First Quarter 2017 Review

Hal Hickey	Chief Executive Officer
Harold Jameson	Chief Operating Officer
Tyler Farquharson	Chief Financial Officer

May 10, 2017

Strategic Plan Update

Focus Area	#	Improvement Plan	Update
Liability Management	1	Improve Debt Structure To Provide Structural Liquidity	• Issued \$300MM in new 1.5 Lien Notes and exchanged \$683MM in existing 2nd Lien Term Loans for new 1.75 Lien Term Loans. These instruments allow for the Company to pay interest in either cash, common shares or additional debt • Improved liquidity by \$120 million in Q1 ‘17 compared to Q4 ‘16 through issuance of new indebtedness and exchange of existing indebtedness • Credit Agreement amended to establish a borrowing base of \$150MM (undrawn at March 31, ‘17); amendments allow for the issuance of 1.5 Lien Notes and 1.75 Lien Term Loans and modification of certain covenants • Continuing to evaluate repurchases of 2018 and 2022 unsecured notes. The Company has \$132MM outstanding on its 2018 Notes and \$70MM outstanding on its 2022 Notes
	2	Restructure Gathering And Transportation Contracts To Provide Liquidity	• Negotiating with midstream and transportation providers to restructure gathering and transportation contracts
Operational Performance	3	Reduce LOE and G&A Load To Reduce Fixed Cost Burden	• Decreased LOE costs by 11% in Q1 ‘17 compared to Q4 ‘16 • Reduced total employee headcount approximately 41% since Q1 ‘16
	4	Improve Drilling And Completion Performance To Improve Capital Returns	• Enhanced completions in the Haynesville with 2,700 lbs/ft have improved EUR/ft to 2.3 Bcf/1,000 ft in NLA and to 2.6 Bcf/1,000 ft in ETX • Company is implementing larger completion designs with higher fracture intensity and tighter cluster spacing in 2017, increasing proppant amount from 2,700 to 3,500 lbs/ft • North LA Bossier appraisal test with long lateral and enhanced completion design recently TTS; plan to drill four additional Bossier appraisal wells in 2017 to evaluate opportunity and unlock upside
Capital Deployment	5	Implement A “Liquidity Driven” Prioritized Capital Allocation System To Ensure Highest And Best Use Of Capital	• Increased ‘17 capital budget to \$158MM versus capital spend of \$78MM in ‘16 • Measuring capital allocation decisions against liquidity intensity benchmark • Executed agreement to sell South Texas asset. Proceeds from divestiture will primarily be deployed to high rate of return opportunities in the Haynesville and Bossier shales. Borrowing base on credit agreement will be reduced to \$100MM following the closing of the sale

Shareholder Approval and NYSE Update

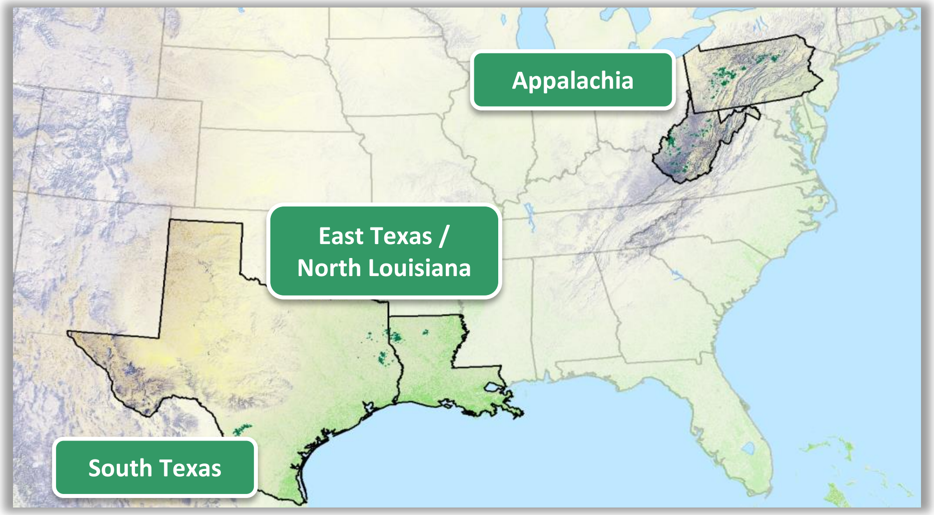
	Issue	Requirements/Considerations
1	Recent Capital Transactions	• NYSE 1% Rule: Requires consent of shareholders if a related party (director, officer and holder of more than 5% of outstanding shares) is issued in excess of 1% of the total outstanding number of shares • NYSE 20% Rule: Requires consent of shareholders if the total equity issued exceeds 20% of the outstanding common stock • Transaction was structured to allow deal to close and fund before achieving shareholder approval • Defer PIK into equity until shareholder approval is received, but the Company does have the ability to PIK with debt • Company is recommending shareholders approve the issuance of shares for PIK feature of transaction • Annual meeting set for May 31, ‘17
2	Reverse Share Split	• Company received a notice of non-compliance from NYSE in January 2017 because average closing share price was less than $1.00 for a consecutive 30 trading-day period • Company is seeking shareholder approval to give Board of Directors authority for a reverse share split in a range of 1-for-10 to 1-for-20 • Reverse share split will cure share price compliance issue and allow Company to continue to be listed on NYSE • As part of the reverse share split, the Company will seek less than a proportionate reduction of its authorized common shares. The proposal will permit a 1/5th reduction in proportion to the reverse share split ratio. The additional authorized common shares will allow the Company to use the PIK into common shares provisions of the 1.5 Lien Notes and 1.75 Lien Term Loans. • Requires 2/3rds approval of outstanding shares for the reverse share split

EXCO Overview: Three Concentrated Resource Positions

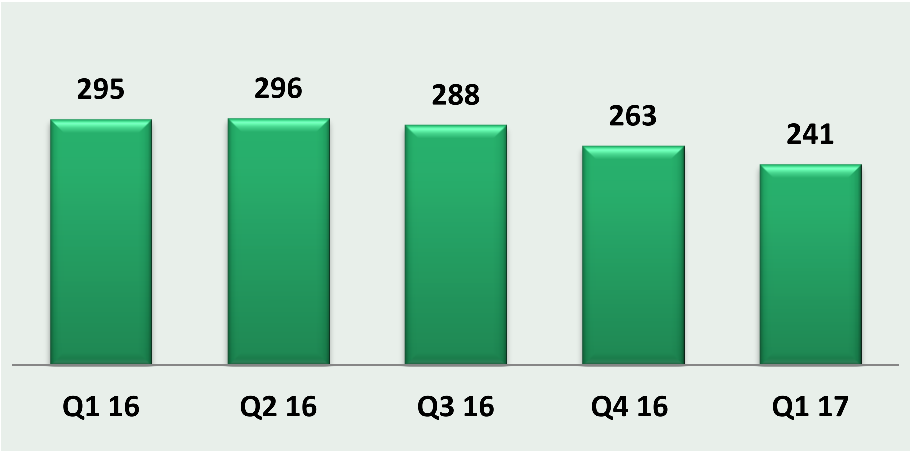
Operating Area Overview 1

East Texas and North Louisiana	
Net Acres/%HBP[1]	96,300/87%
Q1 '17 Operated Rigs[2]	1-3
Q1 '17 Net Production (Mmcfe/d)	187
12/31/16 Proved Reserves (Bcfe)[3]	1,110
South Texas	
Net Acres/% HBP[1]	49,300/95%
Q1 '17 Operated Rigs	0
Q1 '17 Net Production (Boe/d)	4,000
12/31/16 Proved Reserves (Bcfe)[3]	155
Appalachia and Other	
Net Acres/% HBP[1]	184,100/93%
Q1 '17 Operated Rigs	0
Q1 '17 Net Production (Mmcfe/d)	30
12/31/16 Proved Reserves (Bcfe)[3]	238
Total	
Net Acres/% HBP[1]	329,700/92%
Q1 '17 Operated Rigs[2]	1-3
Q1 '17 Net Production (Mmcfe/d)	241
12/31/16 Proved Reserves (Bcfe)[3]	1,503

Core Basins 2



Net Production 16-17; Mmcfe/d 3



1. As of December 31, '16
2. Currently operating 4 rigs
3. Proved reserves were based on December 30, 2016 NYMEX futures prices, in each case adjusted for geographical and historical differentials. The NYMEX proved reserves disclosed differ from proved reserves that would be prepared based on the methodology prescribed by GAAP primarily due to the oil and natural gas prices and the development plans utilized in the classification of undeveloped locations. This measure should not be purported to be in accordance with GAAP nor is it indicative of the Company's proved reserves if they were prepared in accordance with GAAP

2017 Capital Budget

Capital Program Overview
17; Mixed Measures

1

Category	Descriptions
Drilling	• Currently running 4 rigs; plan to hold 4 rig program through 2017 • Drilling focused in NLA Haynesville for highest economic returns • NLA Bossier appraisal test with long lateral and enhanced completion design recently TTS; plan to drill four additional Bossier appraisal wells in 2017 to unlock upside
Completion	• 1-2 frac fleets • 3,500 lb/ft completion design with higher fracture intensity on new wells • 50% of the program consists of 7,500 ft laterals or longer • Program includes 4,500, 7,500 and 10,000 ft laterals
Non-Operated Activity	• Haynesville Non-op activity is moving higher (5x 2016 level) • Higher proppant tests, longer laterals and spacing tests will be considerations in well elections • East TX appraisal will continue in 2017 through participation in certain wells in the Shelby area
Land	• Land investment supports the 2017 drilling plans

Capital Budget By Type
17; $MM

2

Category	
Drilling and Completion[1]	137
Field Operations	4
Land	7
Corporate & Other[2]	10
Total	158

Drilling and Completion[3]
17; #

3

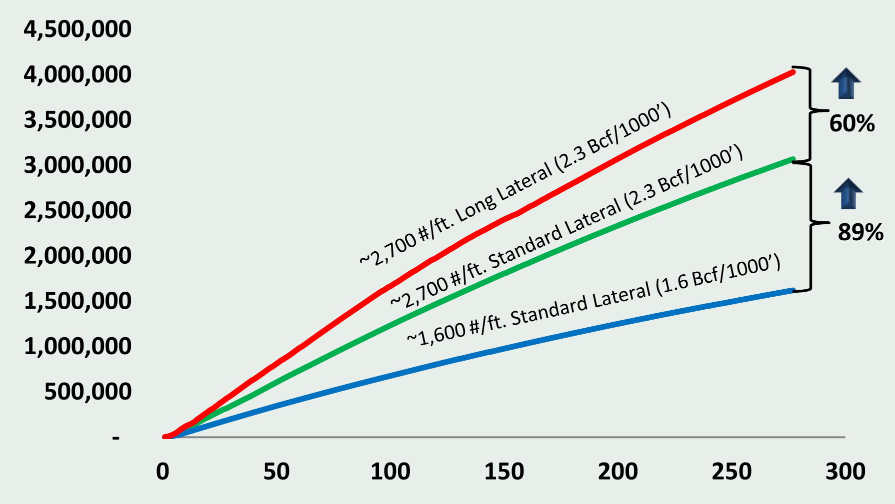
Area	Gross Spuds	Net Spuds	Gross Completions	Net Completions
North LA	38	15.9	26	11.1
Appalachia	0	0.0	1	0.5
Total	38	15.9	27	11.6

2017 program with 4 rigs focused on North LA to deliver highest returns in portfolio; spud 38 gross (15.9 net) EXCO operated wells

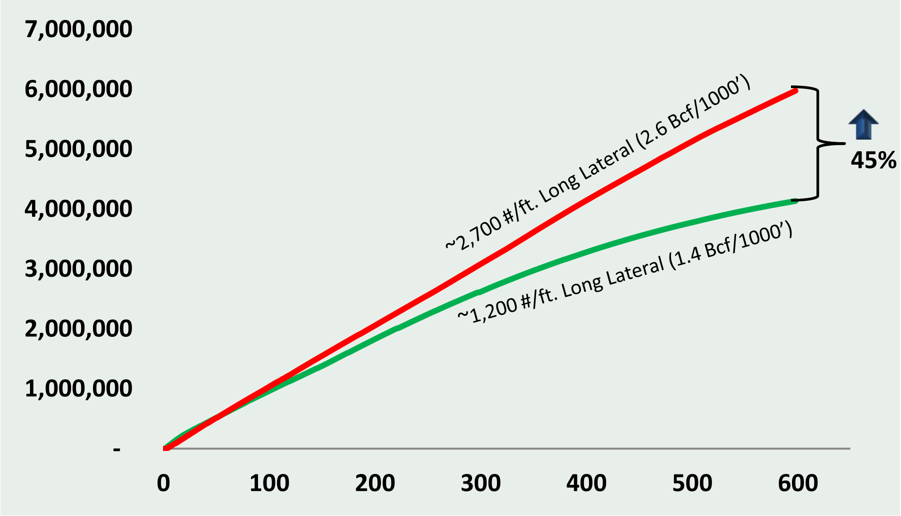
1. Includes $122 million of operated and $15 million of non-operated drilling and completion costs
2. Includes $5 million of capitalized interest and $4 million of capitalized general and administrative expenses
3. EXCO operated

Improve Drilling and Completion Performance to Improve Capital Returns

NLA Cumulative Gas vs. Time
Mcf; Days
1



ETX Cumulative Gas vs. Time
Mcf; Days
2

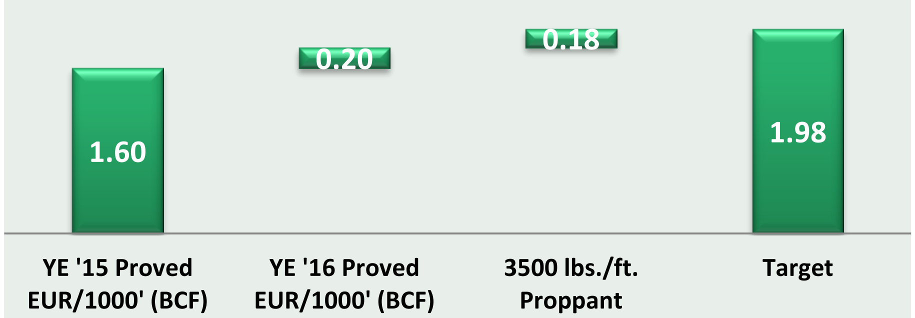


Well Performance
3

- Wells with ~2,700 lb/ft completions performance exceeding expectations
- Larger stimulation design having positive impact on existing wells
- Larger completions and longer laterals delivering 149% more volume in approximately 275 days on line in NLA
- Three long lateral wells in NLA turned-to-sales in Q3 '16 averaged $8.8MM/well
- Larger completions delivering 45% more volume in approximately 600 days online in ETX
- Most recent well TTS in the southern area of ETX in Q1 '16 cost $10.3MM. This well was drilled in the deepest part of the Haynesville play to a TVD of >14,500'

NLA Caddo 7,500' Type Curve Progression
2016+; Bcf/1000'
4

NPV-10 (8/8ths) of Target is $8.9MM, up from $6.9MM at YE '15

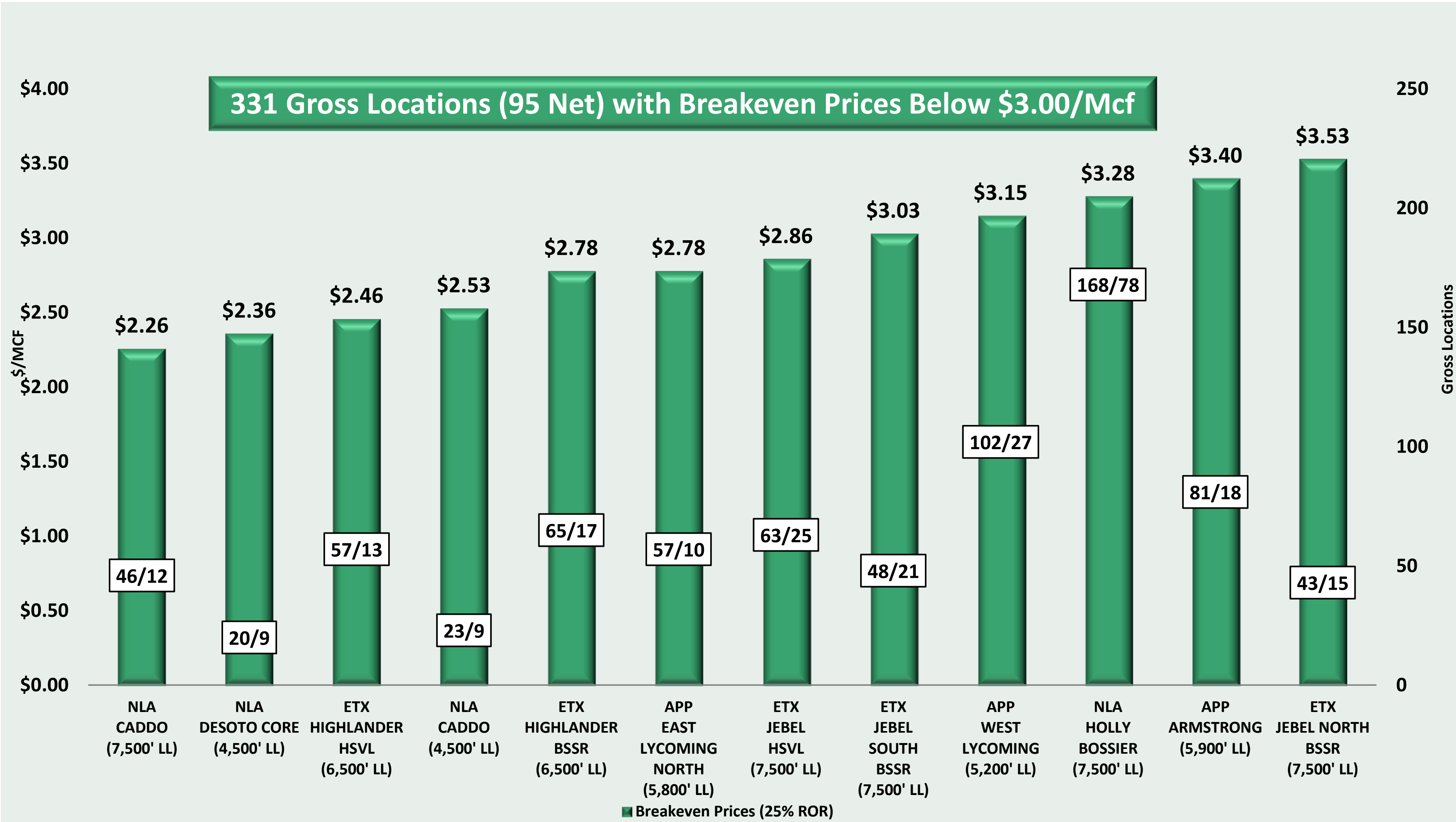


NLA and ETX wells continue to exceed expectations; pressure decline is currently <10 psi/day and volumes continue to exceed type curve expectations

High Quality Drilling Inventory

Drilling Inventory[1]
Breakeven Price Required for 25% IRR ($/Mcf)[2]; Gross/Net Locations

1



EXCO has more than 19 years of economic drilling locations with a 4 rig program drilling 41 wells per year

1. Excludes South Texas locations
2. Breakeven figures are wellhead returns

Financial and Operational Results

		Quarter-to-Date					Year-to-Date		
		1Q 17	4Q 16		1Q 16		1Q 17	1Q 16	
Factors	Unit	Actual	Actual	% Change	Actual	% Change	Actual	Actual	% Change
Rig Count	#	1	0	100	2	(50)	1	2	(50)
Gross/Net Wells Drilled	#	4/3.5	0/0.0	100[1]	5/4.3	(19)[1]	4/3.5	5/4.3	(19)[1]
Gross/Net Wells Turned to Sales	#	0/0.0	1/0.4	(100)[1]	8/3.6	(100)[1]	0/0.0	8/3.6	(100)[1]
Production									
Oil	Mbbl	331	381	(13)	550	(40)	331	550	(40)
Natural Gas	Bcf	19.7	21.9	(10)	23.5	(16)	19.7	23.5	(16)
Total	Bcfe	21.7	24.2	(10)	26.8	(19)	21.7	26.8	(19)
Total Daily	Mmcfe/d	241	263	(8)	295	(18)	241	295	(18)
Realized Price Differentials									
Oil	$/Bbl	(2.91)	(2.86)	2	(5.23)	(44)	(2.91)	(5.23)	(44)
Natural Gas	$/Mcf	(0.63)	(0.50)	26	(0.55)	15	(0.63)	(0.55)	15
Financial Results									
Lease Operating Expense	$/Mcfe	0.39	0.36	8	0.35	11	0.39	0.35	11
Production Taxes	$/Mcfe	0.16	0.09	78	0.17	(6)	0.16	0.17	(6)
Gathering and Transportation	$/Mcfe	1.26	1.10	15	0.94	34	1.26	0.94	34
Adj. General and Administrative[2]	$MM	6	6	2	9	(30)	6	9	(30)
Interest Expense[3]	$MM	15	16	(6)	17	(12)	15	17	(12)
Adj. EBITDA[4]	$MM	18	26	(31)	21	(14)	18	21	(14)
Capital Expenditures	$MM	18	8	125	37	(51)	18	37	(51)

1. Percentage change calculated using net wells drilled and net wells turned to sales
2. Adjusted General and Administrative is a non-GAAP measure. See appendix for definition and reconciliation
3. Cash interest expenses exclude interest paid or accrued in-kind, the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the second lien term loan ("Exchange Term Loan") and a portion of the 1.75 Lien Term Loans are not considered interest expense per FASB ASC 470-60, Troubled Debt Restructuring by Debtors ("ASC 470-60") and are excluded from the cash interest expenses amounts shown
4. Adjusted EBITDA is a non-GAAP measure. See appendix for definition and reconciliation

Actuals to Guidance Comparison

		Three Months Ended				
		1Q 17	1Q 17 Guidance		2Q 17 Guidance[3]	
Factors	Unit	Actual	Low	High	Low	High
Wells Spud (Gross/Net)	#	4/3.5	5/3.9		11/3.9	
Wells Turned to Sales (Gross/Net)	#	0/0.0	0/0.0		4/3.5	
Production						
Oil	Mbbl	331	300	320	200	220
Natural Gas	Bcf	19.7	19.4	20.1	18.4	19.2
Total	Bcfe	21.7	21.2	22.1	19.6	20.5
Total Daily	Mmcfe/d	241	235	245	215	225
Realized Price Differentials						
Oil	$/Bbl	(2.91)	(3.00)	(4.00)	(3.00)	(4.00)
Natural Gas	$/Mcf	(0.63)	(0.50)	(0.60)	(0.50)	(0.60)
Financial Results						
Lease Operating Expense	$/Mcfe	0.39	0.40	0.45	0.35	0.40
Production Taxes	$/Mcfe	0.16	0.15	0.20	0.15	0.20
Gathering and Transportation	$/Mcfe	1.26	1.20	1.25	1.25	1.30
General and Administrative[1]	$MM	6	9	10	6	7
Interest Expense[2]	$MM	15	24	28	12	16

1. Excludes equity based compensation
2. Interest expenses exclude interest paid or accrued in-kind, the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the second lien term loan ("Exchange Term Loan") and a portion of the 1.75 Lien Term Loans are not considered interest expense per FASB ASC 470-60, *Troubled Debt Restructuring by Debtors* ("ASC 470-60") and are excluded from the cash interest expenses amounts shown
3. Pro forma for STX divestiture

Appendix

Hedge Positions

Factors	Unit	Nine Months Ended 12/31/17		Twelve Months Ended 12/31/18	
		Volume	Price	Volume	Price
Natural Gas					
Fixed Price Swaps - Henry Hub	Bbtu, $/Mmbtu	27,500	3.05	3,650	3.15
Collars - Henry Hub	Bbtu	8,250			
Sold Call Options	$/Mmbtu		3.28		
Purchased Put Options	$/Mmbtu		2.87		
Oil					
Fixed Price Swaps - WTI	Mbbl, $/Bbl	137	50.00	-	-
Percent Hedged[1]					
Natural Gas	%	74		8	
Oil	%	16		-	

1. Percent hedged based on PDP production forecast

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 Highlander HSVL	ETX Highlander BSSR
1	Target Lateral Length	Ft	4,500	7,500	4,500	7,500	7,500	6,500	6,500
2	Gross Locations	#	20	46	23	168	63	57	65
3	Net Locations	#	9	12	9	78	25	13	17
4	WI	%	43	25	37	46	39	23	26
5	NRI	%	33	19	28	36	31	18	20
6	Spacing	Acres	136	227	136	227	241	221	223
	Type Curve								
7	IP	Mcf/d	14,000	17,600	13,200	10,900	9,300	11,500	9,500
8	Phase I – Duration Month	Month	16	16	16	12	12	18	16
9	Phase I – B Factor	x	0	0	0	0	0	0	0
10	Phase I – Initial Decline	%	50	40	52	41	22	22	22
11	Phase II – Duration Month	Month	10	10	10	14	15	54	56
12	Phase II – B Factor	x	0.6	0.6	0.6	0.6	0.6	0.6	0.6
13	Phase II – Initial Decline	%	51	52	51	37	42	42	41
14	Phase III – Duration Month	Month	16	16	16	16	9	24	24
15	Phase III – B Factor	x	1	1	1	1	1	1	1
16	Phase III – Initial Decline	%	42	42	42	37	39	25	25
17	Phase IV – Initial Decline	%	32	32	32	26	36	22	22
18	Terminal Decline	%	6	6	6	6	6	6	6
19	Wellhead EUR	Bcf	9.9	14.9	8.9	12	11.3	14.1	11.7
20	EUR per 1,000’ (lateral length)	Bcf	2.2	1.98	1.98	1.6	1.5	2.2	1.8
21	D&C	$MM	6.9	9.5	6.9	11.4	9.5	10.0	9.6
22	LOE Fixed	$/month	1,770	1,770	1,770	1,770	3,034	2,690	2,690
23	Variable/Gathering Expense	$/mcf	.05/.47	.05/.47	.05/.47	.06/.47	0.08/0.29	0.06/0.31	0.06/0.31
	Single Well Returns								
24	Breakeven Flat Price (25%)	$/MMBTU	2.36	2.26	2.53	3.28	2.86	2.46	2.78
25	PV/I, Disc[1]	x	1.82	1.95	1.64	1.19	1.40	1.72	1.46

1. Economics based on NYMEX futures prices as of March 31, 2017, including natural gas prices per MMBtu of $3.31 for 2017, $3.04 for 2018, $2.83 for 2019, $2.82 for 2020, $2.83 for 2021, $2.84 for 2022, $2.88 for 2023, $2.94 for 2024 and $3.00 thereafter

Non-GAAP Measures and Reconciliations

Consolidated EBITDA and Adjusted EBITDA Reconciliations

(in thousands)	Three Months Ended March 31, 2017	Three Months Ended December 31, 2016	Three Months Ended March 31, 2016
Net income (loss)	$ 8,193	$ (34,699)	$ (130,148)
Interest expense	19,952	16,252	19,257
Income tax expense	1,028	1,027	—
Depletion, depreciation and amortization	11,508	11,987	29,001
EBITDA (1)	$ 40,681	$ (5,433)	$ (81,890)
Accretion of discount on asset retirement obligations	212	204	912
Impairment of oil and natural gas properties	—	—	134,599
Other items impacting comparability	—	—	402
(Gain) loss on restructuring and extinguishment of debt	6,272	(83)	(45,114)
Equity (income) loss	(317)	7,608	7,910
Gain (loss) on derivative financial instruments - commodity derivatives	(15,533)	22,505	(16,591)
Cash receipts (payments) of commodity derivative financial instruments	(4,459)	1,052	16,790
Gain on derivative financial instruments - common share warrants	(6,004)	—	—
Equity-based compensation	(2,382)	220	3,813
Adjusted EBITDA (1)	$ 18,470	$ 26,073	$ 20,831
Interest expense	(19,952)	(16,252)	(19,257)
Current income tax expense	—	—	—
Amortization of deferred financing costs and discount	4,402	2,006	3,121
Other operating items impacting comparability and non-operating items	(21)	5	(422)
Changes in working capital	2,297	(8,506)	23,708
Net cash provided by operating activities	$ 5,196	$ 3,326	$ 27,981

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 and other operating items impacting comparability.

   EXCO has presented EBITDA and Adjusted EBITDA because they are a widely used measure 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 1.5 Lien Notes, the indenture governing the 2018 Notes, the indenture governing the 2022 Notes and the term loan credit agreement governing the 1.75 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 indentures and the term loan credit agreements.

Adjusted General and Administrative Expenses Reconciliations

(in thousands)	Three Months Ended March 31, 2017	Three Months Ended December 31, 2016	Three Months Ended March 31, 2016
General and administrative, GAAP	$ 4,415	$ 10,074	$ 10,897
Less: Equity-based compensation	2,382	(220)	(3,813)
Less: Restructuring and severance costs	(775)	(3,936)	1,489
Adjusted general and administrative, non-GAAP measure (1)	6,022	5,918	8,573

1. The Company believes this non-GAAP measure is used by investors, analysts and management for valuations, peer comparisons and other recommendations. The exclusion of equity-based compensation is important to users that are evaluating the impact of the Company's cash-based general and administrative costs on its credit metrics and ability to service its indebtedness. In addition, the exclusion of cash-based costs, such as restructuring and severance, assists in the comparability between periods and similar measures are used in debt covenant calculations required under certain of the Company's debt agreements. Restructuring costs include legal and advisory costs incurred in connection with the Company's strategic initiatives focused on restructuring its balance sheet and gathering and transportation contracts, and severance costs relate primarily to the Company's reductions in workforce.

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 limitations on our ability to incur certain types of indebtedness under our debt agreements and to refinance or replace existing debt obligations as they mature;
- 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;
- outcome of divestitures of non-core assets, including the potential sale of our assets in the South Texas region;
- cash flow and liquidity;
- our ability to enter into transactions as a result of our credit rating, including commodity derivatives with financial institutions and services with vendors;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of water, sand 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 commodity derivative financial instruments;
- decisions whether or not to enter into commodity 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;
- our ability to execute our business strategies and other corporate actions;
- outcome of shareholder approvals related to the warrants and issuance of common shares in connection with the 1.5 Lien Notes and 1.75 Lien Term Loans;
- decisions to pay interest on the 1.5 Lien Notes and 1.75 Lien Term Loans in cash, common shares or additional indebtedness; and
- our ability to continue as a going concern

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 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, 2016, filed with the Securities and Exchange Commission ("SEC") on March 16, 2017 and its other periodic filings with the SEC.

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. Revenues, operating results and financial condition substantially depend on prevailing prices for oil and natural gas and the availability of capital from our credit agreement. 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. EXCO undertakes no obligation to publicly update or revise any forward-looking statements.