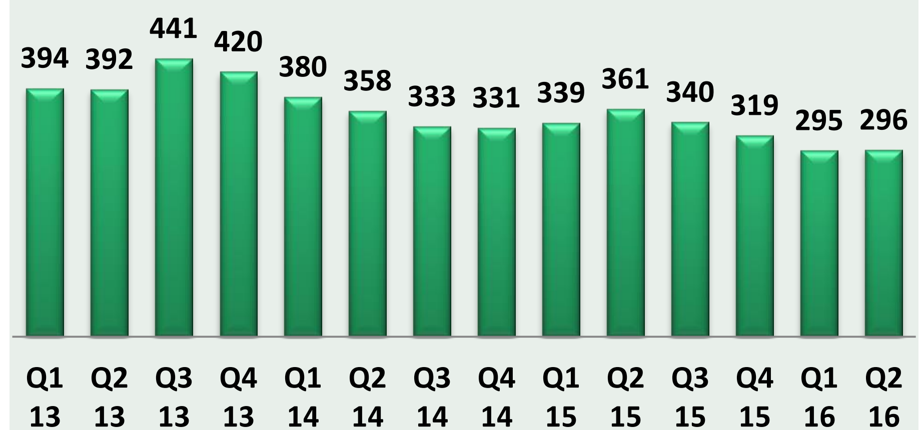
Overview 1

Attribute	Key Features
Net Acres[1]	• 353,350 net acres • 89% HBP
Net Production	• Q2 '16: 296 Mmcfe/d
Proved Reserves[2]	• 1.5 Tcfe • $1.2B PV-10
Key Credit Highlights	• EXCO Resources (NYSE: XCO) is a Dallas based E&P company with a focus on shale resource plays in Louisiana, Texas and the Appalachia region • Proven track record of high performance drilling and completion • 222 employees • Well situated, highly economic positions across multiple basins • Deep, multi-year inventory with 643 gross (240 net) drilling locations that achieve greater than 20% IRR at current prices[2] • Highly successful at reducing D&C and operating costs and eliminating overhead • Strong management team and sponsors • Substantial 1st lien asset coverage

Core Basins 2



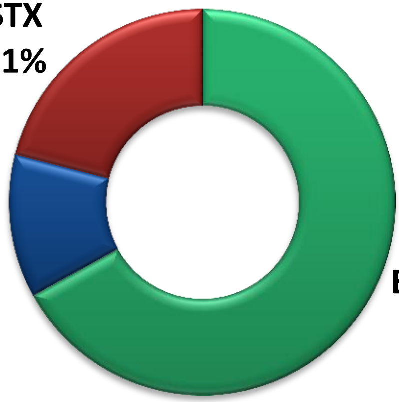
Net Production[3] 13-16; Mmcfe/d 3



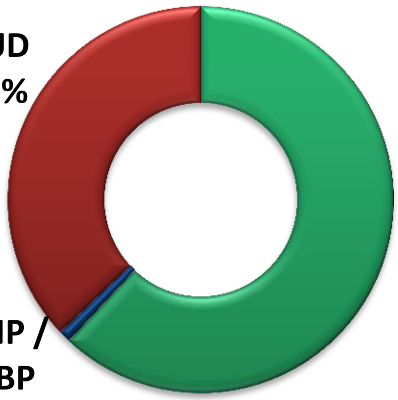
1. Acreage as of July 31,2016.
2. Based on ten year June 30, 2016 strip prices and pro forma for recent divestiture of assets in Pennsylvania and STX settlement
3. Net production excludes production from divested assets.

$1B+ Of Gas Focused Pro Forma Proved Reserves As Of June 30, 2016 With High Percentage Of PDP

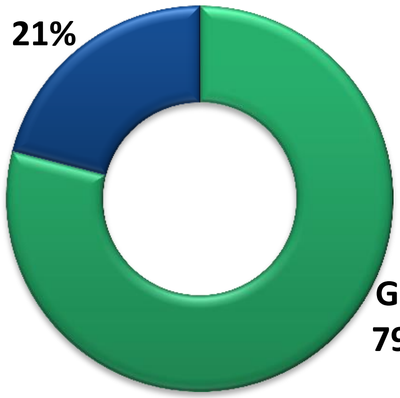
1P PV-10 By Area; % 1



1P PV-10 By Category; % 2



1P PV-10 By Commodity; % 3



1P NYMEX Reserves Breakdown[1] Jun 30, 2016; Mixed Measures 4

	Net Wells	Oil	Gas	Gas Equivalent	Gas Equivalent	Pre Tax PV-10
	#	Mbbls	MMcf	MMcfe	%	$MM
PDP	963	11,650	518,564	588,462	38	735
PNP/PBP	3	2	11,470	11,483	1	8
PUD	147	9,423	866,910	923,446	61	442
Proved Reserves	1,113	21,075	1,396,944	1,523,391	100	1,185
Marketing & Transport[2]						(223)
Proved Reserves Less Marketing & Transport	1,113	21,075	1,396,944	1,523,391	100	962

EXCO's Pre Tax Strip PV-10 has increased by 46% since year end 2015

Note: Reserves are pro forma for recent divestitures and assumes capital budget exists to fund development of PUDs.
1. Based on ten year June 30, 2016 strip prices.
2. Represents management's estimate of the total marketing and transportation liability net to EXCO. Effective January 1, 2017.

EXCO Pro Forma Capitalization

Sources and Uses 1

Sources: Tender Offer and Consent Solicitation ($ in millions)	
Cash from the Balance Sheet	$43
Total Sources	$43

Uses: Tender Offer and Consent Solicitation	
Repay Senior Unsecured Notes due 2022 ($101mm par retired)	$43
Total Uses	$43

Pro Forma Capitalization 2

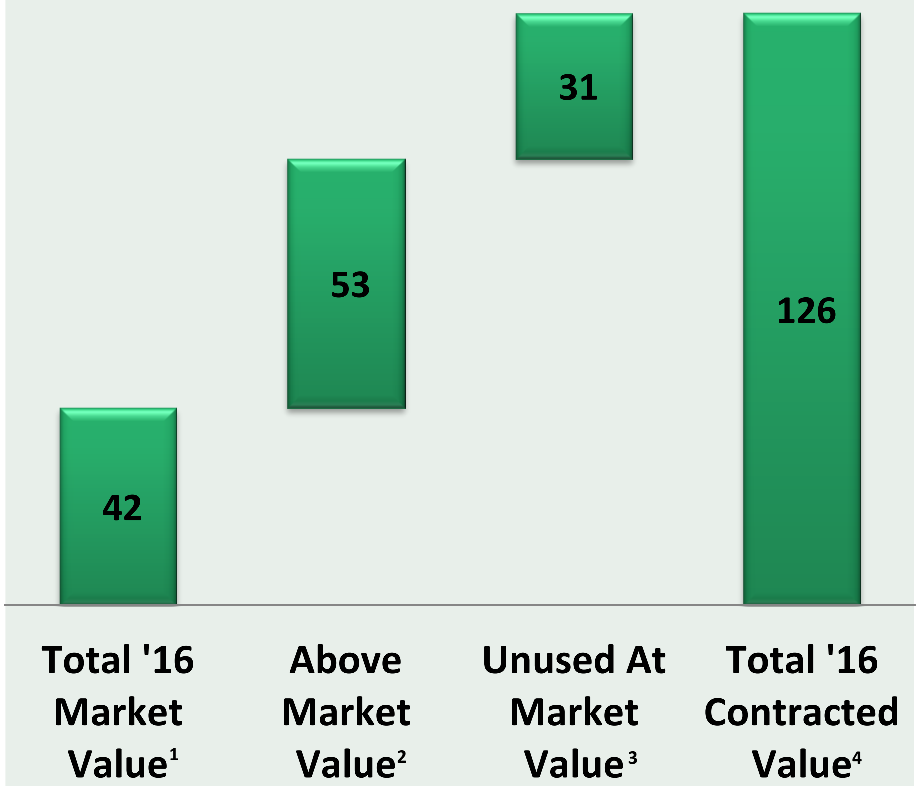
	As of	Tender Offer and Consent Solicitation	
($ in millions)	7/31/2016	Adjustment	Pro forma
Cash[1]	$82	($43)	$38
Credit Agreement	174		174
2nd Lien Term Loan	700		700
Total Secured Debt	$874	–	$874
7.500% Senior Notes due 2018	132		132
8.500% Senior Notes due 2022	171	(101)	70
Total Debt	$1,177	($101)	$1,075
Net Debt	$1,095	($58)	$1,037
Market Capitalization[2]	390		390
Enterprise Value	$1,485	($58)	$1,427
Liquidity[3]	223	(43)	180
Borrowing Base	325		325

1. Includes $25.4mm of restricted cash. See appendix for further detail on restricted cash components.
2. FactSet as of 7/31/16.
3. Liquidity reflects $10.2mm in Letters of Credit.

Restructure Gathering And Transportation Contracts To Enhance Liquidity

ETX/NLA Gross Transportation Commitments 16; $MM

1



Execution Strategy

2

- The Company is engaging its midstream and transportation providers to restructure these commitments
- More must be done to restructure contracts; opportunities include:
  - Market unutilized portion of transportation to increase utilization
  - Evaluate M&A transactions to increase utilization
  - Continue to blend and extend gathering and transportation contracts
  - Evaluate options to issue secured debt in exchange for cost relief
  - Consider other commercial options

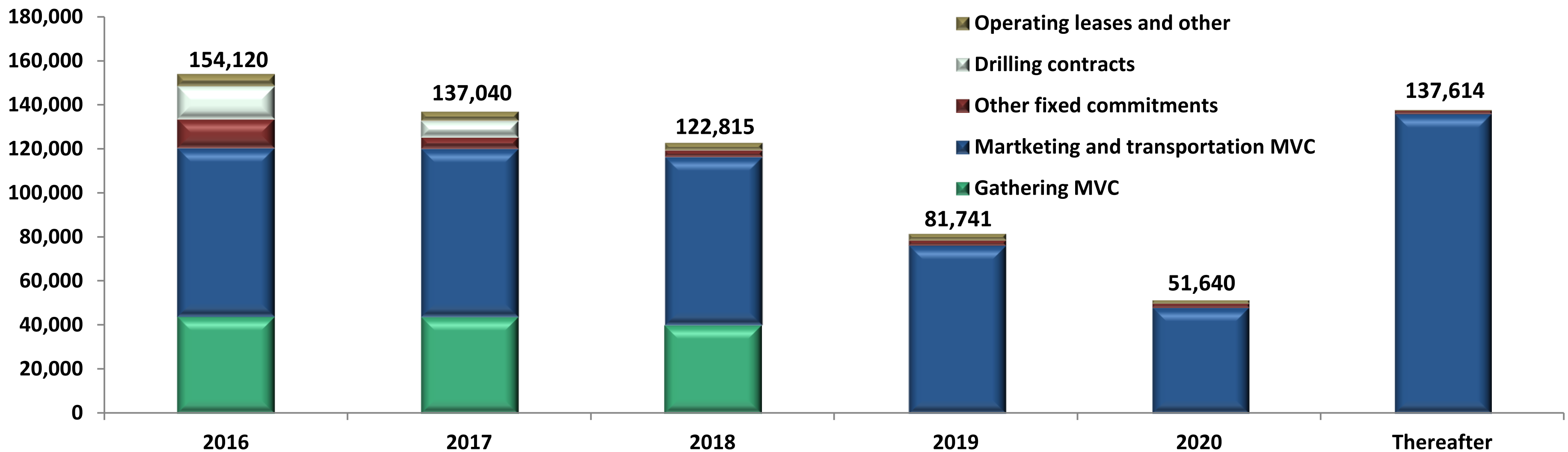
Out-of-market gathering and transportation contracts are an overwhelming burden to EXCO and negatively impact the Company's structural liquidity

1. Assumes estimated market value of $0.10/MMBtu for transportation and elimination of unused commitments.
2. Represents the difference between the contracted rates and the estimated market value of $0.10/MMBtu.
3. Represents estimated unused commitments at estimated market value of $0.10/MMBtu.
4. Gross amount due before any legally permitted sharing of costs with third parties.

Contractual Obligations And Commercial Commitments

Contractual Obligations and Commercial Commitments 16 – 20 and Thereafter; $M

1



Contractual Obligations and Commercial Commitments 16 – 20 and Thereafter; $M

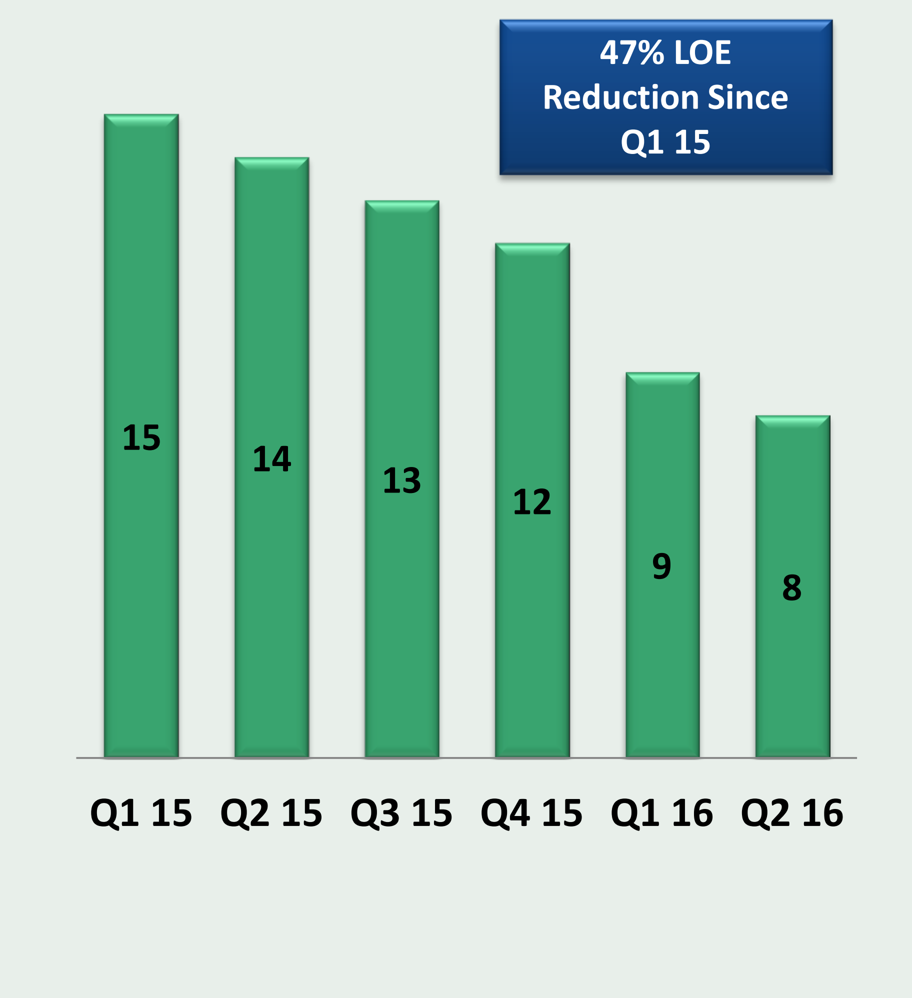
2

	Gathering minimum volume commitments	Marketing and transportation minimum volume commitments	Other fixed commitments	Drilling contracts	Operating leases and other	Total
2016	43,920	76,494	13,253	14,997	5,456	154,120
2017	43,800	76,285	5,443	7,284	4,228	137,040
2018	40,080	76,285	3,210	-	3,240	122,815
2019	-	76,285	2,403	-	3,053	81,741
2020	-	48,148	1,932	-	1,560	51,640
Thereafter	-	135,943	1,599	-	72	137,614
Total	127,800	489,440	27,840	22,281	17,609	684,970

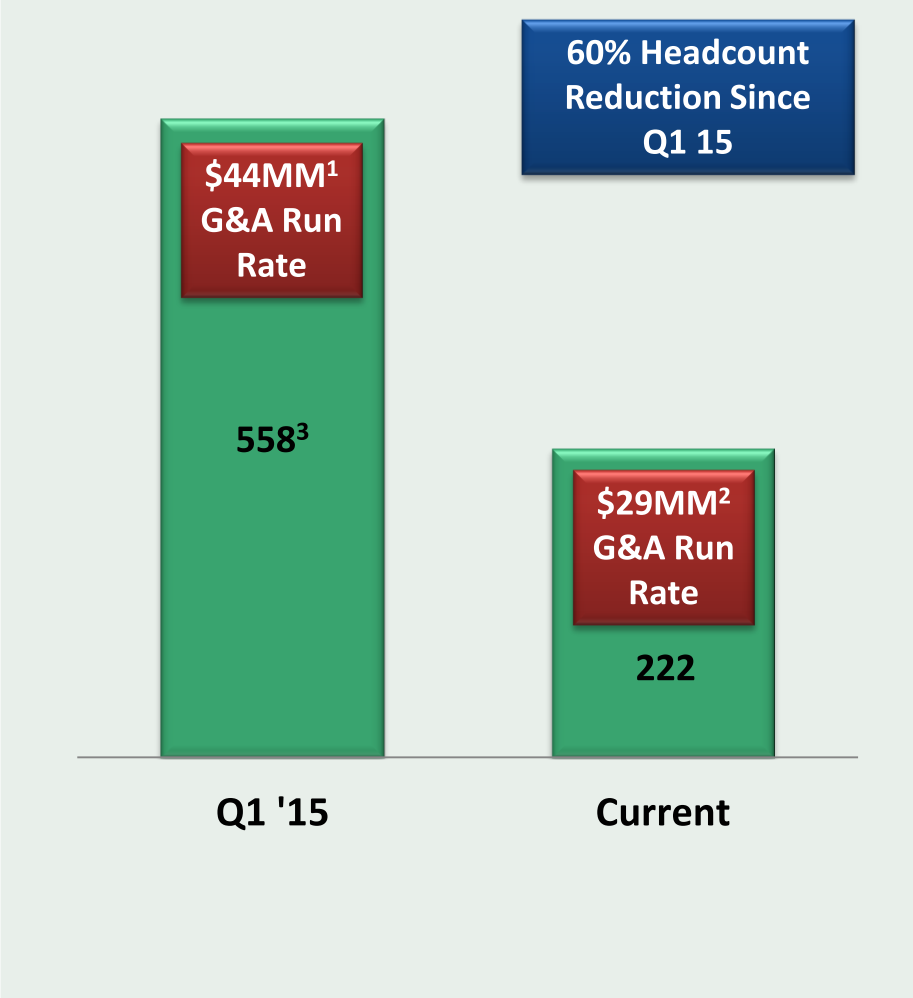
Note: Data represents contractual obligations and commercial commitments as of December 31, 2015 and does not include those related to equity method investments.

Reduce LOE And G&A Load To Reduce Fixed Cost Burden

LOE By Quarter
15-16; $MM **1**



Headcount Reduction
15-16; Mixed Measures **2**



The company continues to rationalize its costs as part of its restructuring efforts

1. Represents Q1 '15 GAAP G&A of $15.2MM adjusted to exclude $1.7mm of equity based compensation and $2.6mm of severance, annualized.
2. Represents Q2 '16 GAAP G&A of $17.0MM adjusted to exclude $9.3mm of equity based compensation and $0.5mm of severance, annualized.
3. Headcount as of January 1, 2015.

Agenda

Executive Summary

Haynesville Transformation

EXCO Overview

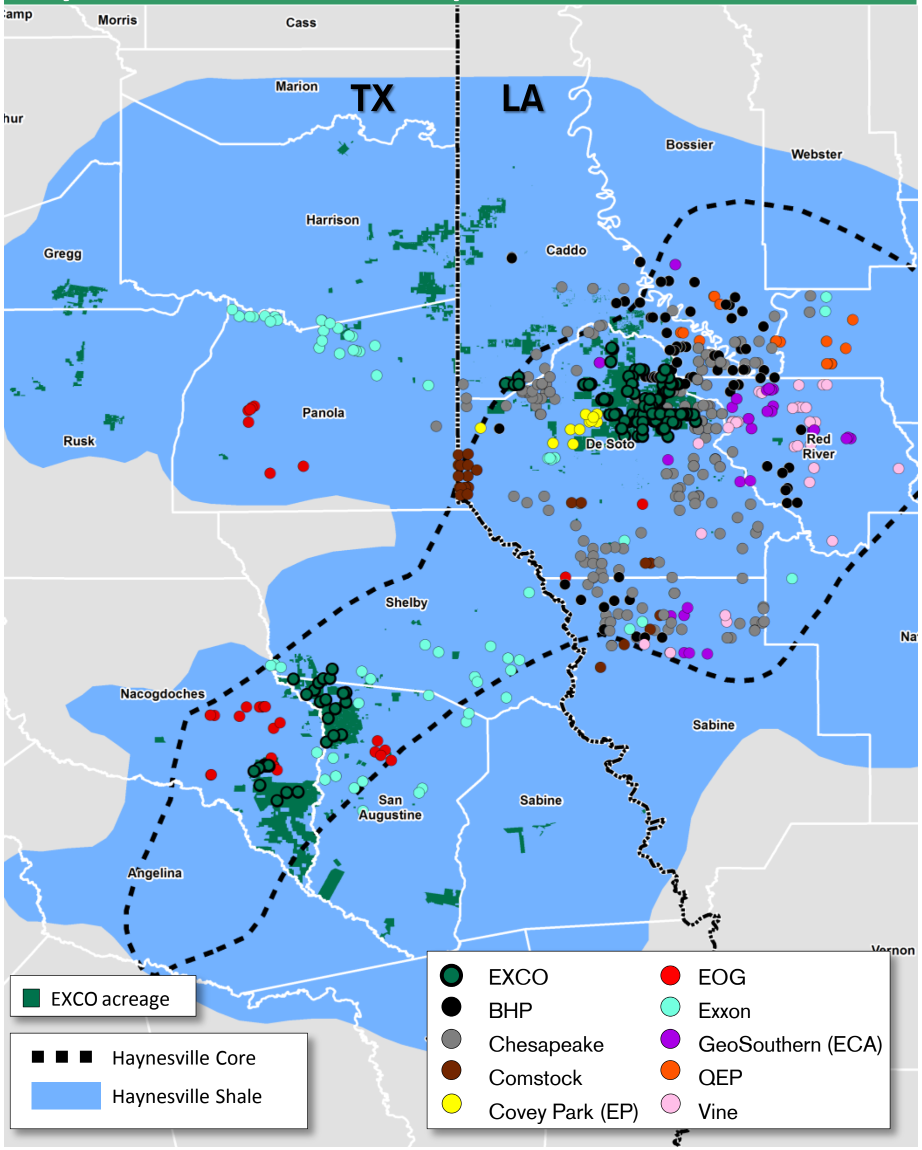
Appendix

EXCO Haynesville Relative Positioning

EXCO Haynesville Relative Positioning 1

- Established, world class gas play with significant well and seismic control allows for comprehensive understanding of reservoir dynamics and geological characteristics
- Proven large volume frac completion techniques generate EURs that more than double early well performance play results with substantially reduced costs have effectively re-rated the shale gas play's economics
- De-risked resource, highly delineated trend areas offer substantial proved reserves and repeatable opportunity set under favorable economic risk-reward scenarios
- Strong breakeven (IRR 25%) prices under $2.70 / Mmbtu that can compete with Appalachian shale gas plays in a differentiated U.S. region
- Located in an industry friendly regulatory environment allowing for better program development execution
- Existing midstream infrastructure in place with premium geographical access to LNG terminals and developing demand centers
- Drilling and completion costs have steadily decreased over the years with continuously demonstrated improvement
- Well positioned for a long-term rebound on gas prices and / or gas exports from the Gulf Coast

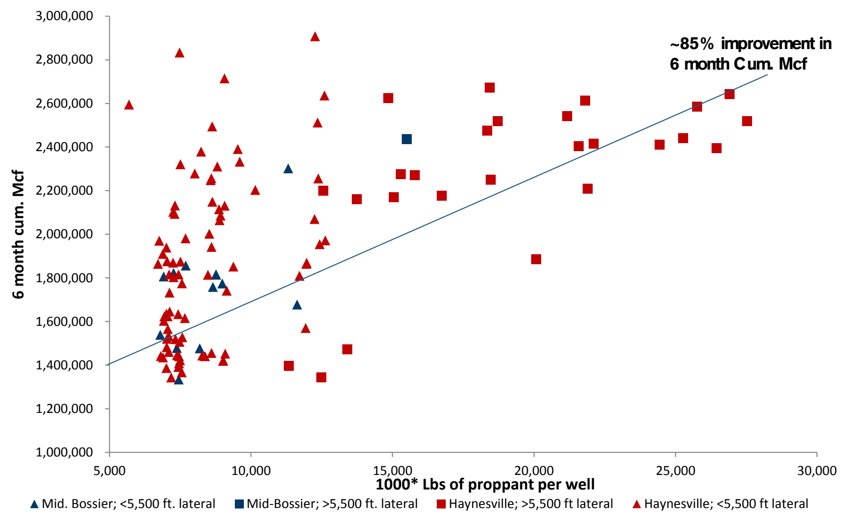
Haynesville Shale Area Map 2



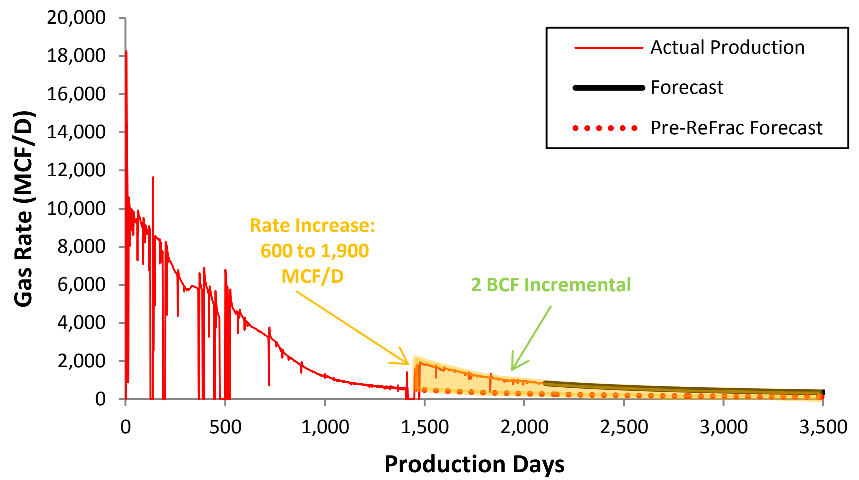
Source: IHS Performance Evaluator, investor presentations and company information. Horizontal wells with a first production date between 1/1/12 – 4/1/16 targeting Haynesville and Bossier horizons shown on map.

On-going New Completion Designs And Refrac Opportunities Are Re-Rating Play

Proppant to Mcf Breakdown 1



Haynesville Re-Frac Analysis 2



Key Takeaways 3

- The play has been economically re-rated through the application of modern completion designs using lessons learned from other resource plays and also benefitting from extensive technical and reservoir information
- Drilling and completion designs have evolved into larger wells and larger frac jobs with increasing EURs
- Larger fracs, longer laterals and wider spacing has increased the certainty of results and enhanced the inventory of economic opportunities
- Systematic new completion trials have been tested on the play by EXCO and several other operators in the core area have validated their results

Key Takeaways 4

- Operators in the play have engaged in a re-frac campaign to optimize completions from existing wells several years old with new technology and understanding developed over the last five years of intense shale development in the U.S.
- Diagnostic results have indicated that an average of 1/3 of the lateral is effectively stimulated by modern re-fracs
- Allows for a significant production uplift opportunity in the future
- EXCO has inventory of ~270 re-fracs
- Restimulation of producing wells through offset new well completions supports the re-frac concept, as producing wells have realized 3x or more production enhancement

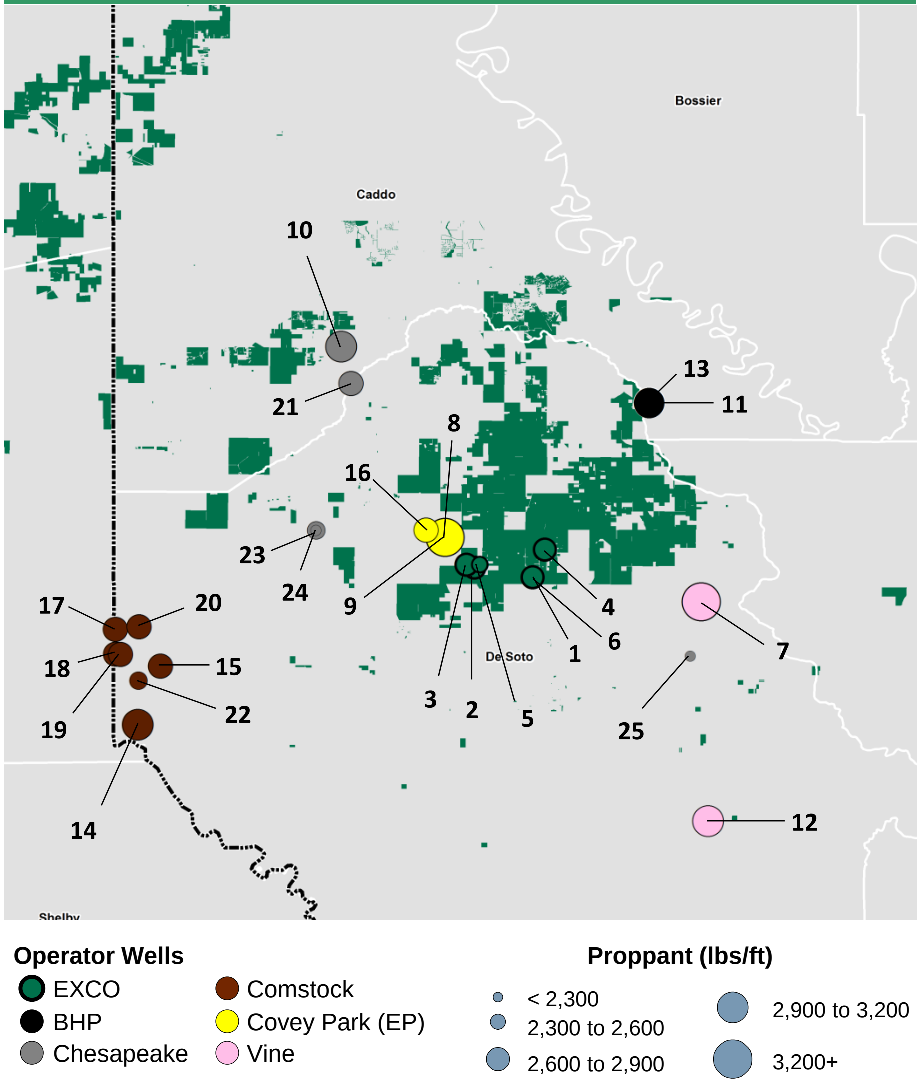
Source: RRC. Note that horizontal wells with a first production date between 1/1/13 – 4/1/16 targeting Haynesville and Bossier horizons with a lateral length of 3,000' or greater.

North Louisiana Holly Offset Well Results

	Well Name	Operator	Lat. Length	3 Months Cum Prod	6 Months Cum Prod	Proppant
			Ft	Mmcf / '000ft	Mmcf / '000ft	lbs/ft
	EXCO Holly Type Curve (EUR 2.1 Bcf/'000ft)	EXCO	4,500	290	521	2,700
1	Whitaker 9-4 HC 2	EXCO	7,596	N/A	N/A	2,763
2	Old Farms 1-1 ALT	EXCO	4,182	N/A	N/A	2,758
3	Gray 1-2 ALT	EXCO	4,253	N/A	N/A	2,755
4	Akin 4-9 HC 1	EXCO	7,666	N/A	N/A	2,632
5	BRP 1-1 ALT	EXCO	4,299	N/A	N/A	2,560
6	Whitaker 9-4 HC 1	EXCO	7,597	N/A	N/A	2,553
7	Robertson Clay 14 2 ALT	Vine	4,625	248	498	3,787
8	R P Oden Sr. 35-02 HC 1 ALT	EP	7,633	168	318	3,495
9	R P Oden Sr. 35-26 HC 1 ALT	EP	7,623	182	406	3,319
10	CA 12&13-15-15 HC 1H	CHK	9,814	N/A	N/A	3,000
11	EMW 29-32 HC 1 ALT	BHP	5,299	165	336	2,988
12	Rocking G Farms 23 3 ALT	Vine	4,781	206	334	2,966
13	EMW 29-32 HC 2 ALT	BHP	5,421	117	193	2,948
14	Caraway Estate 20-29 HC 1 ALT	CRK	5,953	194	347	2,912
15	Gamble 4-33 HC 1 ALT	CRK	7,547	130	205	2,879
16	Lowrey 27 2 ALT	EP	4,536	170	319	2,788
17	Harrison 30-19 1 ALT	CRK	7,437	114	194	2,731
18	Pyle 6-7 1 ALT	CRK	7,578	123	230	2,727
19	Shahan 5-8 1 ALT	CRK	6,880	115	222	2,727
20	Holmes 29-32 HC 1 ALT	CRK	7,334	121	231	2,721
21	PCK 13&24&25 HC 1H	CHK	7,140	N/A	N/A	2,700
22	Horn 8-17 2 ALT	CRK	8,301	140	248	2,386
23	PKY 35&26&23-14-15 HC 2 ALT	CHK	5,941	252	426	2,317
24	PKY 26&35-14-15 HC 3 ALT	CHK	5,294	209	423	2,270
25	QP 3&34&27-12-12 1H ALT	CHK	6,259	220	327	2,267

Activity Map

2

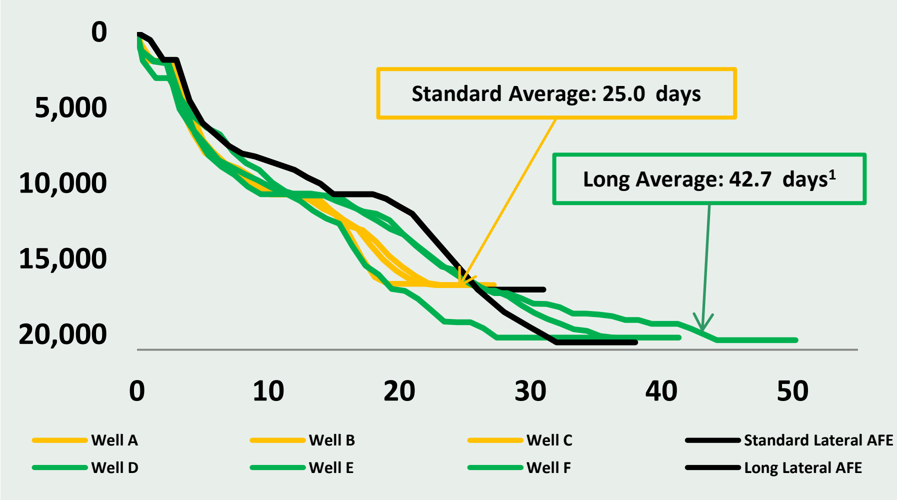


Multiple operators, including EXCO, have successfully utilized increased proppant loading to increase well productivity

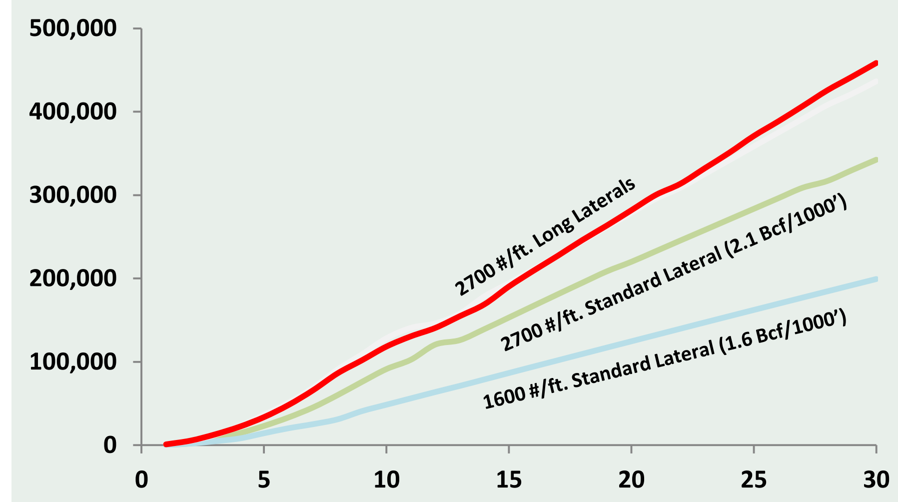
Source: IHS, PLS, rigdata.com, haynesvilleplay.com, public filings and company materials.

EXCO's Recent Results in North Louisiana

NLA Drilling Days Versus Depth
16; ft, Days
1



Cumulative Gas vs. Time
16; Cumulative Production, Days
2



Key Takeaways
3

- Standard length laterals drilled in Q2 2016 set company records, averaging 25 days from spud to rig release
- Record low D&C cost of $5.8 mm/well for standard laterals
- First three long laterals averaged 43 days with expected D&C cost of $8.5 mm/well
- Long lateral program will be drilled with rigs that have 7,500 psi rated pumps to improve rate of penetration

Key Takeaways
4

- EXCO's first three long laterals with ~2,700 lbs./ft. have IP'd ~21 Mmcf/d with ~7,900 psi flowing pressure, exceeding the company's expectations
- Larger completion designs with 2,700 lbs./ft. are demonstrating breakthroughs in well performance
- Current type curve IP is 16 Mmcf/d
- Wells are guided to 20-25 psi/d pressure drop

1. One cross-unit long lateral well experienced an exceptionally high number of MWD failures resulting in additional time on location.

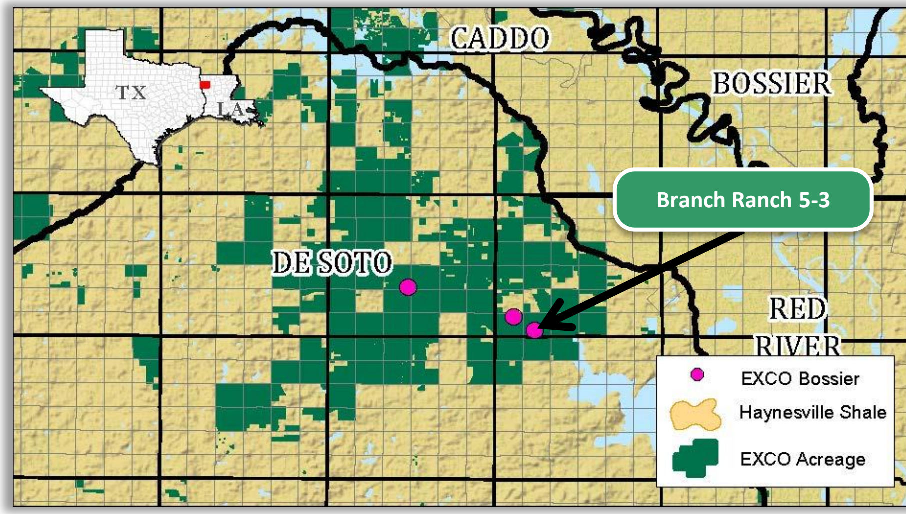
The North Louisiana Bossier Test Was A Success And Provides Future Opportunity

Operational Highlights 1

Key Developments

- Successfully completed and turned to sales the Branch Ranch 5-3 Bossier test well in January 2015
- The new well was EXCO's first operated Bossier shale well in North Louisiana since 2010 and utilized new rate restriction program and enhanced completion methods with standard lateral length
- The well is outperforming two previous Bossier wells with smaller completion designs
- 100% HBP position allows EXCO to defer development to high price environment
- EXCO's inventory includes 168 gross Bossier locations utilizing 7,500' lateral lengths
- Breakeven price of $3.02/Mcf

Area Of Operations 2



Key Takeaways 3

- Only three Bossier horizontal wells in EXCO NLA position
- Longer lateral design with larger completions will enhance economics in the Bossier, similar to the Haynesville
- Extensive infrastructure in place
- Large 168 well inventory

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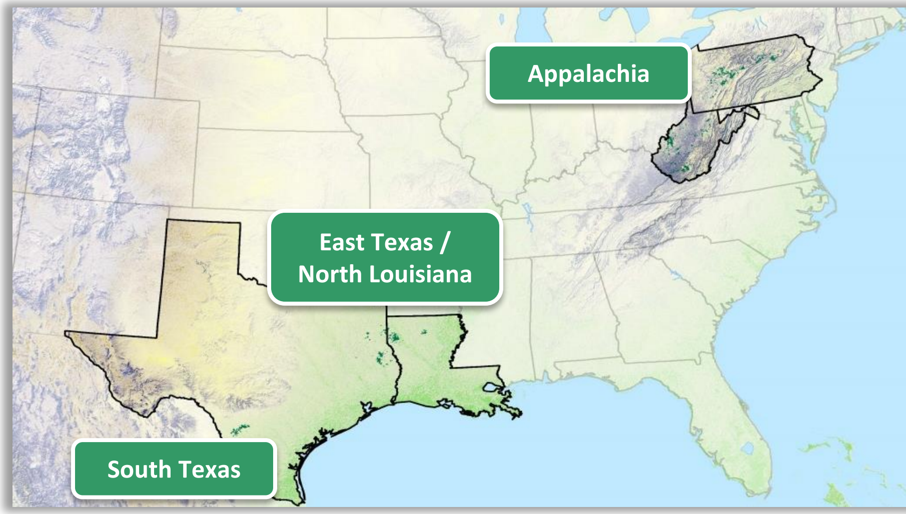
EXCO Overview: Three Concentrated Shale Resource Positions

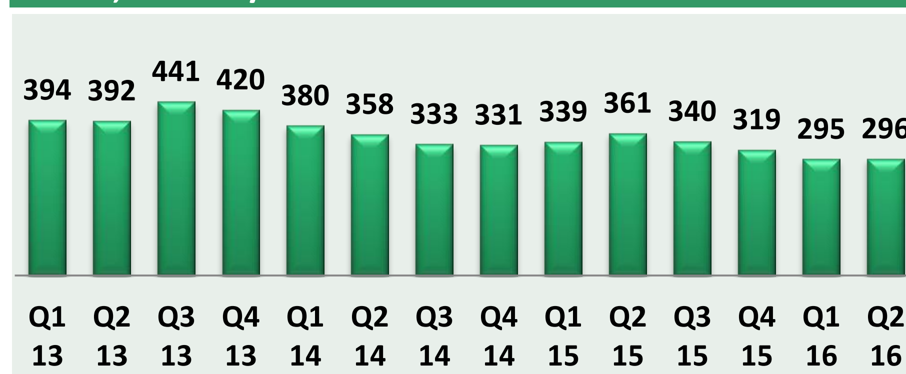
Operating Area Overview 1

East Texas And North Louisiana (Haynesville and Bossier)	
Net Acres/%HBP[1]	97,300/88%
Q2 '16 Operated Rigs (none currently)	1
Q2 '16 Net Production (Mmcfe/d)	222
6/30/16 Proved Reserves (Bcfe)[2]	1,101
South Texas (Eagle Ford)	
Net Acres/% HBP[1]	54,250/93%
Q2 '16 Operated Rigs	0
Q2 '16 Net Production (Boe/d)	5,400
6/30/16 Proved Reserves (Bcfe)[2]	146
Appalachia And Other (Marcellus, Utica and Upper Devonian)	
Net Acres/% HBP[1]	201,800/89%
Q2 '16 Operated Rigs	0
Q2 '16 Net Production (Mmcfe/d)	43
6/30/16 Proved Reserves (Bcfe)[2]	277
Total	
Net Acres/% HBP[1]	353,350/89%
Q2 '16 Operated Rigs	1
Q2 '16 Net Production (Mmcfe/d)	296
6/30/16 Proved Reserves (Bcfe)[2]	1,523
R/P, years	14.1

Core Basins 2



Net Production[3] 13-16; Mmcfe/d 3



EXCO is a leading shale producer that has drilled over 800 horizontal shale wells since 2008, participated in 269 horizontal wells operated by others and is well positioned to develop large inventory of 643 horizontal operated locations

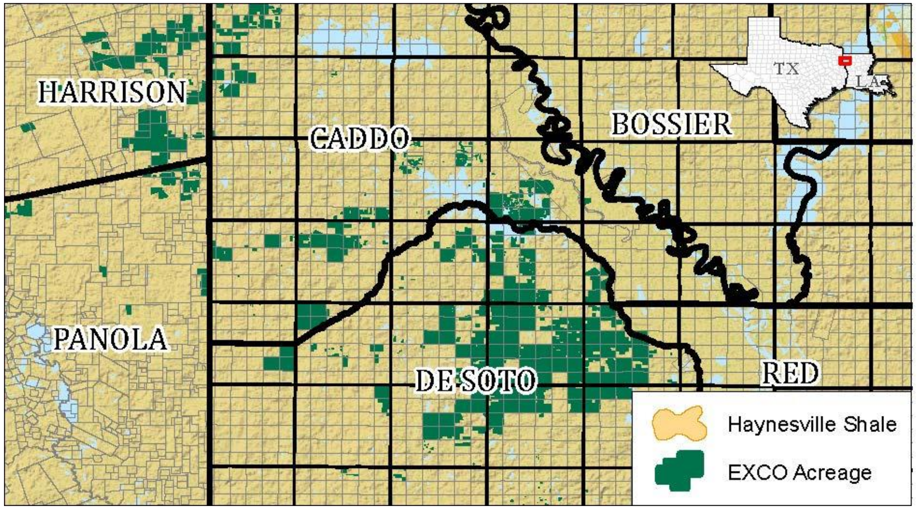
1. As of July 31, 2016.
2. Based on ten year June 30, 2016 strip prices and pro forma for recent divestiture of assets in Pennsylvania and STX settlement.
3. Net production excludes production from divested assets.

North Louisiana Overview

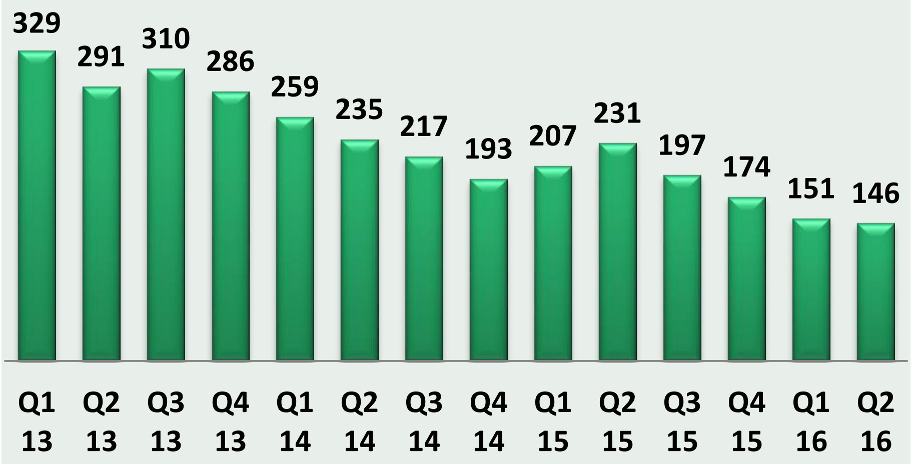
Operating Area Overview 1

Attribute	Key Features
Total Acreage[1]	• 51,500 net acres (38,000 shale) • 100% HBP
Active Wells	• 416 operated wells flowing to sales
Production	• Q2 '16: 146 Mmcfe/d
Targeted Formations	• Haynesville • Bossier
Highlights	• Leading Haynesville driller and producer in North Louisiana • Unparalleled basin area knowledge • Re-initiated drilling in the area in late 2015 • Inventory of 265 (gross) immediately executable drilling projects • On the forefront of re-frac application and emerging Bossier development
Q2 '16 Results	• Drilled 1 gross (0.9 net) operated Haynesville well in Q2 '16 • Turned-to-sales 3 gross (2.5 net) wells in the Haynesville shale with average costs of $5.8mm, a 22% decrease from prior year • Record low well cost despite larger stimulation design of 2,700 lbs/ft • The 3 wells turned to sales in Q2 '16 have estimated ultimate recoveries (EUR) of 2.1 Bcf per 1,000 lateral ft

Area Of Operations 2



Net Production 13-16; Mmcfe/d 3

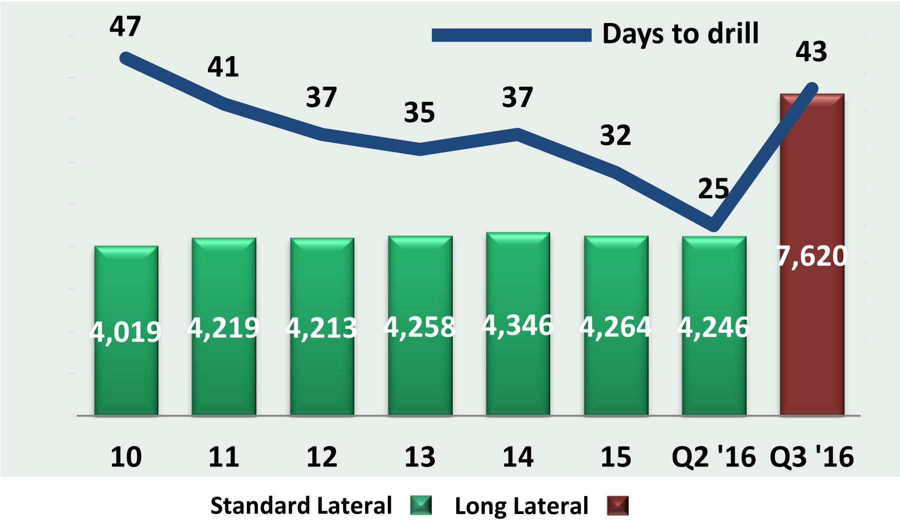


1. As of July 31, 2016.

Improve Economics Through Disciplined Execution And Cost Reductions

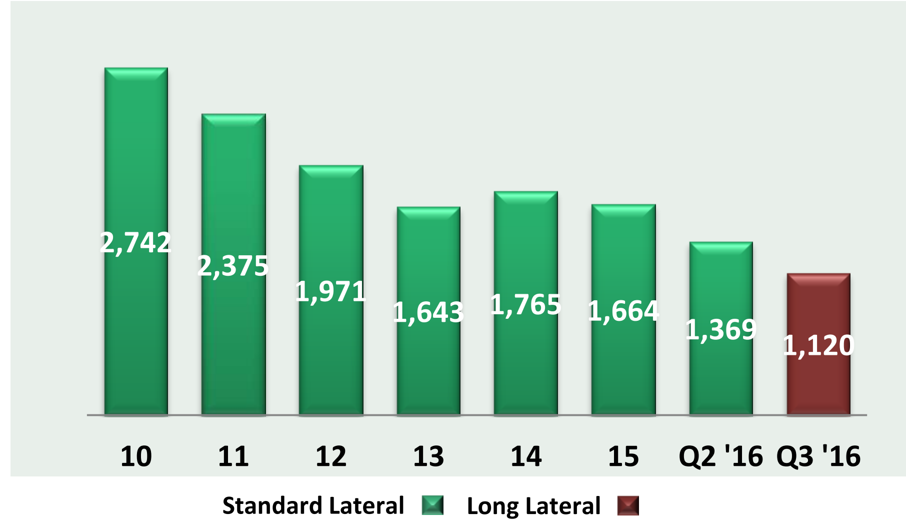
NLA Lateral Length And Days To Drill
10-16; ft, Days

1



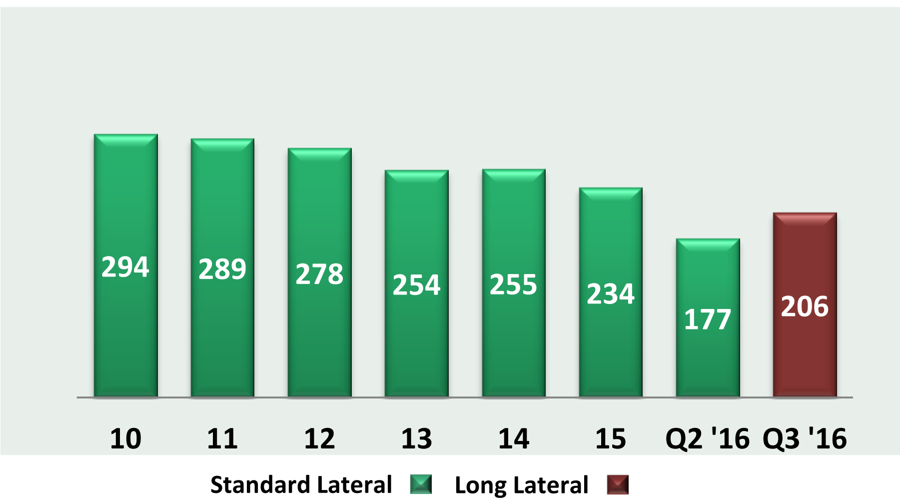
NLA D&C Cost Per Lateral Foot
10-16; $/ft

2



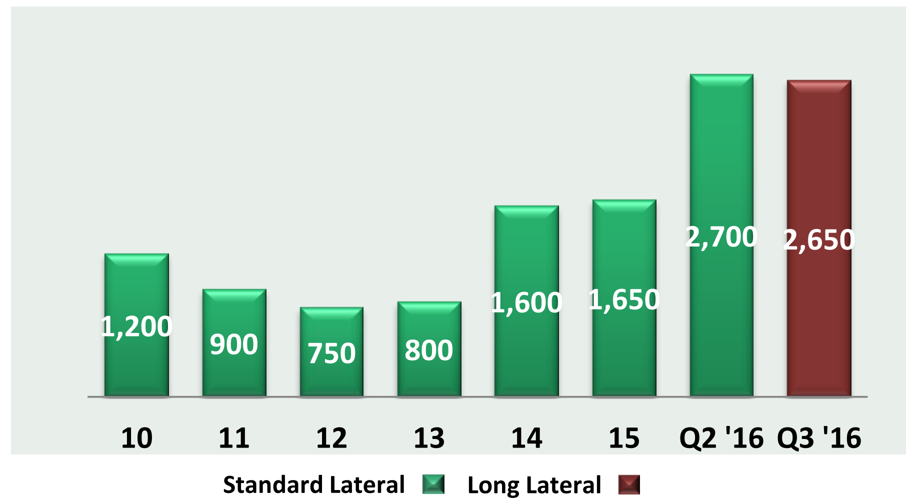
NLA Drilling Cost Per Foot
10-16; $/ft

3



NLA Proppant Per Lateral Foot
10-16; lbs/ft

4



EXCO has a strong track record of reducing costs and improving operational efficiencies; recent long laterals are the lowest cost per lateral foot that EXCO has achieved in the play[1]

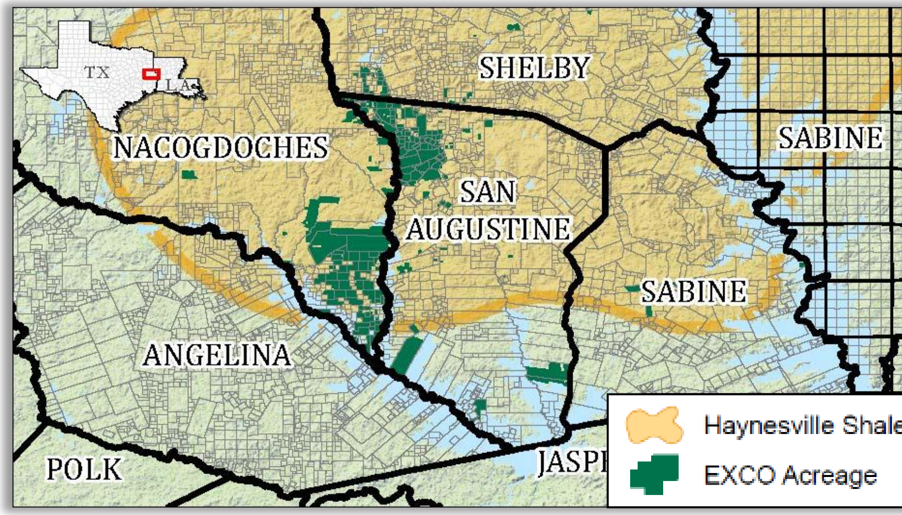
1. NLA D&C cost of 1,120 $/ft.

East Texas Overview

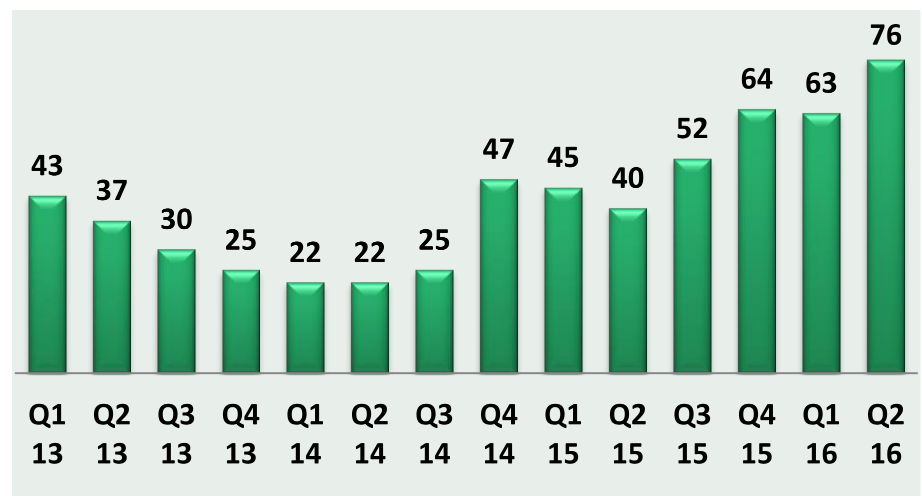
Operating Area Overview 1

Attribute	Key Features
Total Acreage[1]	• 45,800 net acres • 74% HBP
Active Wells	• 104 operated wells flowing to sales
Production	• Q2 '16: 76 Mmcfe/d
Targeted Formations	• Haynesville • Bossier
Highlights	• Transferred D&C expertise and capabilities to this area and re-engaged development activities in 2014 • Developed an inventory of 291 (gross) high return drilling projects; these projects represent a significant component of EXCO's near term growth engine • Other operators in Shelby area are XTO and BP, both with current rig activity • Larger stimulation design and modified well spacing have increased proved reserves from 1.3 to 1.5 Bcf per 1,000 lateral ft
Q2 '16 Results	• Most recent two wells drilled and completed have estimated ultimate recoveries (EUR) in excess of 2.0 Bcf per 1,000 lateral ft

Area Of Operations 2



Net Production 13-16; Mmcfe/d 3

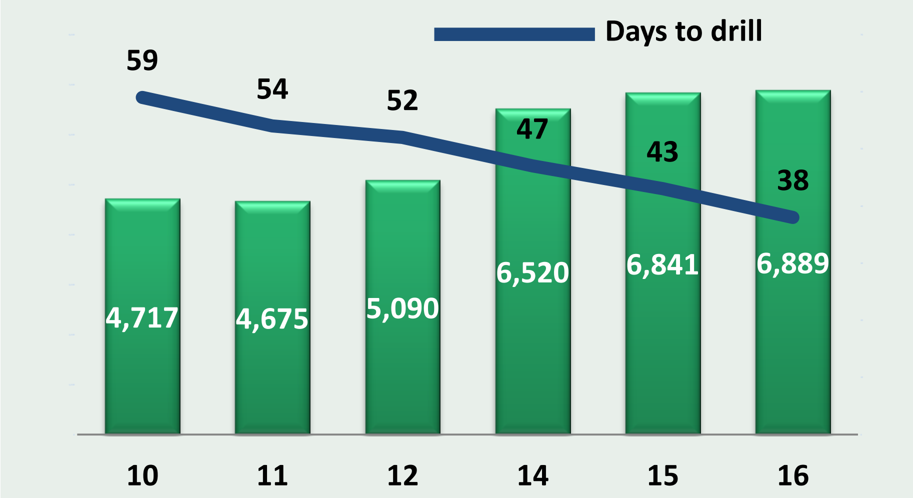


1. As of July 31, 2016.

Improve Economics Through Disciplined Execution And Cost Reductions

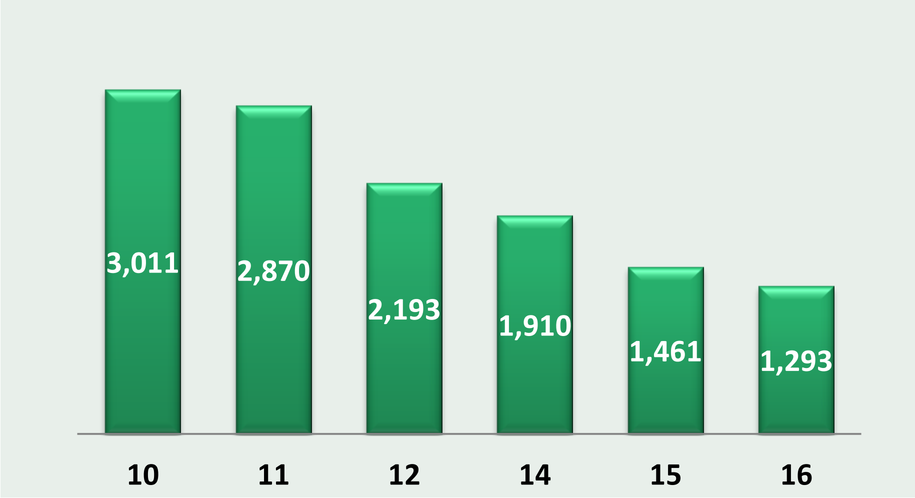
ETX Lateral Length And Days To Drill
10-16; ft; Days

1



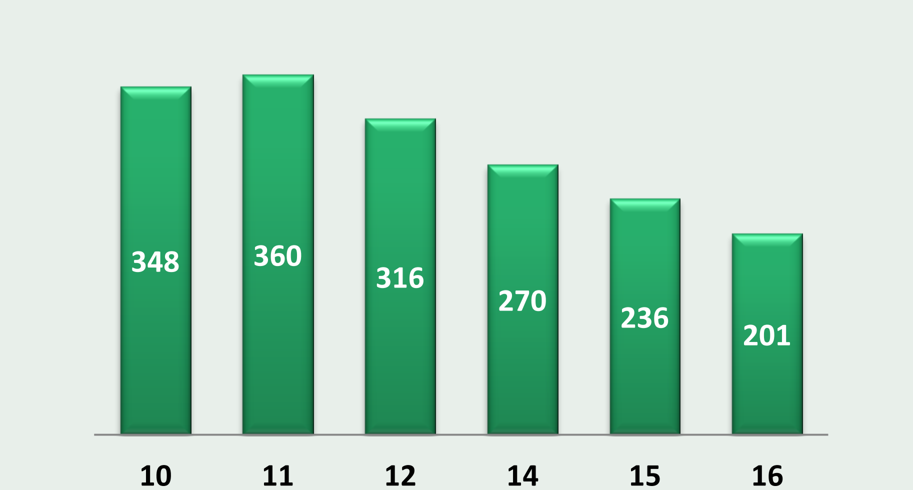
ETX D&C Cost Per Lateral Foot
10-16; $/ft

2



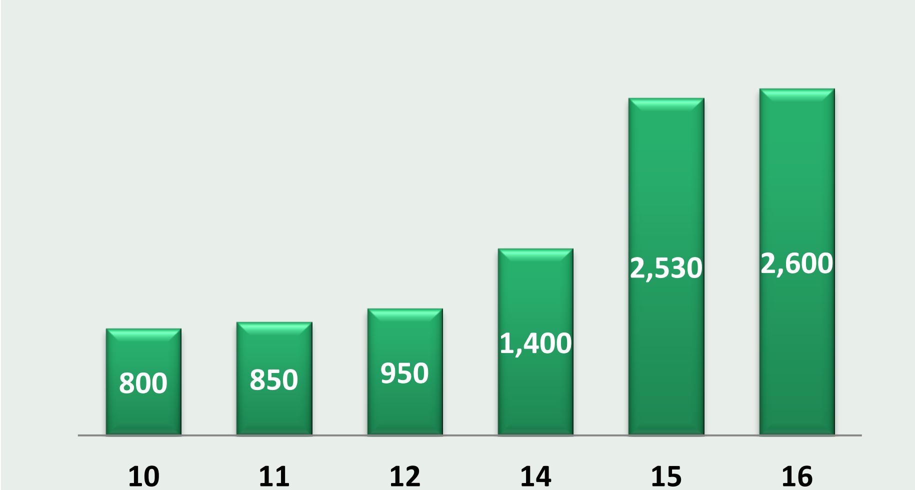
ETX Drilling Cost Per Foot
10-16; $/ft

3



ETX Proppant Per Lateral Foot
10-16; lbs/ft

4



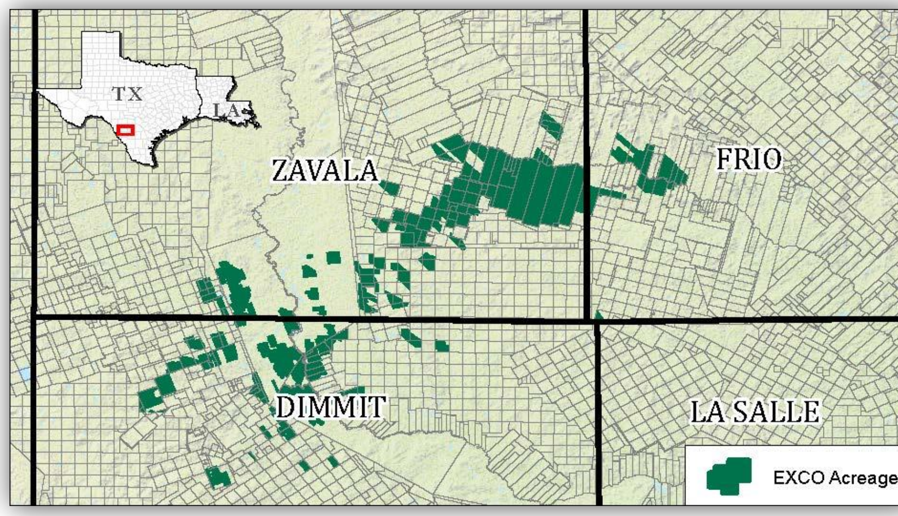
EXCO has a strong track record of reducing costs and improving operational efficiencies

South Texas Overview

Operating Area Overview 1

Attribute	Key Features
Total Acreage[1]	• 54,250 net acres • 93% HBP
Active Wells	• 235 operated wells
Production	• Q2 '16: 5.4 MBoe/d
Targeted Formations	• Eagle Ford
Highlights	• HBP acreage preserves inventory of 87 (gross) drilling projects
Q2 '16 Results	• No development activity during Q2 '16 • Re-engaging in STX with one rig program beginning in October • Acreage position is largely held-by-production, providing flexibility in timing of development • Transferred ~350 bbls/d through settlement agreement with a partner to allow for additional development flexibility and relieve certain obligations • Transitioned from Tier 2 to Tier 1 Type Curve post recent non-core acreage divestiture and settlement agreement with JV partner • Renegotiated contracts to reduce salt water disposal and chemical costs • Improved realized price on oil production by $1.95 to $2.90 per Bbl through a bidding process with transportation providers

Area Of Operations 2



Net Production 13-16; Boe/d 3

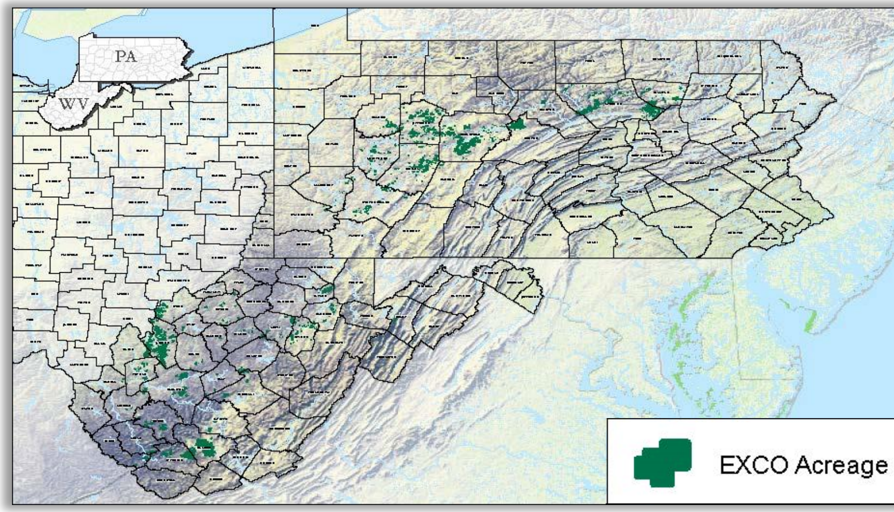
1. As of July 31, 2016.

Appalachia Overview

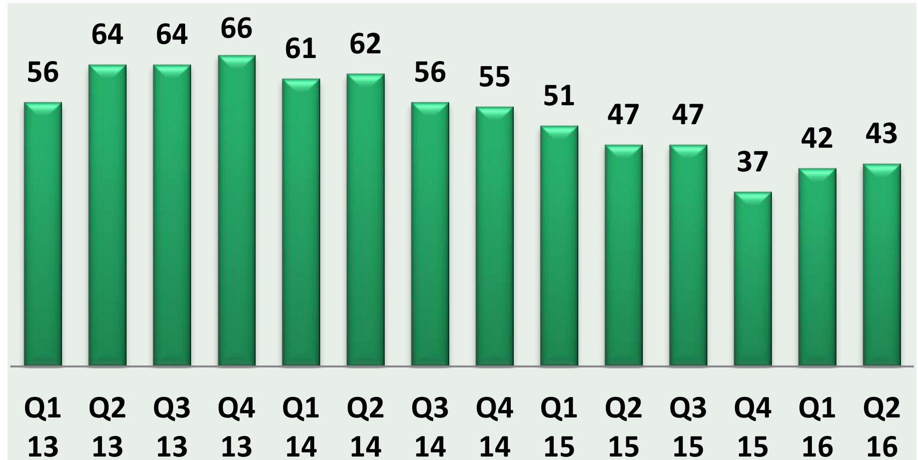
Operating Area Overview 1

Attribute	Key Features
Total Acreage[1]	• 201,800 net acres (130,400 shale) • 89% HBP (shale)
Active Wells	• 126 operated Marcellus wells flowing to sales • 1,986 conventional wells flowing to sales • Closed the sale of shallow conventional assets in Pennsylvania on July 1, '16, reducing conventional well count by 3,523
Production	• Q2 '16: 43 Mmcfe/d
Targeted Formations	• Marcellus • Utica and Upper Devonian
Highlights	• High HBP percentage extends tenor of EXCO's Marcellus and Utica gas option • Divestment of high cost conventional properties lowers EXCO's cost of carry
Q2 '16 Results	• Acreage position in the Marcellus shale is approximately 89% held-by-production, providing flexibility in timing of development • Reduced field employee count by 52% in conjunction with the July 1, '16 divestiture • EXCO holds 40,000 net acres that are well positioned in the emerging Utica shale dry gas play

Area Of Operations 2



Net Production 13-16; Mmcfe/d 3



1. As of July 31, 2016.

Agenda

- Executive Summary
- Haynesville Transformation
- EXCO Overview
- Appendix

Financial And Operational Results

Factors	Unit	Quarter-to-Date					Year-to-Date		
		2Q 16	1Q 16		2Q 15		2Q 16	2Q 15	
		Actual	Actual	% Change	Actual	% Change	Actual	Actual	% Change
Rig Count	#	1	2	(50)	4	(75)	1	4	(75)
Net Wells Drilled	#	0.9	4.3	(79)	4.4	(80)	5.2	9.9	(47)
Net Wells Turned To Sales	#	2.5	3.6	(31)	5.7	(56)	6.1	20.3	(70)
Production									
Oil	Mbbl	447	550	(19)	594	(25)	997	1,098	(9)
Natural Gas	Bcf	24.3	23.5	3	29.3	(17)	47.8	56.8	(16)
Total	Bcfe	27.0	26.8	1	32.9	(18)	53.8	63.4	(15)
Total Daily	Mmcfe/d	296	295	0	361	(18)	296	350	(15)
Realized Price Differentials									
Oil	$/Bbl	(5.04)	(5.23)	(4)	(4.65)	8	(5.15)	(5.71)	(10)
Natural Gas	$/Mcf	(0.46)	(0.55)	(16)	(0.52)	(12)	(0.50)	(0.56)	(11)
Financial Results									
Lease Operating Expense	$/Mcfe	0.28	0.35	(20)	0.43	(35)	0.32	0.46	(30)
Production Taxes	$/Mcfe	0.18	0.17	6	0.17	6	0.18	0.17	6
Gathering And Transportation	$/Mcfe	1.00	0.99	1	0.75	33	0.99	0.80	24
General And Administrative[1]	$MM	8	7	14	11	(27)	15	25	(40)
Interest Expense[2]	$MM	17	17	0	27	(37)	35	53	(34)
Adjusted EBITDA[3]	$MM	23	21	10	69	(67)	44	125	(65)
Capital Expenditures	$MM	19	37	(49)	75	(75)	56	178	(69)

1. Excludes equity-based compensation expenses of $9.3 mm, $3.8 million and $1.4 mm for the three months ended June 30, '16, March 31, '16 and June 30, '15, respectively, and $13.1 mm and $3.1 mm for the six months ended June 30, '16 and June 30, '15, respectively.
2. Interest expenses exclude the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the Exchange Term Loan are not considered interest expense per ASC 470-60 and are excluded from the cash interest expenses amounts shown. EXCO's expected payments on the Exchange Term Loan in '16 total $50.0 million.
3. Adjusted EBITDA is a non-GAAP measure. See appendix for definition and reconciliation.

Actuals To Guidance Comparison

Factors	Unit	Three Months Ended					Full Year 2016 Guidance	
		2Q 16	2Q 16 Guidance		3Q 16 Guidance			
		Actual	Low	High	Low	High	Low	High
Rig Count (Gross)	#	1	1		0		1	
Wells Drilled (Gross/Net)	#	1/0.9	1/0.9		0/0		7/5.4	
Wells Turned To Sales (Gross/Net)	#	3/2.5	6/5.6		3/2.7		15/9.0	
Production								
Oil	Mbbl	447	470	490	375	395	1,720	1,740
Natural Gas	Bcf	24.3	24.5	25.3	23.0	23.9	92.2	99.4
Total	Bcfe	27.0	27.3	28.2	25.3	26.2	102.5	109.8
Total Daily	Mmcfe/d	296	300	310	275	285	280	300
Realized Price Differentials								
Oil	$/Bbl	(5.04)	(4.00)	(6.00)	(3.00)	(5.00)	(3.50)	(5.50)
Natural Gas	$/Mcf	(0.46)	(0.60)	(0.70)	(0.50)	(0.60)	(0.50)	(0.60)
Financial Results								
Lease Operating Expense	$/Mcfe	0.28	0.35	0.40	0.35	0.40	0.35	0.40
Production Taxes	$/Mcfe	0.18	0.15	0.20	0.15	0.20	0.15	0.20
Gathering And Transportation	$/Mcfe	1.00	0.95	1.00	1.00	1.05	1.00	1.05
General And Administrative[1]	$MM	8	6	7	9	10	30	35
Interest Expense[2]	$MM	17	17	19	16	18	60	65

1. Excludes equity based compensation expense.
2. Interest expenses exclude the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the Exchange Term Loan are not considered interest expense per ASC 470-60 and are excluded from the cash interest expenses amounts shown. EXCO's expected payments on the Exchange Term Loan in '16 are $50.0mm.

Hedge Positions (Including Trades Since June 30)

Factors	Unit	Six Months Ended 12/31/16		Twelve Months Ended 12/31/17		Twelve Months Ended 12/31/18	
		Volume	Price	Volume	Price	Volume	Price
Natural Gas							
Fixed Price Swaps - Henry Hub	Bbtu, $/Mmbtu	28,520	2.88	23,700	2.99	3,650	3.15
Fixed Price Swaptions - Henry Hub[2]	Bbtu, $/Mmbtu	-	-	7,300	2.76	-	-
Collars - Henry Hub	Bbtu			10,950			
Sold Call Options	$/Mmbtu				3.28		
Purchased Put Options	$/Mmbtu				2.87		
Oil							
Fixed Price Swaps - WTI	Mbbl, $/Bbl	552	58.61	183	50.00	-	-
Percent Hedged[1]							
Natural Gas	%	66		66		9	
Oil	%	66		13		-	

1. Percent hedged based upon PDP production forecast and includes swaption volumes.
2. Exercisable on December 22, '16.

Appendix: Single Well Economics – Internal Type Curves

		Unit	NLA DeSoto Core	NLA Caddo X-Unit Lateral	NLA Caddo Standard Lateral	NLA Bossier X-Unit Lateral	ETX Shelby HSVL	ETX Shelby Bossier	ETX Highlander	STX Eagle Ford Core Tier 1	STX Eagle Ford Core Tier 2
1	Target Lateral Length	Ft	4,500	7,500	4,500	7,500	7,500	7,500	6,500	7,500	7,500
2	Gross Locations	#	24	52	21	168	71	97	123	49	38
3	Net Locations	#	9	13	8	78	29	41	30	14	18
4	WI	%	39	25	37	47	42	42	25	39	47
5	NRI	%	30	19	29	37	32	32	19	31	35
6	Spacing	Acres	136	227	136	227	207	207	224	172	172
	Type Curve										
7	IP	Mcf/d	16,000	16,000	12,000	10,000	9,400	9,400	11,500	500	420
8	Phase I – Duration Month	Month	16	18	18	12	14	14	18	15	4
9	Phase I – B Factor	x	0	0	0	0	0.6	0.6	0	1.25	1.25
10	Phase I – Initial Decline	%	60	40	52	41	22	22	41	61	85
11	Phase II – Duration Month	Month	n/a	n/a	n/a	n/a	7	7	n/a	n/a	4
12	Phase II – B Factor	x	1	1	1	1	0.6	0.6	1	1.25	1.25
13	Phase II – Initial Decline	%	57.1	66.2	64.5	55	42	42	42.5	35	35
14	Phase III – Initial Decline	%	n/a	n/a	n/a	n/a	33	33	n/a	n/a	46.5
15	Terminal Decline	%	6	6	6	6	6	6	6	6	6
16	Wellhead EUR	Bcf/Mbo	9.5	12	7.2	9.6	13	13	13	535	392
17	EUR per 1,000' (lateral length)	Bcf or Mbo	2.1	1.6	1.6	1.28	1.75	1.75	2	71	52
18	D&C/Pumping Unit	$MM	6.0	8.0	6.0	8.4	9.2	9.5	10.3	3.8/0.275	3.8/0.275
19	LOE Fixed - WI	$/month	1,876	1,876	1,876	2,465	2,922	2,922	2,711	8,914	7,249
20	Variable/Gathering Expense - WI	$/Mcf,$/Bbl	.02/.44	.02/.44	.02/.44	.02/.44	0.03/0.29	0.03/0.29	0.02/0.31	0.03/0.0	0.16/0.0
	Single Well Returns										
21	PV10 (8/8ths)[1]	$MM	4.8	5.1	2.6	1.7	6.1	5.8	3.9	3.1	2.2
22	IRR[1]	%	87	63	48	20	42	39	27	49	35
23	Breakeven Flat Price (25% IRR)	$/Mmbtu	2.19	2.35	2.53	3.02	2.62	2.70	3.02	44.25	47.00
24	PV/I, Disc	X	1.81	1.64	1.44	1.20	1.67	1.62	1.38	1.76	1.56

1. Economics based on June 30, 2016 strip prices through 2021 and held flat thereafter at $3.19 per Mcf for Henry Hub Natural Gas and $56.31 for WTI Oil.

Appendix: June 30, 2016 Price Deck

	Henry Hub Natural Gas Prices	WTI Crude Oil Prices
Year	$/Mcf	$/Bbl
2016	3.03	48.85
2017	3.18	52.40
2018	3.02	53.81
2019	3.00	54.69
2020	3.06	55.51
2021	3.19	56.31
2022	3.35	57.04
2023	3.53	57.86
2024	3.70	57.86
2025	3.88	57.86
Terminal	3.88	57.86

Appendix: Detailed Description of EXCO's Restricted Cash Position

EXCO's Restricted Cash Position

Restricted cash is principally comprised of EXCO's share of an evergreen escrow account with BG Group/Shell that is used to fund the company's share of development operations in East Texas and North Louisiana. Funds held in this escrow account are restricted and can be used primarily for drilling and operations in East Texas and North Louisiana. The restricted cash also includes accrued fees payable to Energy Strategic Advisory Services LLC ("ESAS") upon completion of its entire first year of service and required investment with EXCO.

EBITDA, Adjusted EBITDA, Adjusted Operating Cash Flow and Free Cash Flow Reconciliations

	Three Months Ended			Six Months Ended	
(in thousands)	June 30, 2016	March 31, 2016	June 30, 2015	June 30, 2016	June 30, 2015
Net loss	$ (111,347)	$ (130,148)	$ (454,155)	$ (241,495)	$ (772,267)
Interest expense	17,932	19,257	25,571	37,189	53,061
Income tax expense	747	—	—	747	—
Depletion, depreciation and amortization	19,084	29,001	61,658	48,085	124,147
EBITDA (1)	$ (73,584)	$ (81,890)	$ (366,926)	$ (155,474)	$ (595,059)
Accretion of discount on asset retirement obligations	769	912	568	1,681	1,124
Impairment of oil and natural gas properties	26,214	134,599	394,327	160,813	670,654
Other items impacting comparability	24,296	402	2,897	24,698	3,501
Gain on extinguishment of debt	(16,839)	(45,114)	—	(61,953)	—
Equity loss	91	7,910	535	8,001	1,300
(Gain) loss on derivative financial instruments	36,432	(16,591)	6,631	19,841	(17,079)
Cash receipts of derivative financial instruments	16,598	16,790	29,401	33,388	57,039
Equity-based compensation expense	9,328	3,813	1,439	13,141	3,119
Adjusted EBITDA (1)	$ 23,305	$ 20,831	$ 68,872	$ 44,136	$ 124,599
Interest expense	(17,932)	(19,257)	(25,571)	(37,189)	(53,061)
Current income tax expense	—	—	—	—	—
Amortization of deferred financing costs and discount	1,878	3,121	2,099	4,999	6,975
Other operating items impacting comparability and non-operating items	875	(422)	(2,897)	453	(3,501)
Changes in working capital	9,818	23,708	9,171	33,526	33,192
Net cash provided by operating activities	$ 17,944	$ 27,981	$ 51,674	$ 21,494	$ 108,204

	Three Months Ended			Six Months Ended	
(in thousands)	June 30, 2016	March 31, 2016	June 30, 2015	June 30, 2016	June 30, 2015
Cash flow from operations, GAAP	$ 17,944	$ 27,981	$ 51,674	$ 45,925	$ 108,204
Net change in working capital	(9,818)	(23,708)	(9,171)	(33,526)	(33,192)
Other operating items impacting comparability	—	402	2,897	402	3,501
Adjusted operating cash flow, non-GAAP measure (2)	$ 8,126	$ 4,675	$ 45,400	$ 12,801	$ 78,513

	Three Months Ended			Six Months Ended	
(in thousands)	June 30, 2016	March 31, 2016	June 30, 2015	June 30, 2016	June 30, 2015
Cash flow from operations, GAAP	$ 17,944	$ 27,981	$ 51,674	$ 45,925	$ 108,204
Less: Additions to oil and natural gas properties, gathering assets and equipment	(22,477)	(32,486)	(83,712)	(54,963)	(204,600)
Free cash flow, non-GAAP measure (3)	$ (4,533)	$ (4,505)	$ (32,038)	$ (9,038)	$ (96,396)

(1) Earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") represents net income (loss) adjusted to exclude interest expense, income taxes and depreciation, depletion and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivatives, non-cash impairments of assets, equity-based compensation, income or losses from equity method investments, legal settlements and other operating items impacting comparability. In previous periods, the Company added back severance costs in the determination of Adjusted EBITDA. As a result of a reduction in workforce that occurred in the second quarter 2016, management reassessed this measurement and determined it is no longer considered non-recurring. Accordingly, all periods for which Adjusted EBITDA is presented exclude an adjustment for severance costs. EXCO has presented EBITDA and Adjusted EBITDA because they are measures widely used by investors, analysts and rating agencies for valuations, peer comparisons and investment recommendations. In addition, similar measures are used in covenant calculations required under the Credit Agreement, the indenture governing the 2018 Notes, the indenture governing the 2022 Notes and the term loan credit agreements governing the 12.5% senior secured second lien term loans due on October 26, 2020 ("Second Lien Term Loans"). Compliance with the liquidity and debt incurrence covenants included in these agreements is considered material to the Company. EXCO's computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies due to differences in the inclusion or exclusion of items in the Company's computations as compared to those of others. EBITDA and Adjusted EBITDA are measures that are not prescribed by GAAP. EBITDA and Adjusted EBITDA specifically exclude changes in working capital, capital expenditures and other items that are set forth on a cash flow statement presentation of the Company's operating, investing and financing activities. As such, investors are encouraged not to use these measures as substitutes for the determination of net income, net cash provided by operating activities or other similar GAAP measures. The calculation of EBITDA and Adjusted EBITDA as presented herein differ in certain respects from the calculation of comparable measures in the Credit Agreement, the indenture governing the 2018 Notes, the indenture governing the 2022 Notes and the term loan credit agreements governing the Second Lien Term Loans.

(2) Adjusted operating cash flow is presented because the Company believes it is a useful financial indicator for companies in its industry. This non-GAAP disclosure is widely accepted as a measure of an oil and natural gas company's ability to generate cash used to fund development and acquisition activities and service debt or pay dividends. Adjusted operating cash flow is not a measure of financial performance pursuant to GAAP and should not be used as an alternative to cash flows from operating, investing, or financing activities. Other operating items impacting comparability have been excluded as they do not reflect the Company's on-going operating activities. All periods for which Adjusted operating cash flow is presented include severance costs.

(3) Free cash flow is cash provided by operating activities less capital expenditures. This non-GAAP measure is used predominantly as a forecasting tool to estimate cash available to fund indebtedness and other investments.

Rates of return are based on NYMEX futures prices as of June 30, 2016, including natural gas prices per Mmbtu of $3.01 for 2016, $3.18 for 2017, $3.02 for 2018, $3.00 for 2019, $3.08 for 2020, and $3.19 thereafter, and oil prices per Bbl of $49.95 for 2016, $52.40 for 2017, $53.81 for 2018, $54.69 for 2019, $55.51 for 2020, and $56.31 thereafter. The rates of return are presented before the impact of income taxes.