Gulfport ENERGY

Investor Presentation

March 2017

Forward Looking Statement

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Gulfport expects or anticipates will or may occur in the future, including but not limited to the acquisition from Vitruvian, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of Gulfport's business and operations, plans, market conditions, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by Gulfport in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with Gulfport's expectations and predictions is subject to a number of risks and uncertainties, general economic, market, credit or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by Gulfport; Gulfport's ability to identify, complete and integrate acquisitions of properties and businesses; competitive actions by other oil and gas companies; changes in laws or regulations; and other factors, many of which are beyond the control of Gulfport. Information concerning these and other factors can be found in the Company's filings with the Securities and Exchange Commission, including its Forms 10-K, 10-Q and 8-K. Consequently, all of the forward-looking statements made in this news release are qualified by these cautionary statements and there can be no assurances that the actual results or developments anticipated by Gulfport will be realized, or even if realized, that they will have the expected consequences to or effects on Gulfport, its business or operations. Gulfport has no intention, and disclaims any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Gulfport's estimated proved reserves as of December 31, 2016 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to Gulfport's assets in the Utica Shale of Eastern Ohio and Gulfport's WCBB and Hackberry fields and by Gulfport's personnel with respect to its Niobrara field, overriding royalty and non-operated interests (less than 1% of its proved reserves at December 31, 2016), and comply with definitions promulgated by the SEC. NSAI is an independent petroleum engineering firm. In this presentation, we may use the terms "EUR," or other descriptions of volumes of hydrocarbons to describe volumes of resources potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines prohibit it from including in filings with the SEC. "EUR" does not reflect volumes that are demonstrated as being commercially or technically recoverable. Even if commercially or technically recoverable, a significant recovery factor would be applied to these volumes to determine estimates of volumes of proved reserves. Accordingly, these estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the Company. The methodology for "EUR" may also be different than the methodology and guidelines used by the Society of Petroleum Engineers and is different from the SEC's guidelines for estimating probable and possible reserves.

EBITDA is a non-GAAP financial measure equal to net (loss) income, the most directly comparable GAAP financial measure, plus interest expense, income tax (benefit) expense, accretion expense, depreciation, depletion and amortization and impairment of oil and gas properties. Adjusted EBITDA is a non-GAAP financial measure equal to EBITDA less non-cash derivative loss, gain from insurance proceeds, loss from impairment of Grizzly equity investment, loss on debt extinguishment and loss from equity method investments. Cash flow from operating activities before changes in operating assets and liabilities is a non-GAAP financial measure equal to cash provided by operating activity before changes in operating assets and liabilities. Adjusted net income is a non-GAAP financial measure equal to pre-tax net loss less non-cash derivative loss, loss from impairment of oil and gas properties, gain from insurance proceeds, impairment of Grizzly equity investment, loss on debt extinguishment and loss from equity method investments. The Company has presented EBITDA and adjusted EBITDA because it uses these measures as an integral part of its internal reporting to evaluate its performance and the performance of its senior management. These measures are considered important indicators of the operational strength of the Company's business and eliminate the uneven effect of considerable amounts of non-cash depletion, depreciation of tangible assets and amortization of certain intangible assets. A limitation of these measures, however, is that they do not reflect the periodic costs of certain capitalized tangible and intangible assets used in generating revenues in the Company's business. Management evaluates the costs of such tangible and intangible assets and the impact of related impairments through other financial measures, such as capital expenditures, investment spending and return on capital. Therefore, the Company believes that these measures provide useful information to its investors regarding its performance and overall results of operations. EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities are not intended to be performance measures that should be regarded as an alternative to, or more meaningful than, either net income as an indicator of operating performance or to cash flows from operating activities as a measure of liquidity. In addition, EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities are not intended to represent funds available for dividends, reinvestment or other discretionary uses, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. The EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities presented in this press release may not be comparable to similarly titled measures presented by other companies, and may not be identical to corresponding measures used in the Company's various agreements.

Gulfport Company Overview

Primary Areas of Operation (4)

Utica Shale
Acreage: ~213,000 Net Acres

SCOOP
Acreage: ~85,000 Net Effective Acres

Key Statistics

Market Capitalization[1]	**$2.9 Billion**
Enterprise Value[2]	**$4.4 Billion**
Pro Forma Liquidity[3]	**~$873 Million**
2016 Average Daily Production	**719.8 Mmcfepd**
1Q16	692.2 Mmcfepd
2Q16	664.7 Mmcfepd
3Q16	734.1 Mmcfepd
4Q16	787.0 Mmcfepd
2017E Average Daily Production	**1,045 – 1,100 Mmcfepd**
Net Core Acreage[4]	
Utica Shale	~213,000 acres
SCOOP	~85,000 acres
Identified Gross Locations	
Utica Shale[5]	~1,270 gross locations
SCOOP	~1,750 gross locations

1) Market capitalization calculated as of the close of the market on 3/23/17 at a price of $15.89 per share using shares outstanding from the Company's 4Q2016 financial statements and pro forma for the issuance of common stock to Vitruvian in acquisition.
2) Enterprise value calculated as of the close of the market on 3/23/17 at a price of $15.89 per share using shares outstanding, short-term debt, long-term debt, and cash and cash equivalents from the Company's 4Q2016 financial statements and pro forma for the issuance of common stock to Vitruvian in acquisition.
3) Pro Forma liquidity calculated as of 12/31/16 using borrowing base availability, letters of credit outstanding and cash and cash equivalents from the Company's 4Q2016 financial statements and pro forma for the incremental estimated Vitruvian borrowing base increase.
4) Utica Shale acreage as of 2/13/17; SCOOP acreage includes ~46,400 Woodford and ~38,600 Springer effective net acres.
5) Assumes net undeveloped locations grossed up from 75% working interest.

Overview of Gulfport

- **Gulfport Energy Corporation ("GPOR") is an independent E&P company based in Oklahoma City, OK**
  - Company born from legacy assets in South Louisiana
  - Free cash flow from legacy assets facilitated expansion into North America's premier resource plays

1997 – 1998	1998 – 2005	2005 – 2007	2007 – 2012	2012 – Today
Phase 1: Formation / Asset Focus	**Phase 2: Low Risk Development**	**Phase 3: Resource Diversification**	**Phase 4: Resource Play Addition**	**Phase 5: Resource Development and Expansion**
• Gulfport Energy was formed in July 1997 • Initial assets were those of WRT Energy and a 50% working interest in the West Cote Blanche Bay ("WCBB") field contributed by DLB Oil and Gas • Gulfport divested a number of assets during this period leaving a cleaner balance sheet and focused asset base	• Focused on production and cash flow growth from low risk development activities principally in WCBB • Reprocessed 3D seismic in WCBB field • Created a track record of successful drilling	• Continued successful drilling and growth at the WCBB field • Conducted a 3-D seismic shoot and drilled first exploratory wells in Hackberry field • Amassed solid acreage position in Canadian Oil Sands and launched core hole drilling program • Acquired interest in Phu Horm natural gas field in Thailand	• Acquired initial acreage position in Permian Basin and expanded through acquisitions • Acquired larger interest in second natural gas field in Thailand • Secured sizable position in the core of the Utica Shale achieving early entrant advantages • Began vertical integration efforts in the Utica Shale to secure access to quality services	• Initiated drilling program to begin developing Utica Shale resource and currently running a six rig drilling program • Contributed Permian Basin interests in Diamondback Energy, Inc. IPO • Contributed certain services investments into Mammoth Energy Services, Inc. IPO • Acquired assets in the core of the SCOOP play and currently running a four rig drilling program

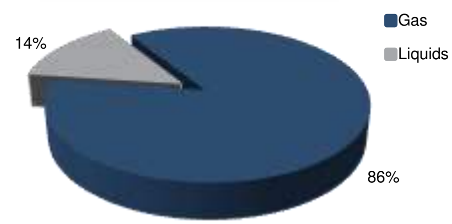
Fourth Quarter and Year-End 2016 Results

Daily Net Production

Increased 31% Year-over-Year

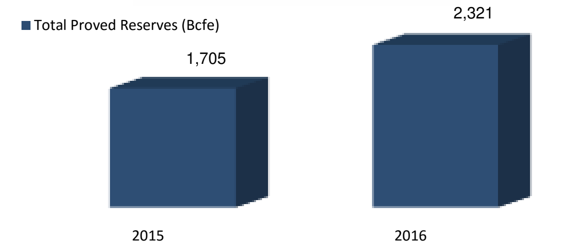
Produced ~719.8 MMcfe per day during 2016

Production Mix



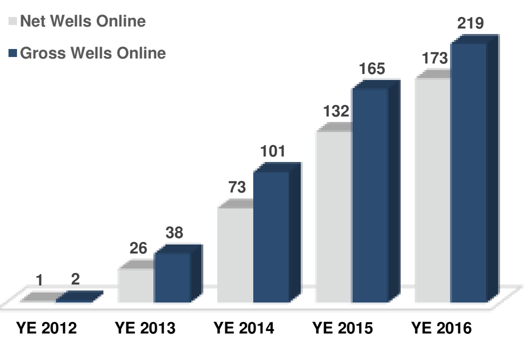
Production mix consisted of 86% gas and 14% liquids during 2016

Proved Reserves



Proved reserves of 2.3 Tcfe at year-end 2016, an increase of 36% Year-over-Year

Cumulative Utica Wells Online



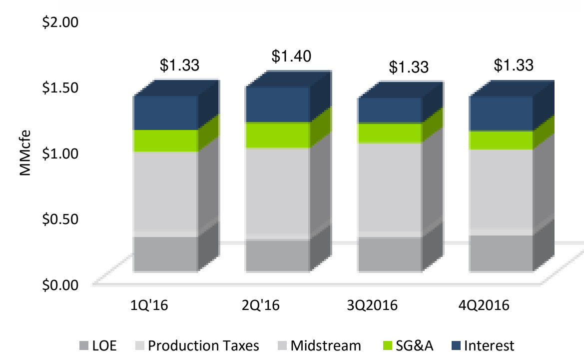
At year-end 2016, 219 gross (173 net) Operated Utica wells producing

Adjusted Oil and Gas Revenues

Increased 13% Year-over-Year

Totaled Approximately $709.2 million[1] during 2016

Per Unit Levered Cash Costs



$1.33 per Mcfe in 4Q2016, a decrease of 9% Year-over-Year

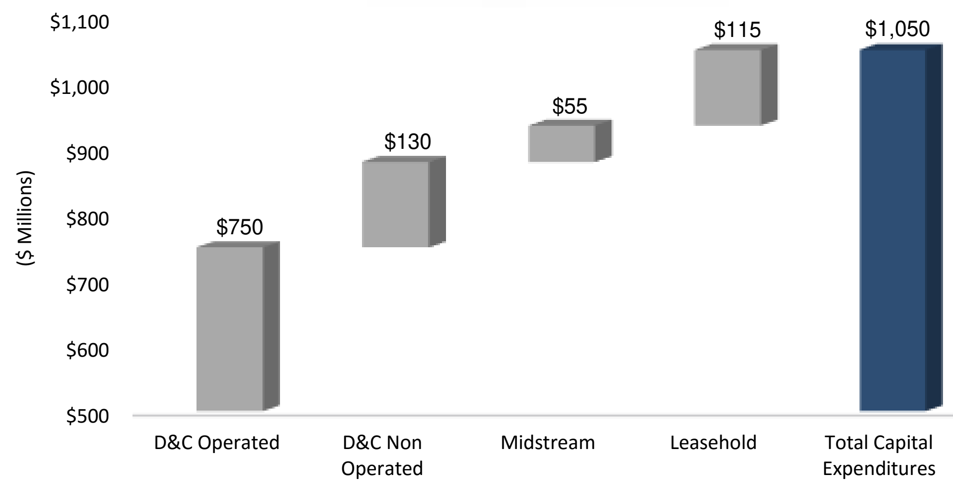
1) 2016 oil and gas revenues excluding the impact of non-cash derivative loss.

2017 Planned Activity

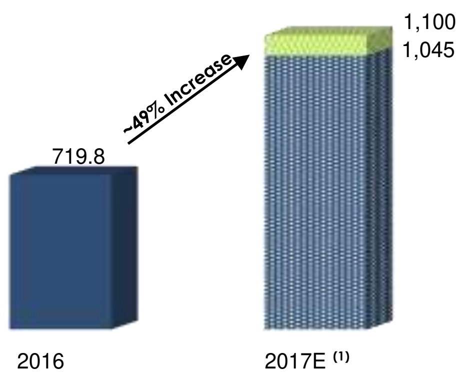
Key Highlights

- **Expect to invest $1.0 to $1.1 billion in 2017**
  - Plan to fund within available sources of liquidity
- **In the Utica Shale, currently running six drilling rigs**
  - Plan to drill 67 to 74 net operated wells and turn-to-sales 61 to 67 net operated wells during 2017
  - Will focus largely within the dry gas window during 2017
  - Reduced expected Utica well costs by ~$750K for 2017
- **In the SCOOP, plan to run four drilling rigs in 2017**
  - Plan to drill 16 to 18 net operated wells and turn-to-sales 14 to 16 net operated wells during 2017
  - Will focus within the wet gas gas window during 2017

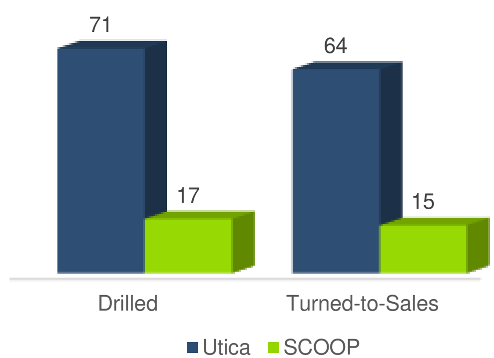
2017E Capital Expenditures[1]



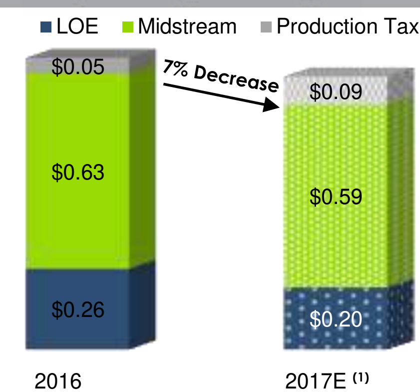
Daily Production (Mmcfepd)



2017E Operated Well Activity[1]



Operating Costs ($/Mcfe)

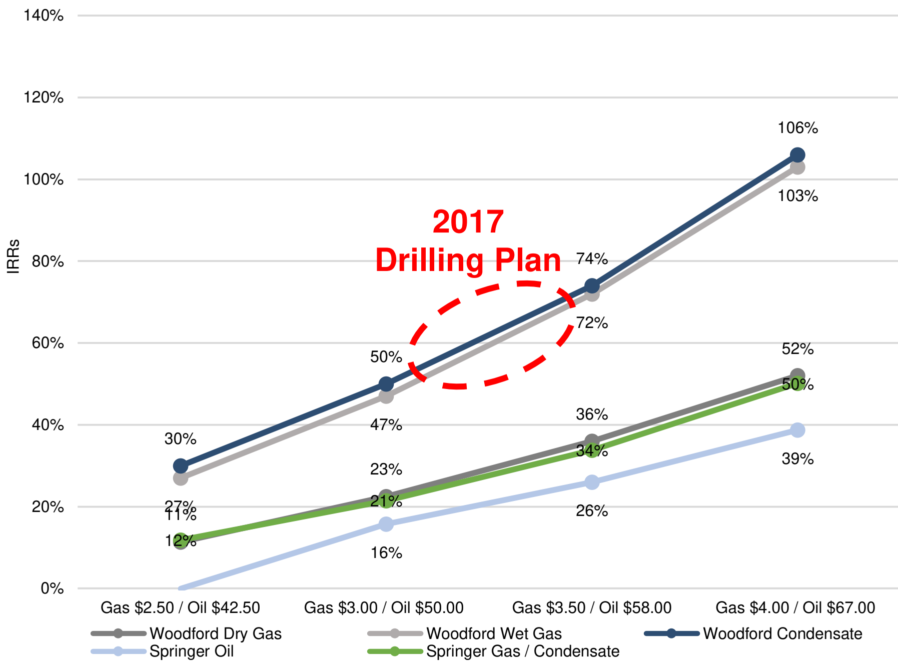


1) Based on the midpoint of 2017 guidance. Guidance for the year ending 12/31/17 is based on multiple assumptions and certain analyses made by the Company in light of its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward looking statements.

2017 Activity Economic Focus

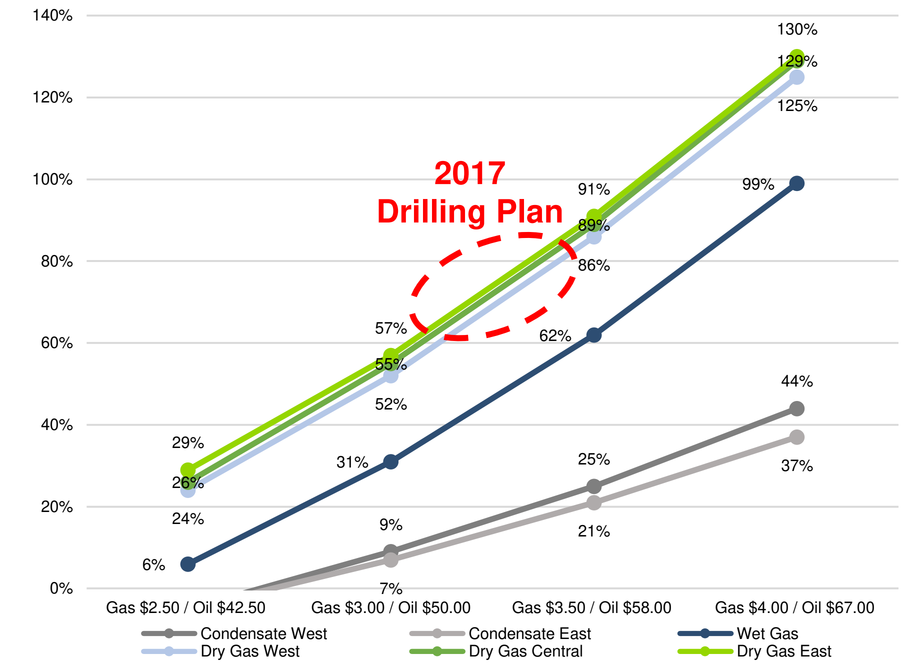
- **During 2017, plan to focus Utica Shale activity in the dry gas windows and SCOOP activity in the wet gas window of the play.**
- **Allocation of capital split between two top-tier basins with dry gas and liquids inventory.**

SCOOP Single Well Economics(1,2)



	Woodford Dry Gas	Woodford Wet Gas	Woodford Condensate	Springer Gas Condensate	Springer Oil
Gross Undeveloped Locations	402	528	249	215	354
Net Undeveloped Locations	65	182	33	72	70

Utica Single Well Economics(1,2)



	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Gross Undeveloped Locations(30	144	87	128	189	449	273
Net Undeveloped Locations	108	65	96	141	337	205

1) Assumes ethane rejection.
2) Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
3) Assumes net undeveloped locations grossed up from 75% working interest.

Gulfport 2017 Guidance

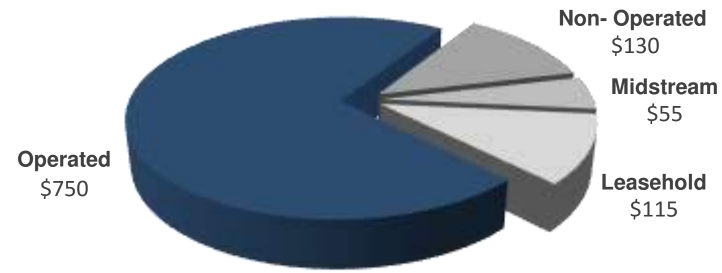
2017E Capital Budget

	Year Ending 12/31/2017	
Forecasted Production		
Average Daily Gas Equivalent – MMcfepd	1,045	1,100
% Gas	~88%	
% NGLs	~8%	
% Oil	~4%	
Forecasted Realizations (before the effects of hedges)[1]		
Natural Gas (Differential to NYMEX) - $ per Mcf	($0.56)	($0.62)
NGL (% of WTI)	~35%	
Oil (Differential to NYMEX WTI) - $ per Bbl	($4.50)	($5.50)
Projected Operating Costs		
Lease Operating Expense - $/Mcfe	$0.18	$0.23
Midstream Gathering and Processing - $/Mcfe	$0.55	$0.62
Production Taxes - $/Mcfe	$0.08	$0.09
General and Administrative[2] - $/Mcfe	$0.15	$0.17
Depreciation, Depletion, and Amortization - $/Mcfe	$0.95	$1.05
Budgeted D&C Capital Expenditures – in Millions:		
Operated	$720	$780
Non - Operated	$125	$135
Total Budgeted D&C Capital Expenditures	$845	$915
Budgeted Midstream Capital Expenditures – in Millions:	$50	$60
Budgeted Leasehold Capital Expenditures – in Millions:	$110	$120
Total Budgeted Capital Expenditures – in Millions:	$1,005	$1,095

2017E Forecasted Activity

	Year Ending 12/31/2017	
Net Wells Drilled		
Utica – Operated	67	74
Utica – Non – Operated	10	11
Total	77	85
SCOOP – Operated	16	18
SCOOP – Non - Operated	1	2
Total	17	19
Net Wells Turned-to-Sales		
Utica – Operated	61	67
Utica – Non - Operated	9	10
Total	70	77
SCOOP – Operated	14	16
SCOOP – Non - Operated	1	2
Total	15	18

2017E CAPEX (in millions)[3]

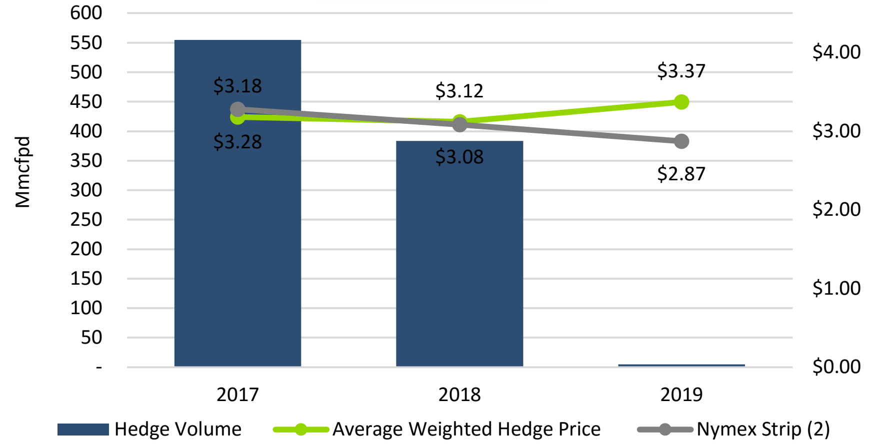


1) Based upon current forward pricing and basis marks.
2) Includes non-cash stock compensation.
3) Based on midpoint of 2017 guidance.

Note: Guidance for the year ending 12/31/17 is based on multiple assumptions and certain analyses made by the Company in light of its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward looking statements.

Strong Post Acquisition Liquidity, Capitalization and Hedge Position

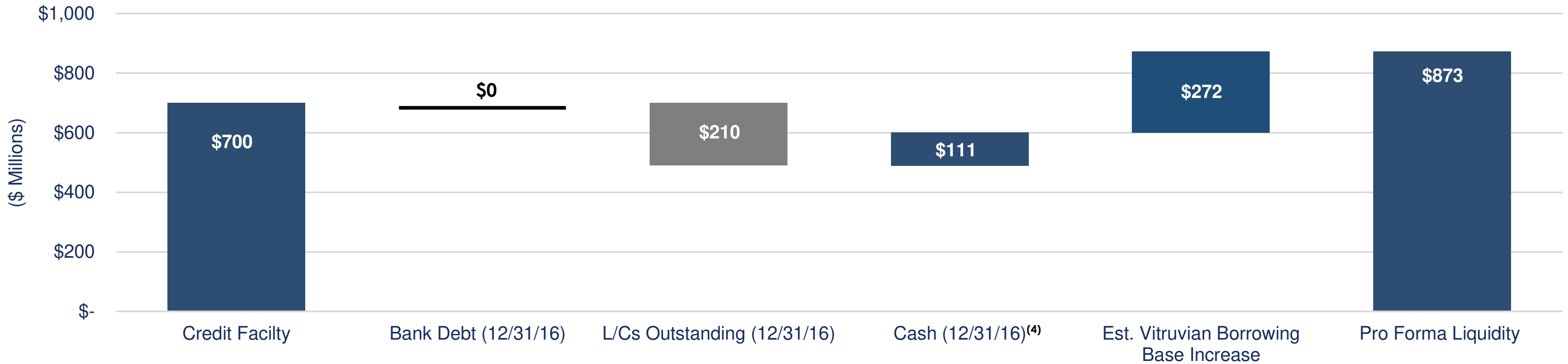
Gas Hedges(1)



Key Highlights

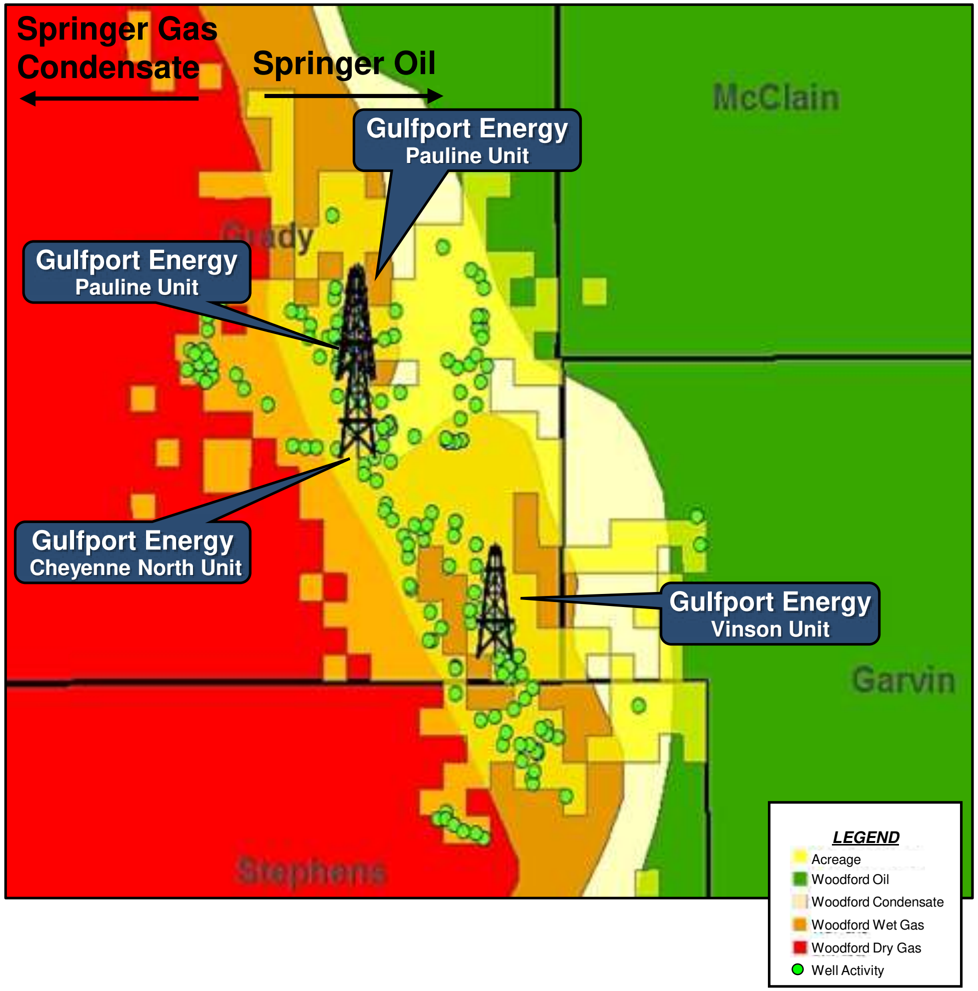
- **Gulfport's strategic commitment to the balance sheet and conservative leverage metrics provide the ability to pursue an aggressive growth plan in 2017**
- **Strong liquidity to fund 2017 capital programs with cash flow and available sources of liquidity**
  - Pro forma liquidity of $873 million(3)
- **Strong hedge position in 2017 and beyond**
  - Approximately 60% of expected 2017 natural gas production hedged at $3.18 per MMBtu
  - Large base of hedges for 2018 locked in at $3.12 per MMBtu

Pro Forma Liquidity Position(3)



1) Hedge volume and weighted average price excludes swaptions. Detailed overview in appendix of the presentation.
2) Price forecast as of 2/10/17.
3) Pro Forma liquidity calculated as of 12/31/16 using borrowing base availability, letters of credit outstanding and cash and cash equivalents from the Company's 4Q2016 financial statements and pro forma for incremental estimated Vitruvian borrowing base increase.
4) Cash pro forma for Vitruvian acquisition.

SCOOP Post-Closing Update

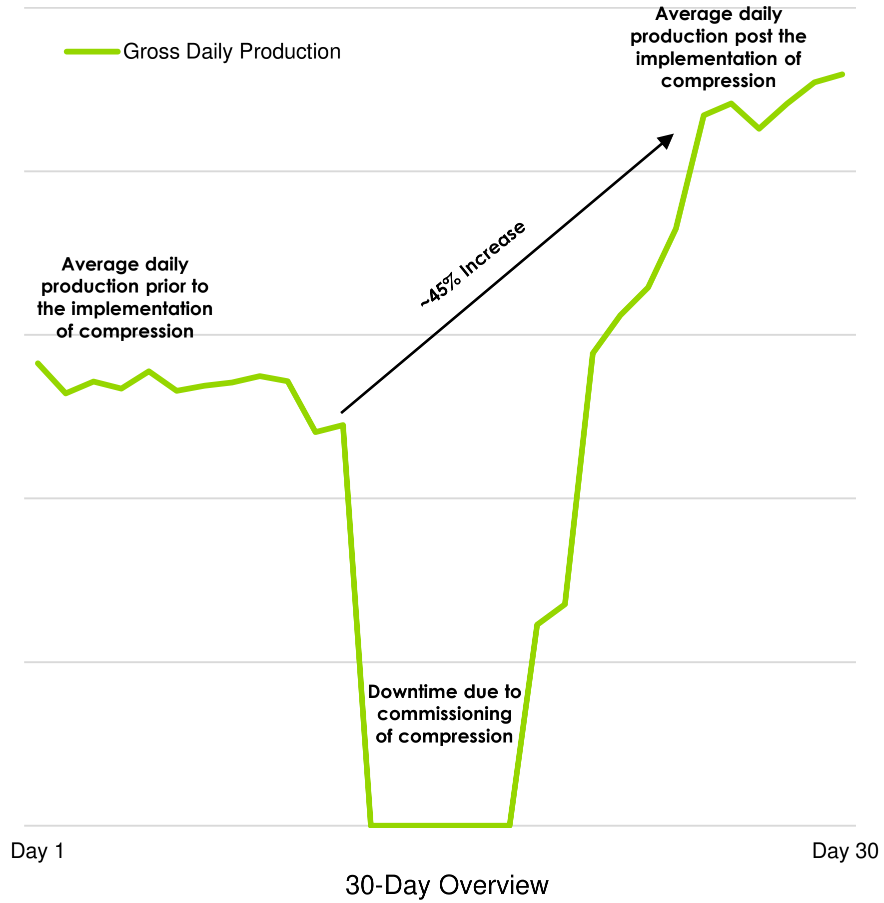


Overview

- **On February 17, 2017 Gulfport closed the previously announced acquisition of assets from Vitruvian II Woodford in the core of the SCOOP play**
- **Currently running 4 horizontal operated rigs in the play**
- **Began pumping first operated frac on March 1, 2017**
  - Frac design on these wells includes an enhanced completion when compared to historical practices for the area
    - Design consists of 180' stage lengths at ~2,250 to 2,400 pounds of proppant per foot of lateral
- **Recently executed firm transportation commitment with Midship Pipeline Company, a wholly owned subsidiary of Cheniere Energy, on the Midship Project**
  - Secured foundation shippers status with a commitment of at least ~175,000 MMBtu per day of takeaway
  - Targeted in-service date in early 2019
  - Provides delivery of molecules to Bennington and Perryville hubs

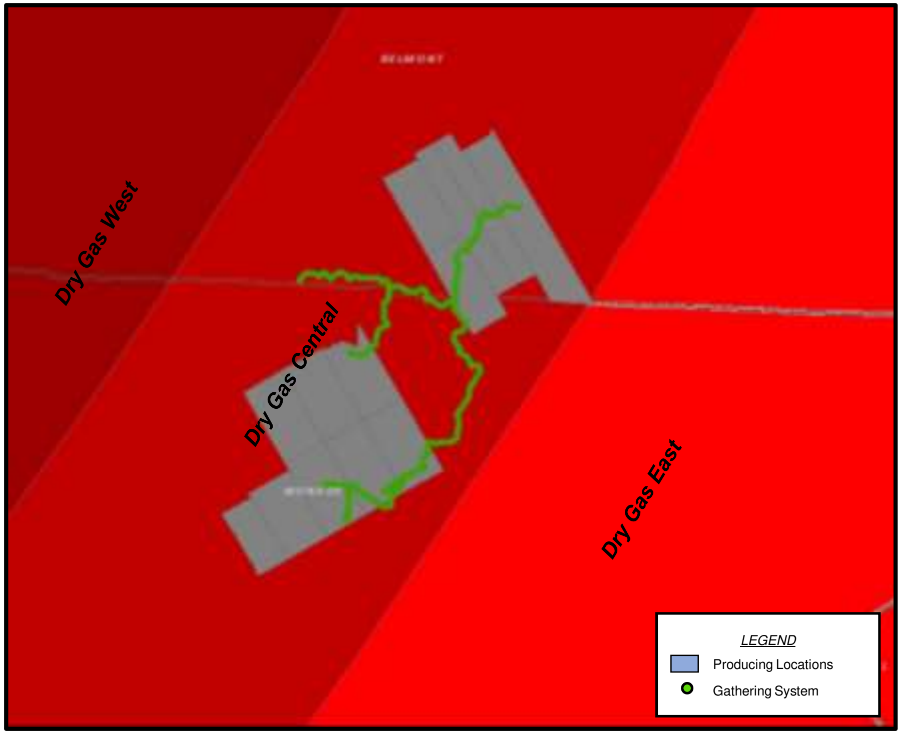
Utica Shale Compression Update

Affected Area Daily Gross Production



Overview

- **Commissioned field level compression in affected gathering area during the first quarter of 2017**
  - Implementation of compression resulted in an approximate 45% initial uplift to current production levels flowing through the affected gathering system



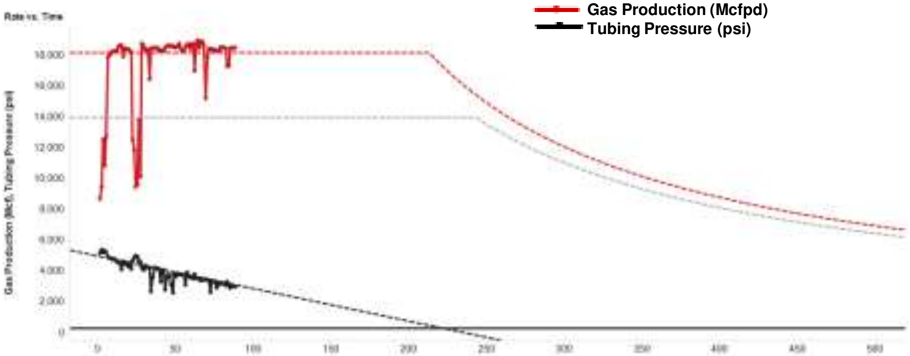
Utica Shale Dry Gas Performance

- **Recent fourth quarter 2016 and first quarter 2017 turn-in-lines continue to perform at or above expectations**
  - Sample set includes twelve wells from four separate pads

Dry Gas West 2 Well Pad[1]

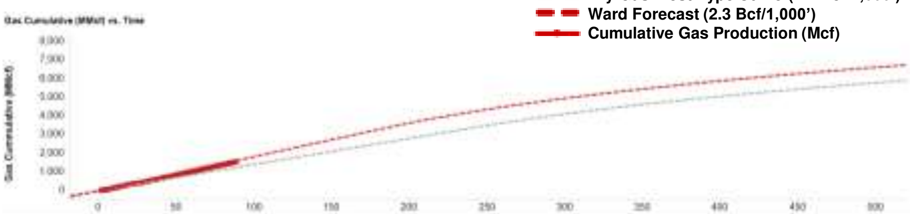
Daily Production

Dry Gas West Type Curve (2.2 Bcf/1,000')
Ward Forecast (2.3 Bcf/1,000')
Gas Production (Mcfpd)
Tubing Pressure (psi)



Cumulative Production

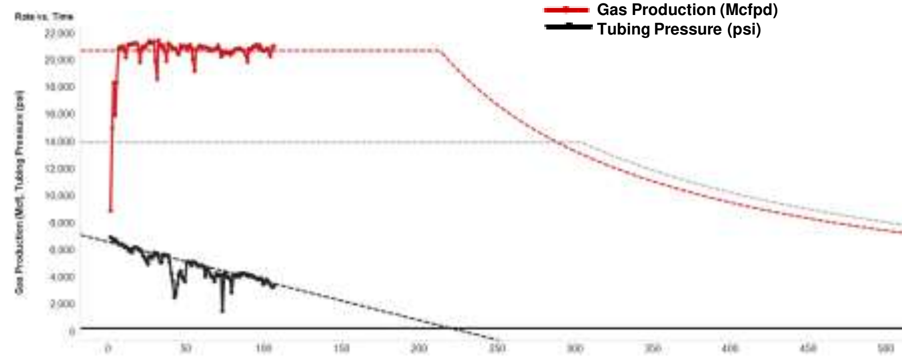
Dry Gas West Type Curve (2.2 Bcf/1,000')
Ward Forecast (2.3 Bcf/1,000')
Cumulative Gas Production (Mcf)



Dry Gas East 3 Well Pad [1]

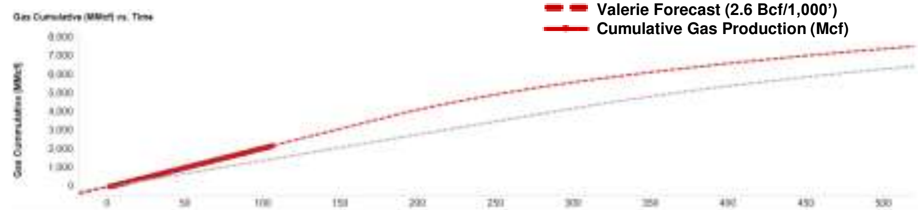
Daily Production

Dry Gas East Type Curve (2.6 Bcf/1,000')
Valerie Forecast (2.6 Bcf/1,000')
Gas Production (Mcfpd)
Tubing Pressure (psi)



Cumulative Production

Dry Gas East Type Curve (2.6 Bcf/1,000')
Valerie Forecast (2.6 Bcf/1,000')
Cumulative Gas Production (Mcf)



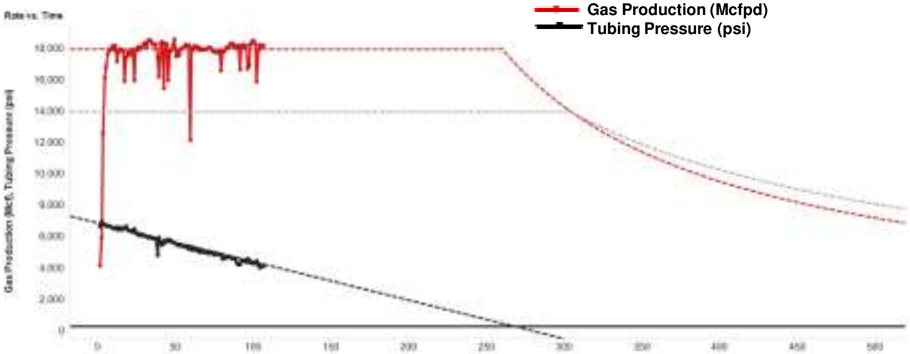
1) Production history normalized to 8,000' lateral.

Utica Shale Dry Gas Performance

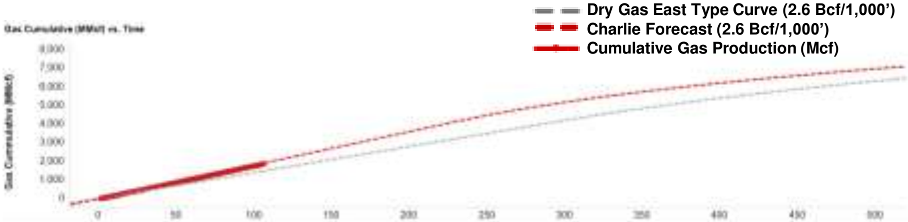
Dry Gas East 6 Well Pad[1]	Dry Gas East One Well Pad[1]

Dry Gas East 6 Well Pad[1]

Daily Production

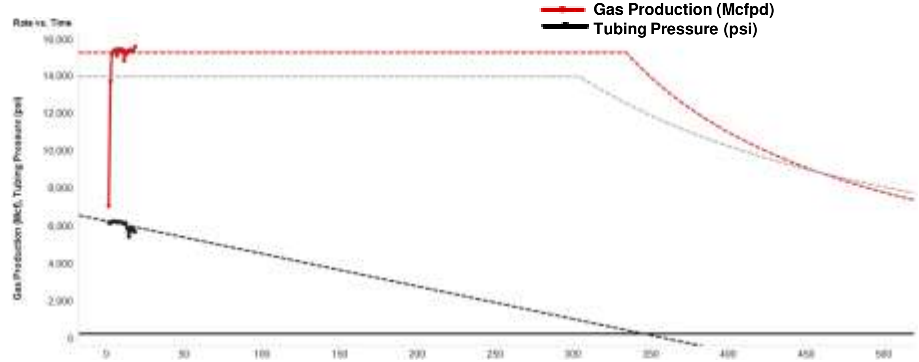


Cumulative Production

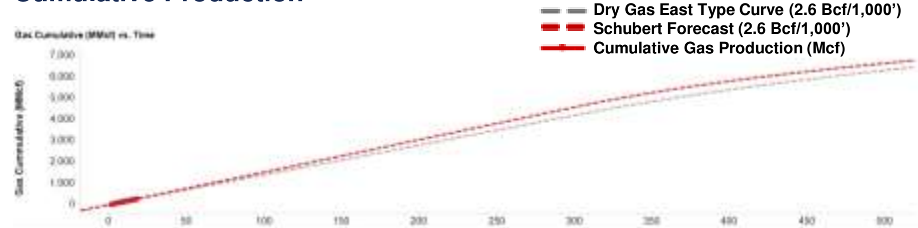


Dry Gas East One Well Pad[1]

Daily Production



Cumulative Production



1) Production history normalized to 8,000' lateral.

Key Investment and Financial Highlights

High Quality Assets

- **Core acreage positions in two of the most prolific, high-quality natural gas plays in North America**
  - Basin diversification provides optionality to allocate capital across two premier assets
  - Significant inventory in two lost cost basins with low well breakeven economics and IRRs in excess of 70%(1)
- **Significant exposure to the core of the Utica Shale with approximately ~213,000(2) net acres under lease**
  - Produced 768.0 MMcfepd during 4Q2016
  - Development expected to provide further catalyst for reserves and production growth
- **Low-risk, highly contiguous SCOOP acreage with approximately 85,000(2) net effective acres in the core of the play**
  - Stacked-pay zones provide significant upside
  - Liquids exposure in attractive market complements production base, enhances cash margins and provides drilling optionality from dry gas to liquids rich wet gas

Financial Philosophy and Hedge Position

- **Strong balance sheet and cash flow expected to allow Gulfport to continue to drive production growth**
  - Pro forma liquidity of approximately $873 million(3)
  - Expect to fund 2017 development plan within available sources of liquidity
- **Gulfport hedges a portion of its expected production to lock in prices and returns, providing certainty of cash flows to execute on its capital plans**
  - Currently ~60%(4) of 2017E natural gas production is hedged attractively at $3.18 per MMBtu
  - Company has historically targeted hedging 50% to 70% of expected twelve-month run rate total production

Well Positioned for 2017

- **Gulfport has adjusted activity in the near-term to take advantage of an improving natural gas market**
  - Increasing activity heading into 2017, with six rigs running in the Utica today and plans to run a four rig program in the SCOOP
  - Anticipated 2017 D&C capital budget of $845 to $945 million, yielding top-tier year-over-year growth of approximately 45% to 53%

1) Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
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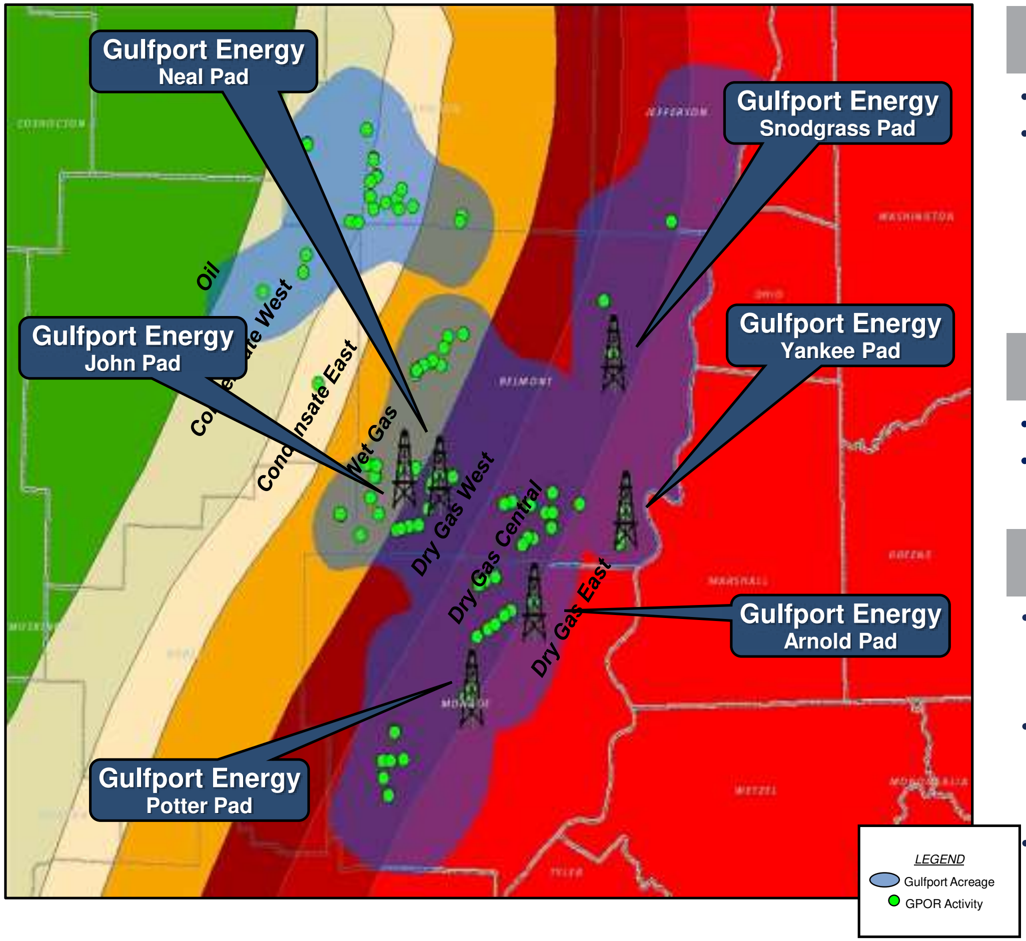
4) Based on the midpoint of 2017 guidance and excludes swaptions. Detailed overview in appendix of the presentation.

Utica Asset Overview

Utica Shale Overview



Asset Overview

- **Net proved reserves of 2.3 Tcfe[1]**
- **~213,000 net acres[2]**
  - Oil - ~ 1%
  - Condensate - ~12%
  - Wet Gas - ~ 13%
  - Dry Gas - ~ 74%

2016 Activities Update[3]

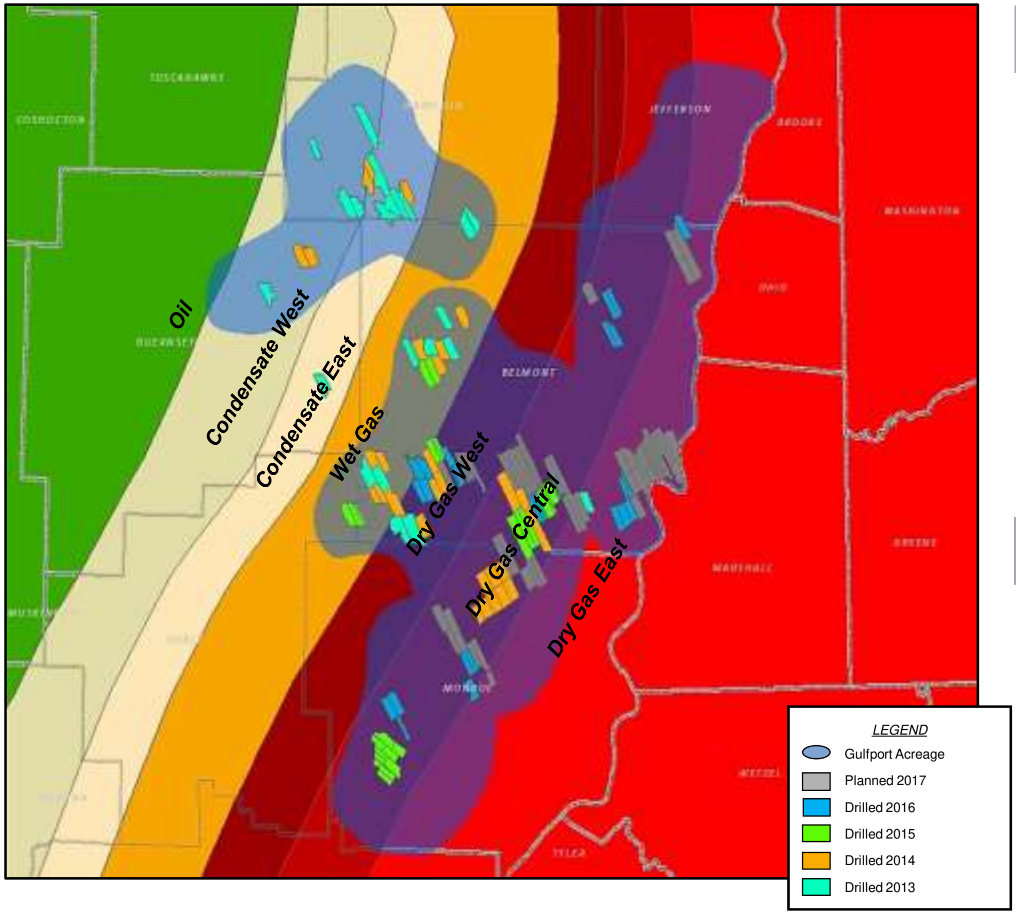
- **Average net production of 768.0 MMcfepd**
- **~98% of Gulfport's total net production**

2017 Planned Activities[4]

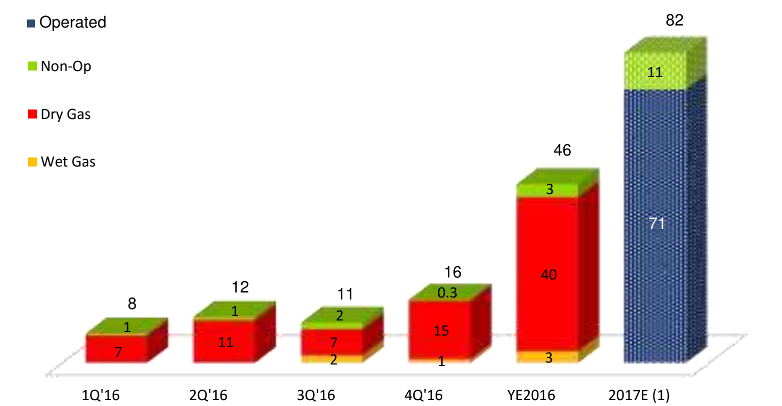
- **Currently running 6 gross operated rigs**
  - Plan to run ~6 operated rigs and participate in non-operated activity during 2017
- **Operated Activity**
  - Drill 87 to 97 gross (67 to 74 net) wells
  - Turn-to-sales 72 to 80 gross (61 to 67 net) wells
- **Non-Operated Activity**
  - Drill 30 to 34 gross (10 to 11 net) wells
  - Turn-to-sales 42 to 46 gross (9 to 10 net) wells

Note: Please refer to page 2 for detail on forward looking statements.
1) As of 12/31/16.
2) Acreage as of 2/13/17.
3) During the three months ended 12/31/16.
4) As of 2/13/17.

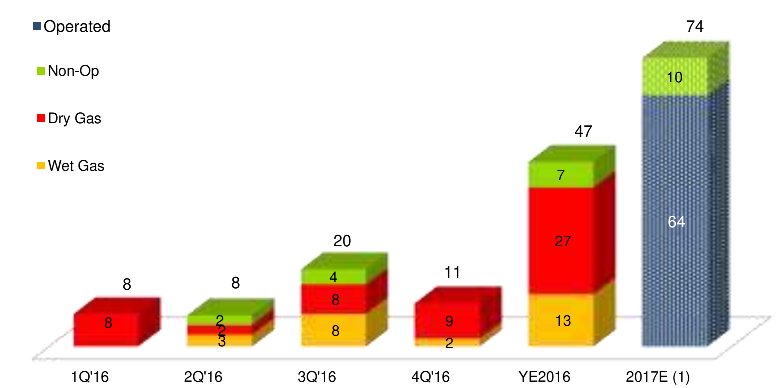
Utica Shale – Drilling and Completion Activity



Net Wells Drilled

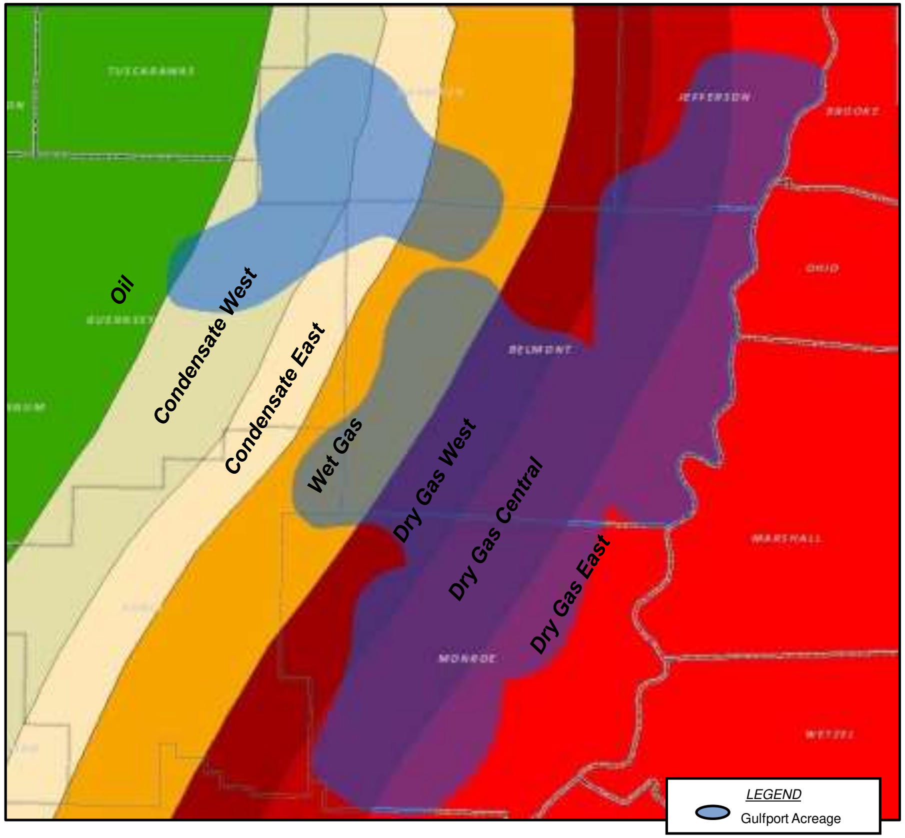


Net Wells Turned-to-Sales



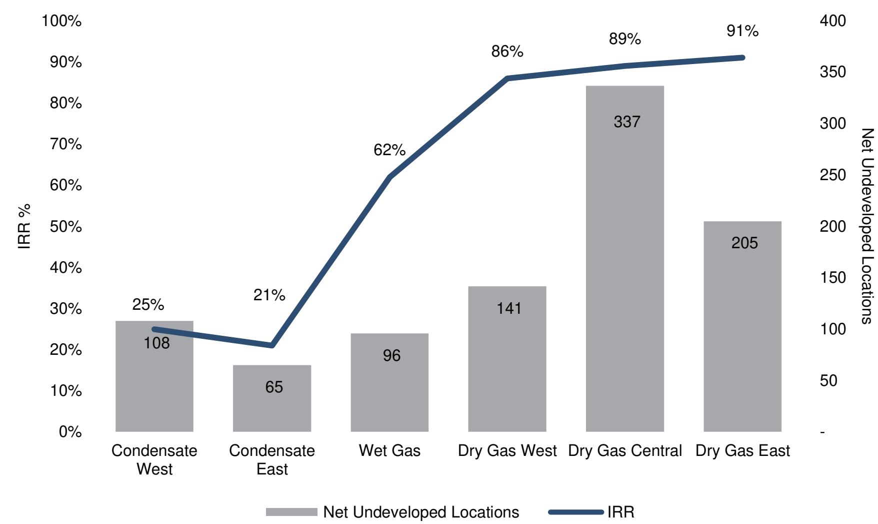
1) Based on midpoint of 2017 guidance.

Utica Shale – Type Curve Assumptions



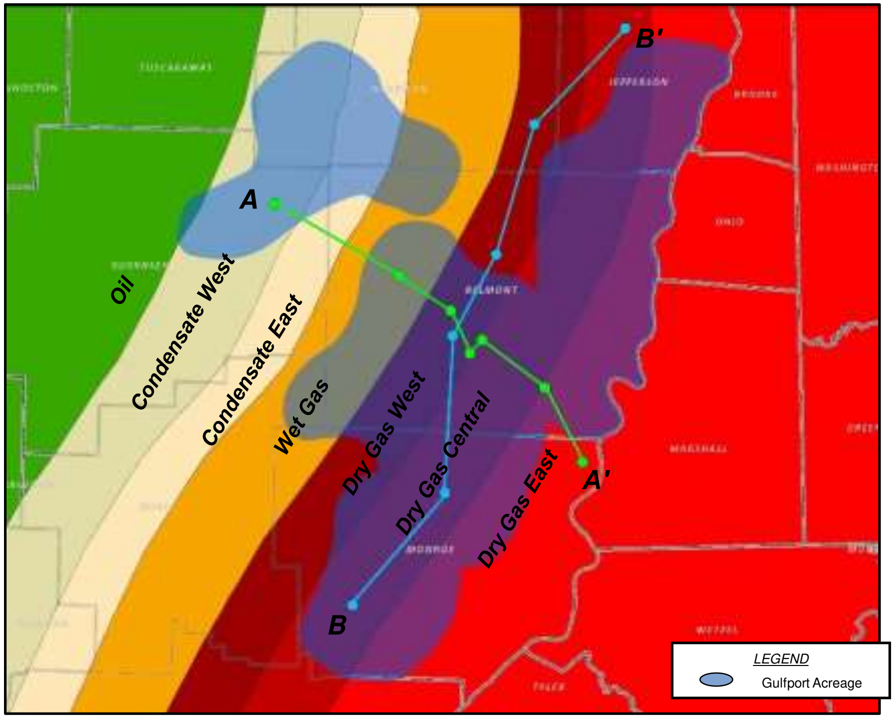
Type Curve Assumptions [1]	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Lateral Length	8,000	8,000	8,000	8,000	8,000	8,000
Well Cost ($MM)	$7.7	$7.7	$8.3	$8.5	$8.7	$8.9
Well Cost ($ per foot)	$962	$964	$1,035	$1,060	$1,085	$1,110
Total EUR (Bcfe / 1,000)	0.7	1.0	2.0	2.2	2.4	2.6
Total EUR (Bcfe)	5.7	8.1	16.0	17.2	19.0	20.7
% Gas	42%	56%	77%	100%	100%	100%
Assumed Well Spacing (ft)	600	600	1,000	1,000	1,000	1,000
Gross Undeveloped Locations[3]	144	87	128	189	449	273
Net Undeveloped Locations	108	65	96	141	337	205

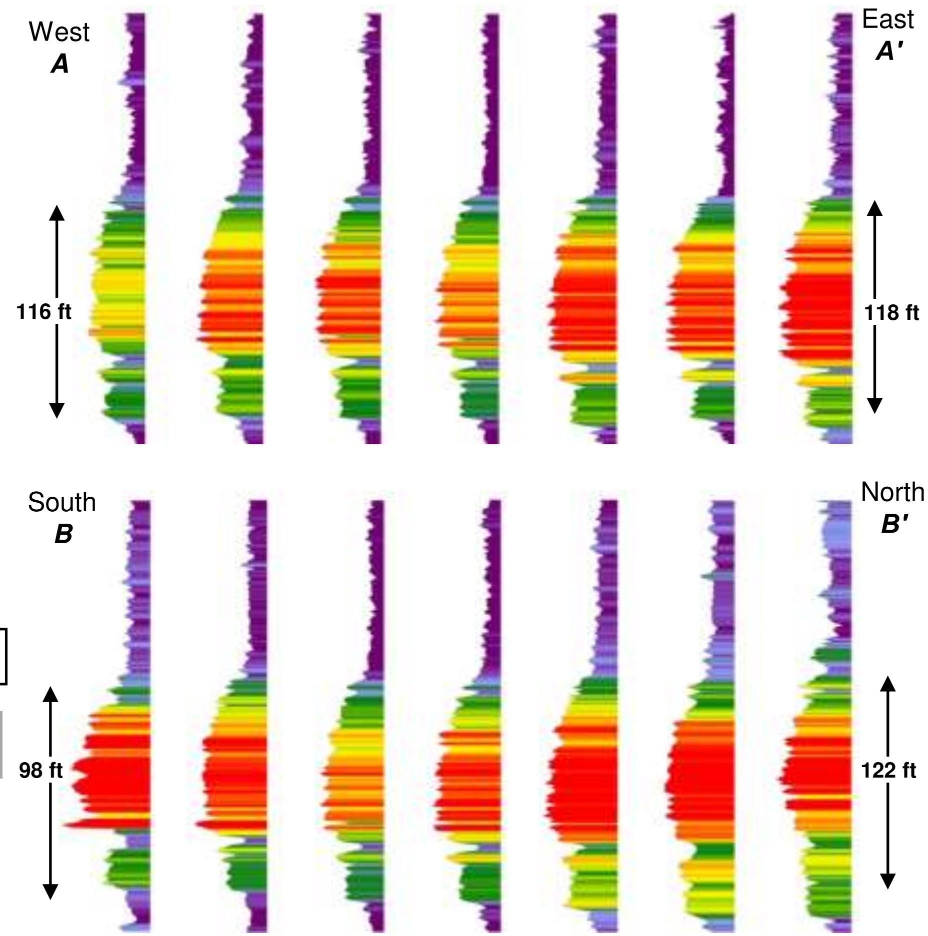
Utica Single Well Economics[1] [2]



Note: See appendix slide 39 for net undeveloped locations.
1) Assumes ethane rejection.
2) Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
3) Assumes net undeveloped locations grossed up from 75% working interest.

Utica Shale – Consistency of Reservoir



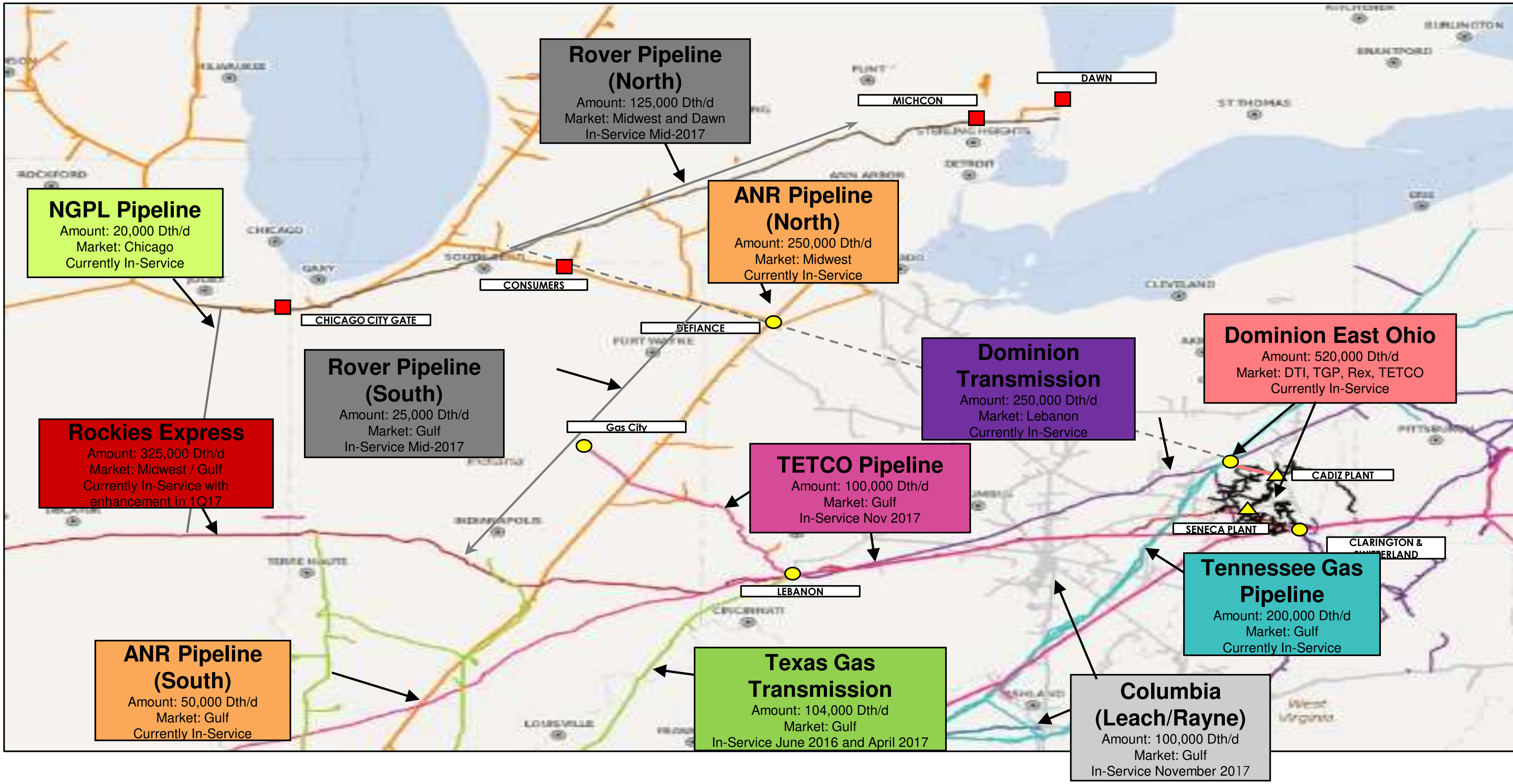


Key Highlights

- **Consistency of the reservoir enables us to stay within the target zone, the Point Pleasant**
  - Highly uniformed stratigraphy and limited reservoir variation
  - Structural simplicity, low dip and minimal faults
  - Petrophysical properties extremely uniform across the play
- **Stratigraphy and structural simplicity allow for highly repeatable results**

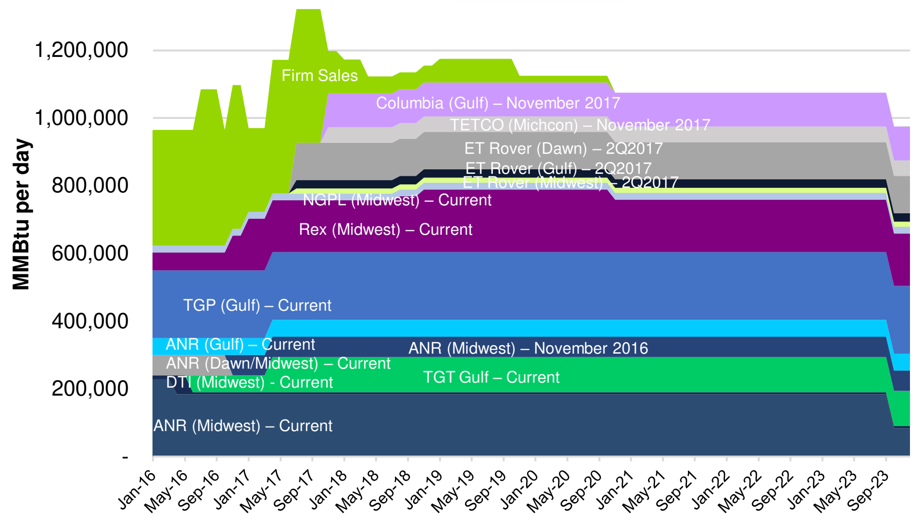
Utica Shale – Diversified End Market Portfolio

Overview

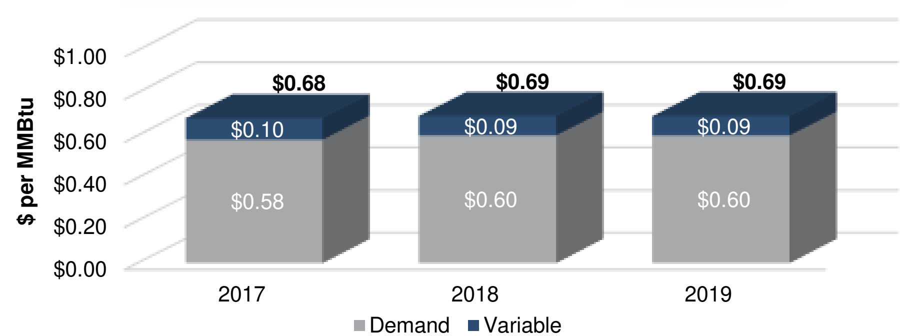


Utica Shale – Firm Transportation and Sales Outlets

Firm Commitments (MMBtu per day)



Firm Transportation Costs ($ per MMBtu)



Overview

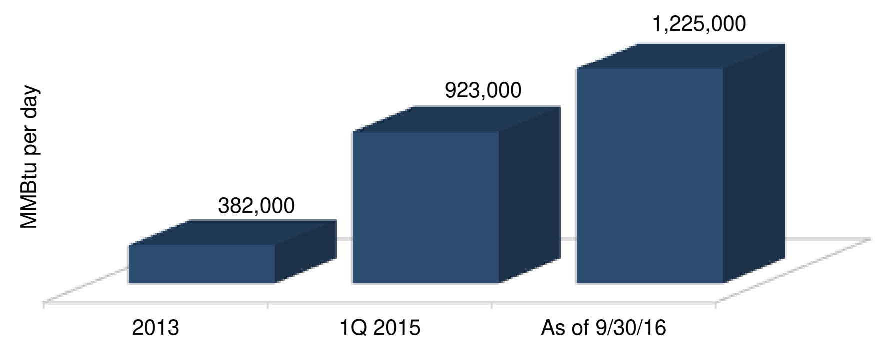
	YE2014	YE2015	YE2016	YE2017 +
		(MMBtu / day)		
Midwest Markets				
ANR Pipeline	184,000	229,000	184,000	244,000
Dominion Transmission Pipeline		11,000	6,000	6,000
NGPL		20,000	20,000	20,000
Rockies Express Pipeline		53,000	103,000	153,000
Rover Pipeline				15,000
TETCO				46,000
Canadian Markets				
ANR Pipeline	60,000	60,000	60,000	
Rover Pipeline				110,000
Gulf Coast Markets				
ANR Pipeline		50,000	50,000	50,000
Tennessee Gas Pipeline		200,000	200,000	200,000
Texas Gas Transmission			50,000	104,000
Rover Pipeline				25,000
Columbia Pipeline				100,000
Firm Sales Agreements				
Dominion South Point	5,000	5,000		
TETCO M2	50,000	75,000	75,000	75,000
Chicago City Gate	50,000			
Fixed Basis	33,000	207,000	257,000	77,000
TOTAL	**382,000**	**910,000**	**1,005,000**	**1,225,000**

Utica Shale – Overview of Firm Portfolio

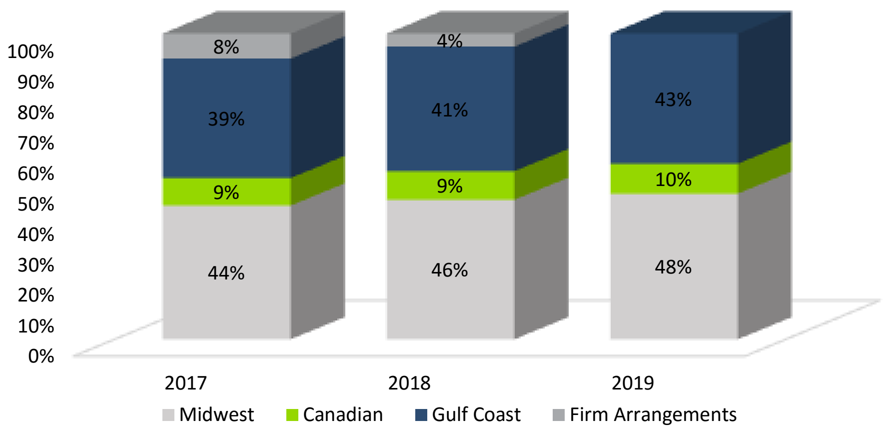
Overview

- Gulfport was a first-mover in securing early access to premium Midwest markets and early transport at low costs out of the basin
- Forecast that Gulfport's in basin exposure will be less than 5% of our 2017 forecasted production
- Expect to sell material volumes above firm portfolio beginning in 2018, when regional pricing is expected to be advantaged relative to costs of transport

YE 2017 Secured Firm Commitments

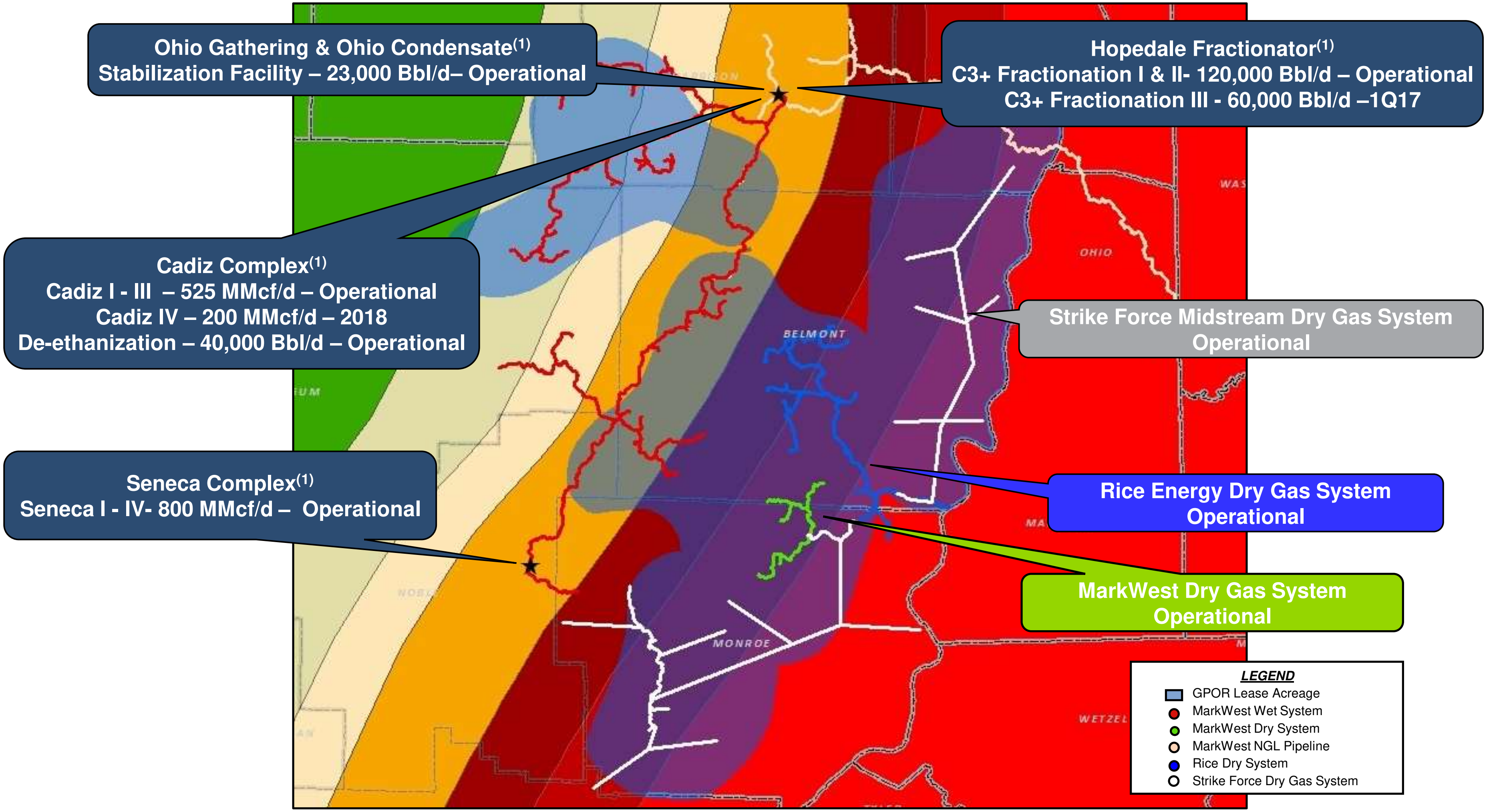


Regional Exposure and Realized Pricing of Firm Portfolio



	2017	2018	2019
NYMEX Strip ($ / MMBtu)	$ 3.34	$ 3.09	$ 2.87
Basis Impact[1] ($/ MMBtu)	$ (0.30)	$ (0.17)	$ (0.18)
Firm Variable Costs ($/ MMBtu)	$ (0.07)	$ (0.09)	$ (0.08)
Firm Demand Costs ($/ MMBtu)	$ (0.42)	$ (0.57)	$ (0.57)
Pre-Hedge Realized Price ($/ MMBtu)	**$ 2.55**	**$ 2.26**	**$ 2.04**
BTU Uplift (MMBtu / Mcf)	$ 0.18	$ 0.16	$ 0.14
Pre-Hedge Realized Price ($/ Mcf)	**$ 2.73**	**$ 2.42**	**$ 2.18**
Total Firm Expense + Basis ($ / MMBtu)	**$ (0.79)**	**$ (0.83)**	**$ (0.83)**
Total Firm Expense + Basis ($ / Mcf)	**$ (0.61)**	**$ (0.67)**	**$ (0.69)**

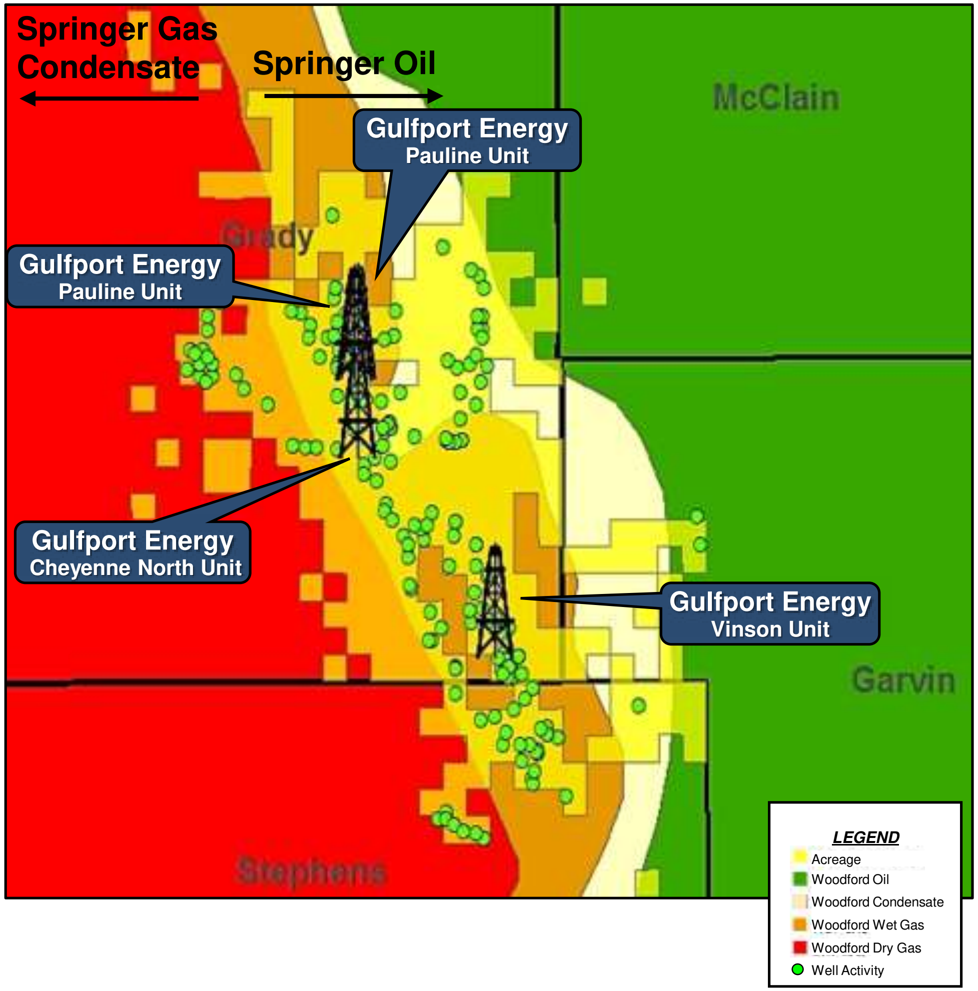
Utica Shale – Midstream Infrastructure



1) Per MPLX Energy Investor Presentation on January 10, 2017.

SCOOP Asset Overview

SCOOP Overview



Asset Overview

- **~85,000[1] effective net acres in the core of the SCOOP play in Grady, Stephens and Garvin Counties, OK**
  - Includes ~46,400 Woodford and 38,600 Springer acres in over-pressure liquids rich to dry gas windows of the play
    - Operates ~80% of Woodford net acres w/ an average 70% WI and an average 80% NRI
  - ~82% Woodford and ~79% Springer acreage held by production
- **Deep inventory of delineated, high-return drilling locations at current strip pricing**

2016 Activities Update[2]

- **Average net production of 183.4 MMcfepd**
  - ~68% natural gas, 21% natural gas liquids and 11% oil

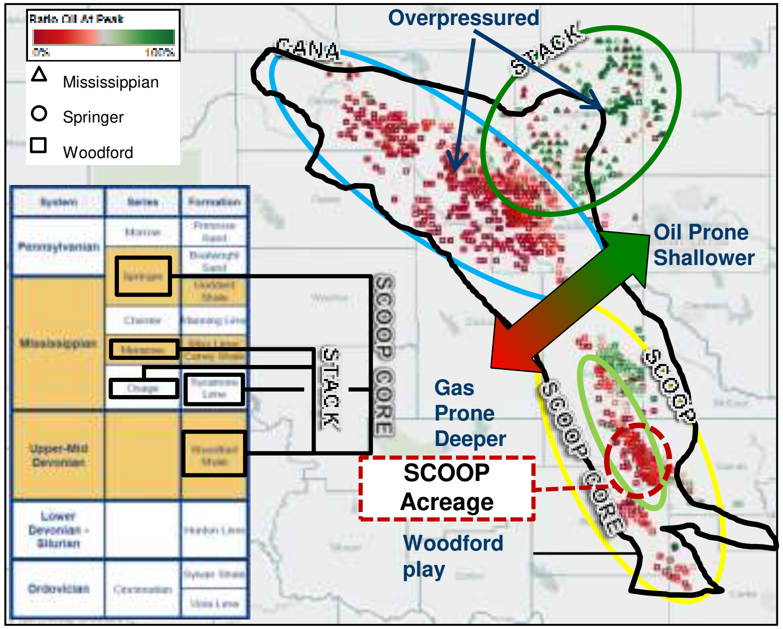
2017 Planned Activities[3]

- **Currently running 4 gross operated rigs**
  - Plan to run ~4 operated rigs and participate in non-operated activity during 2017
- **Operated Activity**
  - Drill 19 to 21 gross (16 to 18 net) wells
  - Turn-to-sales 17 to 19 gross (14 to 16 net) wells
- **Non-Operated Activity**
  - Drill 10 to 12 gross (1 to 2 net) wells
  - Turn-to-sales 10 to 12 gross (1 to 2 net) wells

Note: Please refer to page 2 for detail on forward looking statements.
1) Acreage as of 12/13/16.
2) Fourth quarter of 2016 net production per Vitruvian Lease Operating Statement.
3) As of 2/13/17.

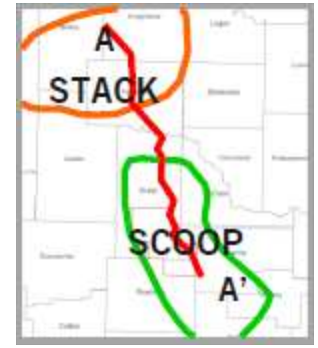
SCOOP – Geologic Overview

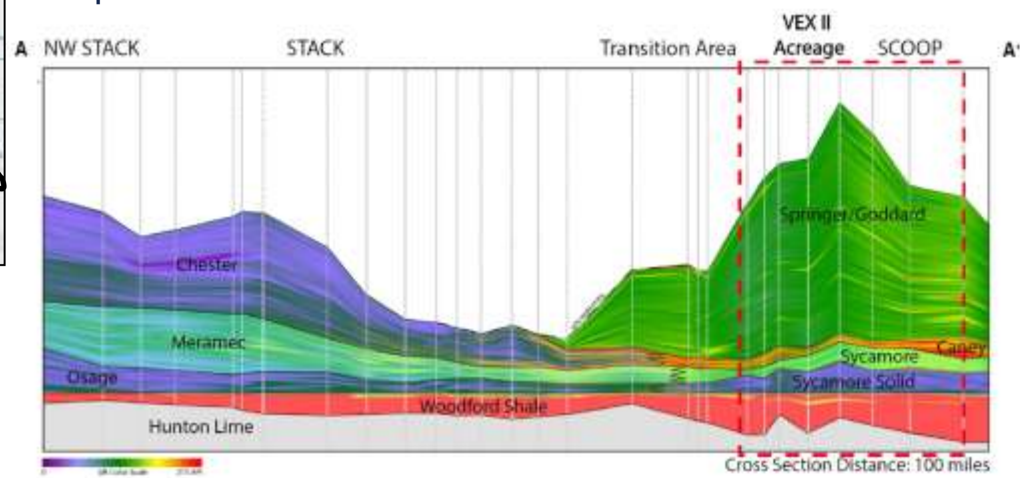
Overview



Regional Stratigraphy

- Woodford was deposited on an erosional surface and varies in thickness, increasing to the south into the SCOOP
- Sycamore section is the basinal time-equivalent to the Meramec and Osage units in the STACK
- Springer group thins to the north and east and is removed by an erosional surface
- Depositional fairway of high quality reservoir is over 2,000 ft. thick and covers the Woodford, Springer and Sycamore plays – with superior porosity and permeability and over-pressured hydrocarbons yield top flow rates





SCOOP acreage contains the thickest Woodford section of the SCOOP/STACK play enhanced by a substantial resource in the Springer

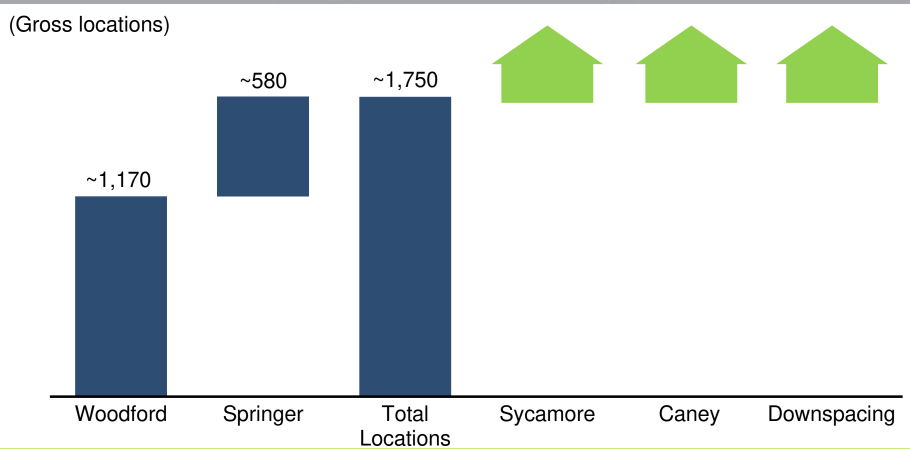
Source: IHS performance evaluator, investor presentations.

SCOOP – Large Stacked Multi-Pay Inventory

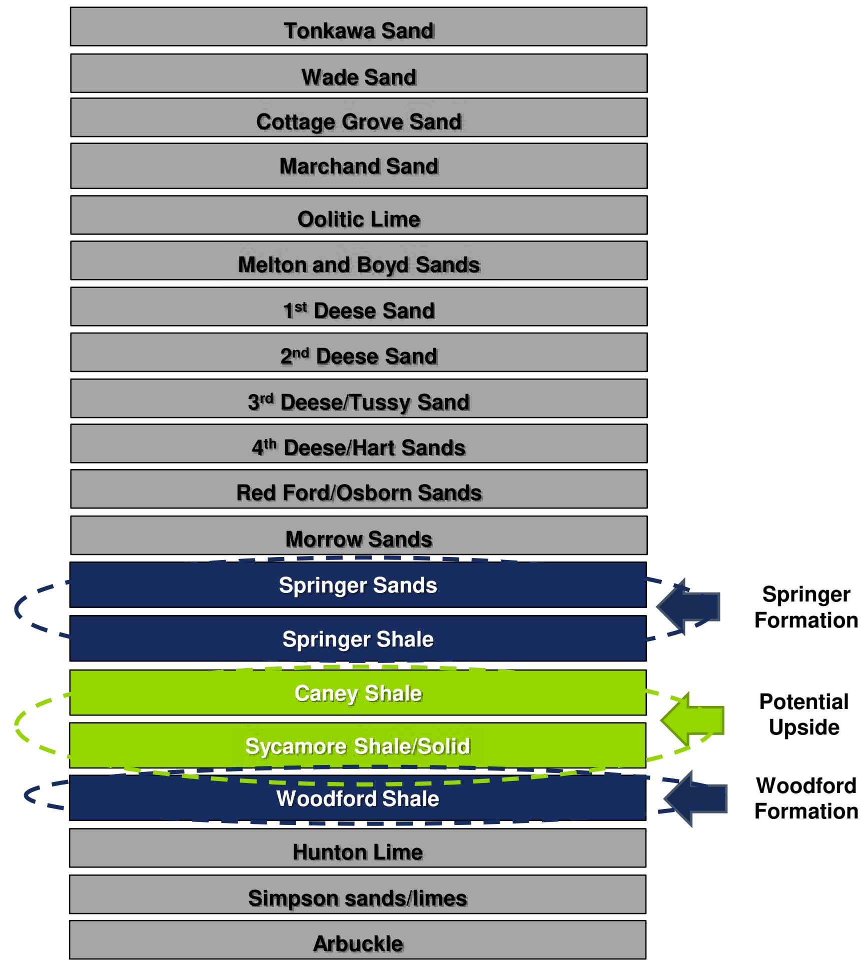
Overview

- **46,400 net surface acres located in the heart of SCOOP condensate and over-pressured gas windows with exposure to stacked pay zones**
  - ~1,180 gross identified locations in the Woodford formation
  - ~580 gross identified locations in the Springer formation
  - Additional upside from Sycamore, Caney and downspacing
- **~15 years of identified drillable locations with significant upside potential**
- **Highly delineated play with high well and seismic control**
  - Approximately 3,000 producing wells
  - Well understood reservoir dynamics and geological characteristics

Significant Inventory



Formation Overview



SCOOP – Recent Well Results

Cheyenne 8-10X15H
Vitruvian
Norm IP30: 1,635 Mcfe/d/1,000'
Lateral Length : 7,026'

Tyemax Bia 1-35RXH
Marathon
Norm IP30: 2,587 Mcfe/d/1,000'
Lateral Length : 7,286'

Lane 13-24-1XH
Apache
Norm IP30: 1,534 Mcfe/d/1,000'
Lateral Length : 5,293'

Newy 6-25-24-13XH
Continental
Norm IP30: 1,595 Mcfe/d/1,000'
Lateral Length : 10,991'

Newy 7-25-24-13XH
Continental
Norm IP30: 1,778 Mcfe/d/1,000'
Lateral Length : 10,710'

Poteet 9-17-20X
Continental
Norm IP30: 1,776 Mcfe/d/1,000'
Lateral Length : 8,528'

Poteet 7-17-20X
Continental
Norm IP30: 1,673 Mcfe/d/1,000'
Lateral Length : 8,088'

Fowler 4N6W 3-9X16H
Vitruvian
Norm IP30: 1,526 Mcfe/d/1,000'
Lateral Length : 8,700'

Parks 4-14X23H
Vitruvian
Norm IP30 : 1,522 Mcfe/d/1,000'
Lateral Length : 7,417'

Anita Fowler 1-27X26H
Vitruvian
Norm IP30 : 3,166 Mcfe/d/1,000'
Lateral Length : 5,950'

Castle 1-35H
Vitruvian
Norm IP30: 1,988 Mcfe/d/1,000'
Lateral Length : 4,661'

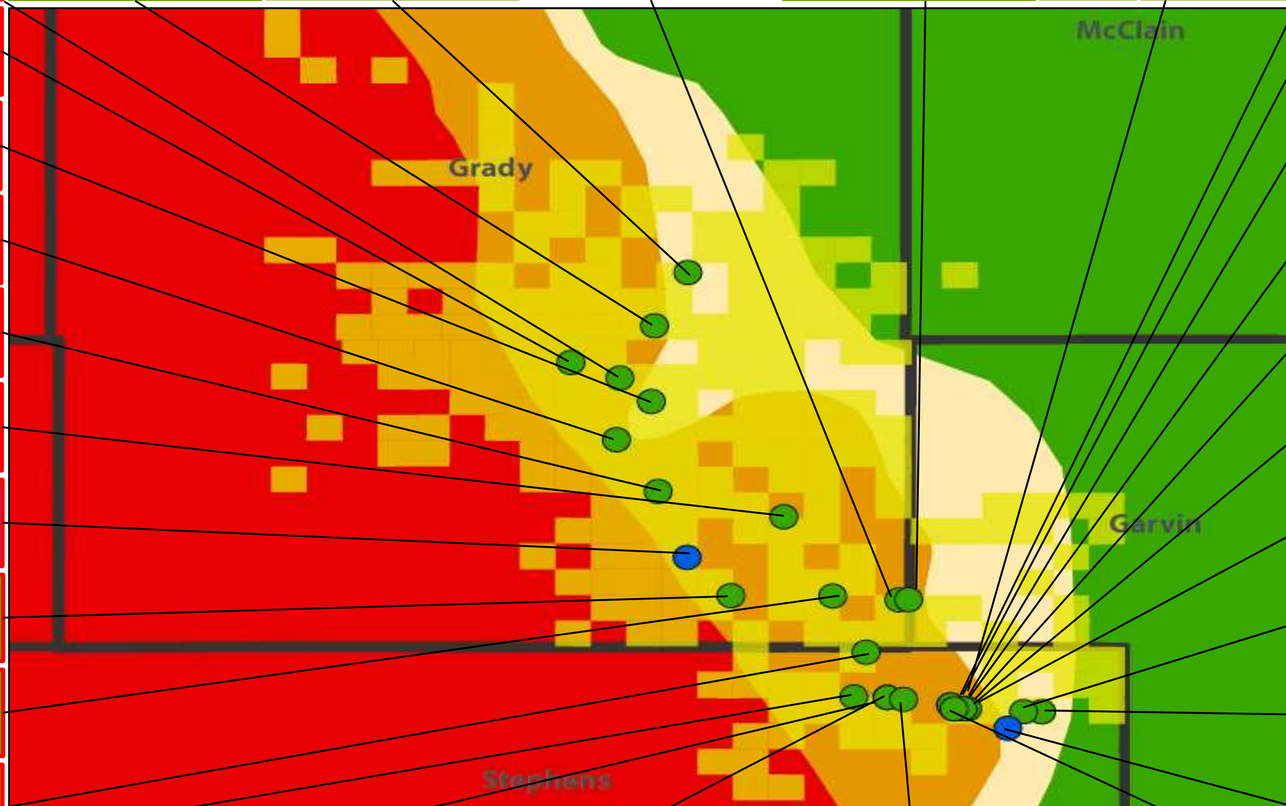
Burnside 3-09X16H
Vitruvian
Norm IP30: 1,530 Mcfe/d/1,000'
Lateral Length : 7,529'

Wayne 1-13X12
Vitruvian
Norm IP30: 1,565 Mcfe/d/1,000'
Lateral Length : 6,802'

Murphree 1-19H
Vitruvian
Norm IP30: 2,109 Mcfe/d/1,000'
Lateral Length : 4,759'

Vinson 1-22H
Vitruvian
Norm IP30: 1,515 Mcfe/d/1,000'
Lateral Length : 4,045'

Turner 1-35H
Vitruvian
Norm IP30: 2,055 Mcfe/d/1,000'
Lateral Length : 3,703'



Poteet 10-17-20X
Continental
Norm IP30: 2,097 Mcfe/d/1,000'
Lateral Length : 7,098

Poteet 4-17-20X
Continental
Norm IP30: 1,905 Mcfe/d/1,000'
Lateral Length : 7,849'

Poteet 8-17-20X
Continental
Norm IP30: 2,815 Mcfe/d/1,000'
Lateral Length : 4,866'

Poteet 5-17-20X
Continental
Norm IP30: 1,965 Mcfe/d/1,000'
Lateral Length : 8,113'

Poteet 3-17-20X
Continental
Norm IP30: 1,770 Mcfe/d/1,000'
Lateral Length : 7,283'

Poteet 6-17-20X
Continental
Norm IP30: 1,843 Mcfe/d/1,000'
Lateral Length : 8,110'

Vanarkel 3-15-10XH
Continental
Norm IP30: 1,547 Mcfe/d/1,000'
Lateral Length : 7,208'

Vanarkel 7-1510XH
Continental
Norm IP30: 1,622 Mcfe/d/1,000'
Lateral Length : 7,562'

Jarred 1H-9X
Newfield
Norm IP30: 1,566 Mcfe/d/1,000'
Lateral Length : 4,745'

Hussey 3-11H
Marathon
Norm IP30: 2,826 Mcfe/d/1,000'
Lateral Length : 3,410'

Turner Trust 2N5W 1-12H
Vitruvian
Norm IP30: 1,547 Mcfe/d/1,000'
Lateral Length : 4,082'

Turner Trust 3-12H
Vitruvian
Norm IP30: 1,912 Mcfe/d/1,000'
Lateral Length : 4,507'

Snodgrass 1-12H
Vitruvian
Norm IP30: 1,510 Mcfe/d/1,000'
Lateral Length : 4,764'

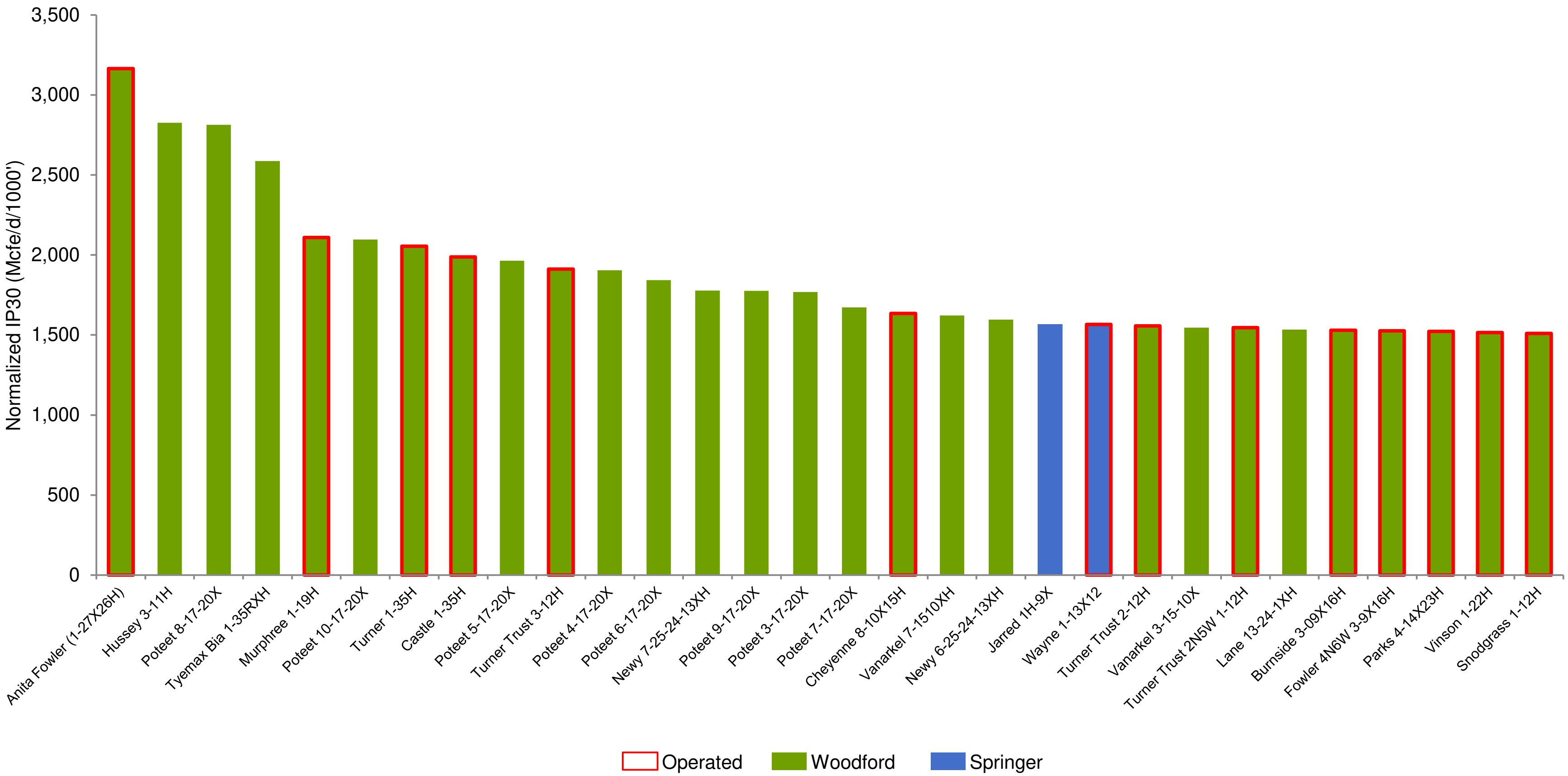
Turner Trust 2-12H
Vitruvian
Norm IP30: 1,557 Mcfe/d/1,000'
Lateral Length : 3,960'

Vitruvian
Woodford
Springer

SCOOP acreage is central to the strongest performing wells

Source: Vitruvian provided data and publicly available information.

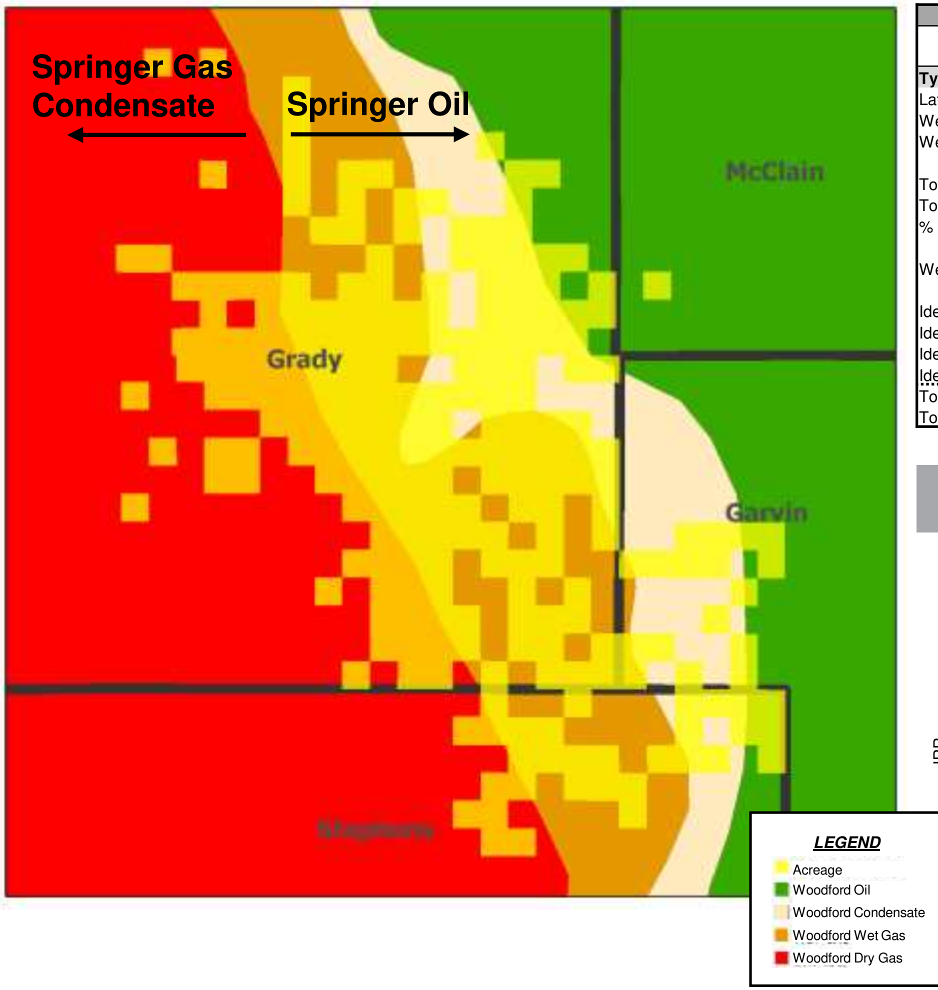
SCOOP – List of High Quality Results Continues to Expand



Operated wells make up half of the top well results

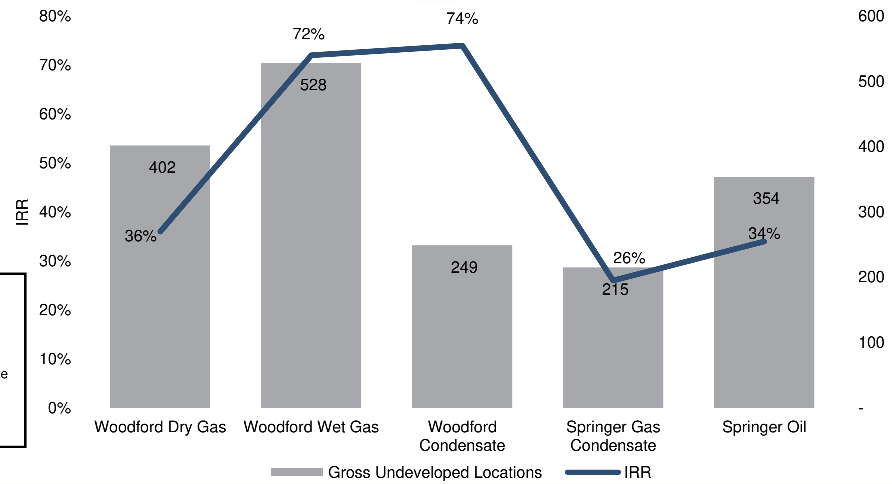
Source: Vitruvian provided data and publicly available information.

SCOOP - Type Curve Assumptions



	Woodford			Springer	
	Dry Gas	Wet Gas	Condensate	Springer Gas Condensate	Springer Oil
Type Curve Assumptions					
Lateral Length	7,500	7,500	7,500	7,500	7,500
Well Cost ($MM)	$12.3	$10.5	$9.7	$10.7	$11.0
Well Cost ($ per foot)	$1,633	$1,395	$1,295	$1,429	$1,461
Total EUR (Bcfe / 1,000)	2.6	2.6	1.5	1.7	0.8
Total EUR (Bcfe)	19.8	19.7	11.5	12.7	5.8
% Gas	100%	76%	52%	78%	22%
Wells per section	8	8	8	6	6
Identified Gross Operated Locations	99	218	39	96	88
Identified Net Operated Locations	44	157	22	59	54
Identified Gross Non-Op Locations	303	310	210	119	266
Identified Net Non-Op Locations	21	25	11	13	16
Total Identified Gross Locations	402	528	249	215	354
Total Identified Net Locations	65	182	33	72	70

Single Well Economics[1,2]



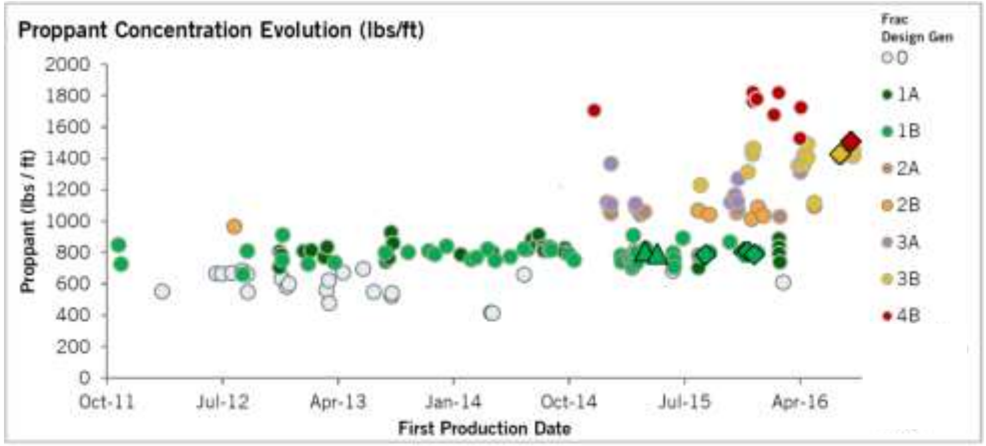
Note: See appendix slide 42 for detailed assumptions used to generate single well IRRs.
1) Assumes ethane rejection.
2) Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.

SCOOP - Significant Upside From Enhanced Completions

Overview

- **From 2012 to January 2015 there has been very little progression in Woodford SCOOP completions**
- **In Mid-2014 core CANA Woodford operators increased completion job size with significant success**
  - SCOOP operators followed suit with Gen 2 & Gen 3 completions
- **The best results are coming from operators that employ mostly slickwater completions**
- **The Anita Fowler 1-27X26H, completed with Gen 4B design, is one of the best Woodford wells to date.**
- **Normalizing the completion design for formation thickness indicates that the stimulation intensity in the Woodford lags behind the Utica indicating there is substantial room for improvement**

Proppant Concentration Evolution (lbs/ft)



Generation	0	1A	1B	2A	2B	3A	3B	4A	4B
Proppant	400-700	700-950	400-950	950-1100	950-1100	1100-1500	1100-1500	1500-2000	1500-2000
Fluid Type	Varies	Gel / X-link	Slickwater / Linear Gel	Gel / X-link	Slickwater / Linear Gel	Gel / X-link	Slickwater / Linear Gel	Gel / X-link	Slickwater / Linear Gel
Proppant Concentration (lbs/gal)	0.4-1.0	0.6-1.2	0.4-0.5	1.1-1.5	0.5-0.6	1.2-1.6	0.5-0.7	1.2-1.6	0.7-0.8
Stage Spacing (ft)	250-450	200-400	280-330	200	280-330	200	280-330	200	200-300
Cluster Spacing (ft)	60-120	60-90	75-80	50	50-80	50	75-80	50	75-80
Total Wells	25	27	61	20	8	3	15	0	9

Seeking to apply Utica completions design expertise to the SCOOP to drive performance uplift

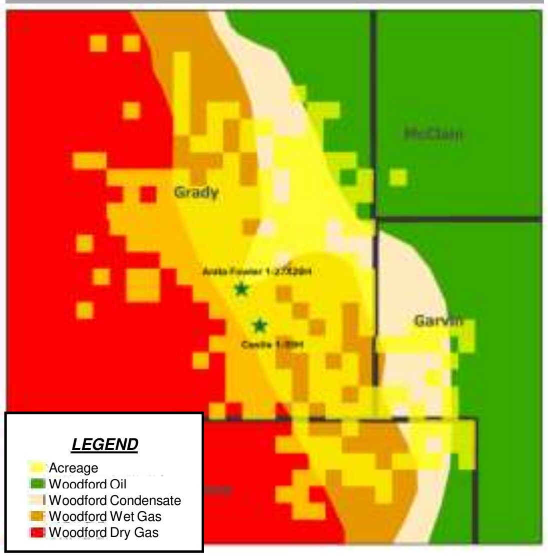
1) IHS Energy News on Demand Mid-Continent Oklahoma, September 19, 2016.

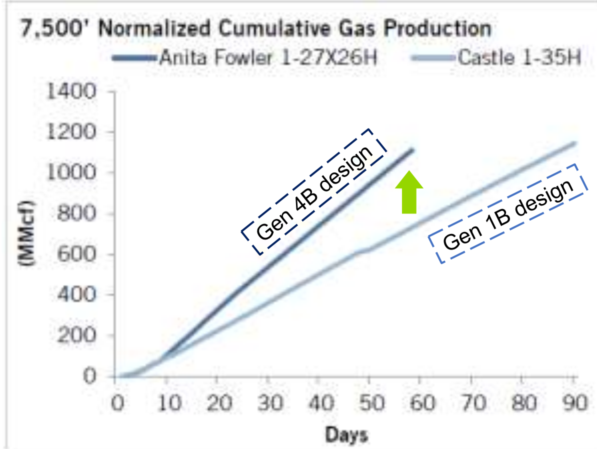
SCOOP - Completion Case Study

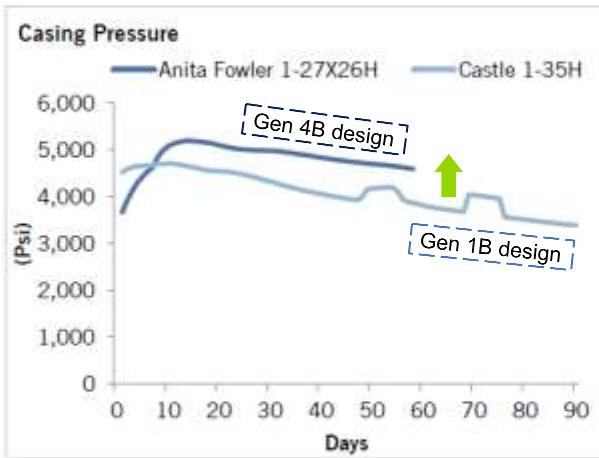
Key Points

- **Castle 1-35H was completed March 2015 with Gen 1B design on 4,661 ft. lateral**
- **Anita Fowler 1-27X26H was completed in July 2016 with a Gen 4B design on all stages**
- **Anita Fowler well delivered 54% improvement in IP30 with an additional 500 psi in flowing casing pressure**

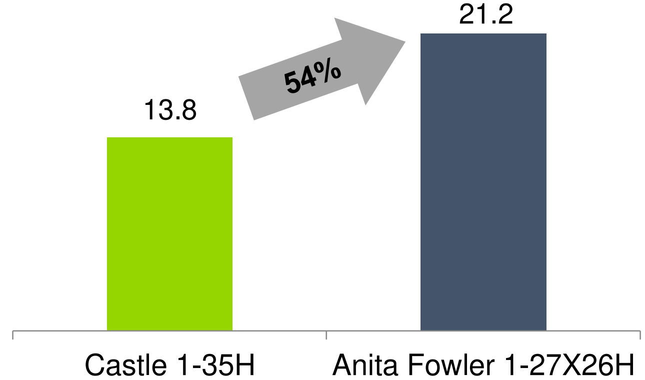
Locator Map



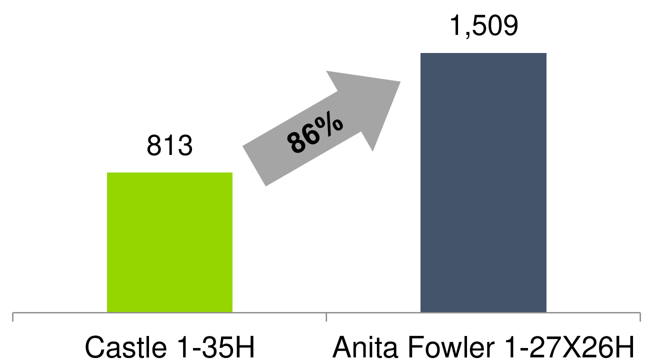




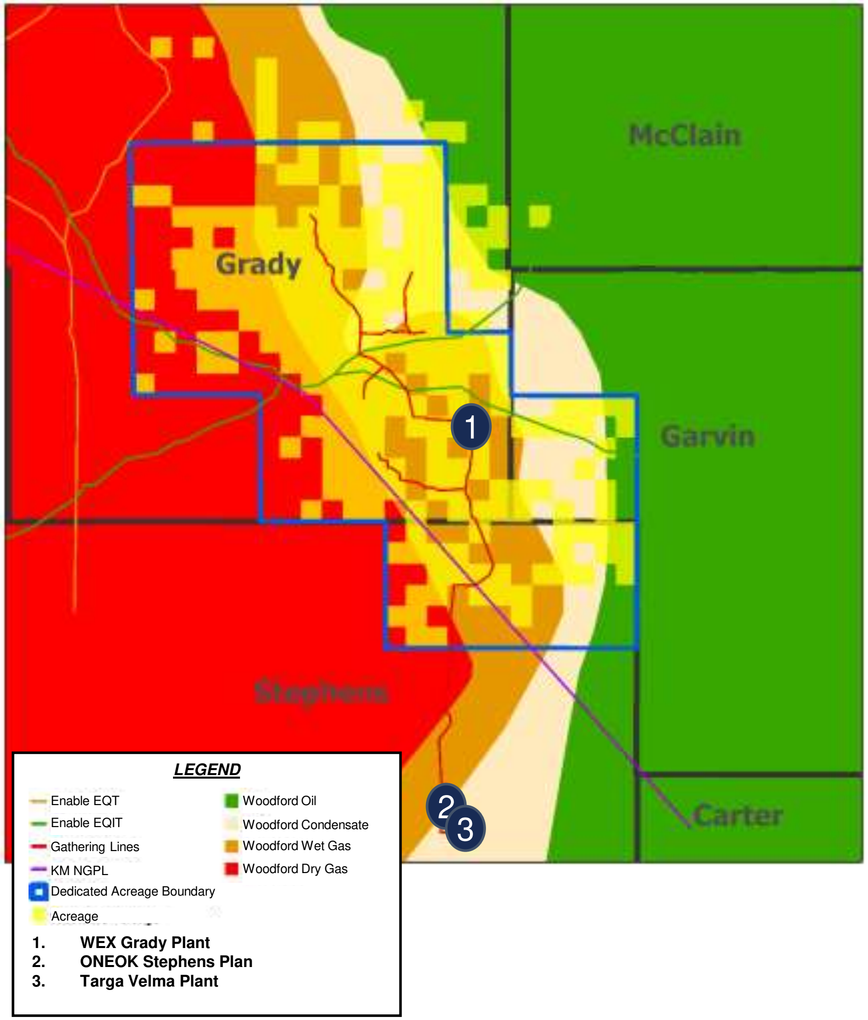
Normalized 7,500' 30-Day IP (MMcf/d)



Proppant (Lbs / ft)



SCOOP – Midstream Gathering and Processing Overview



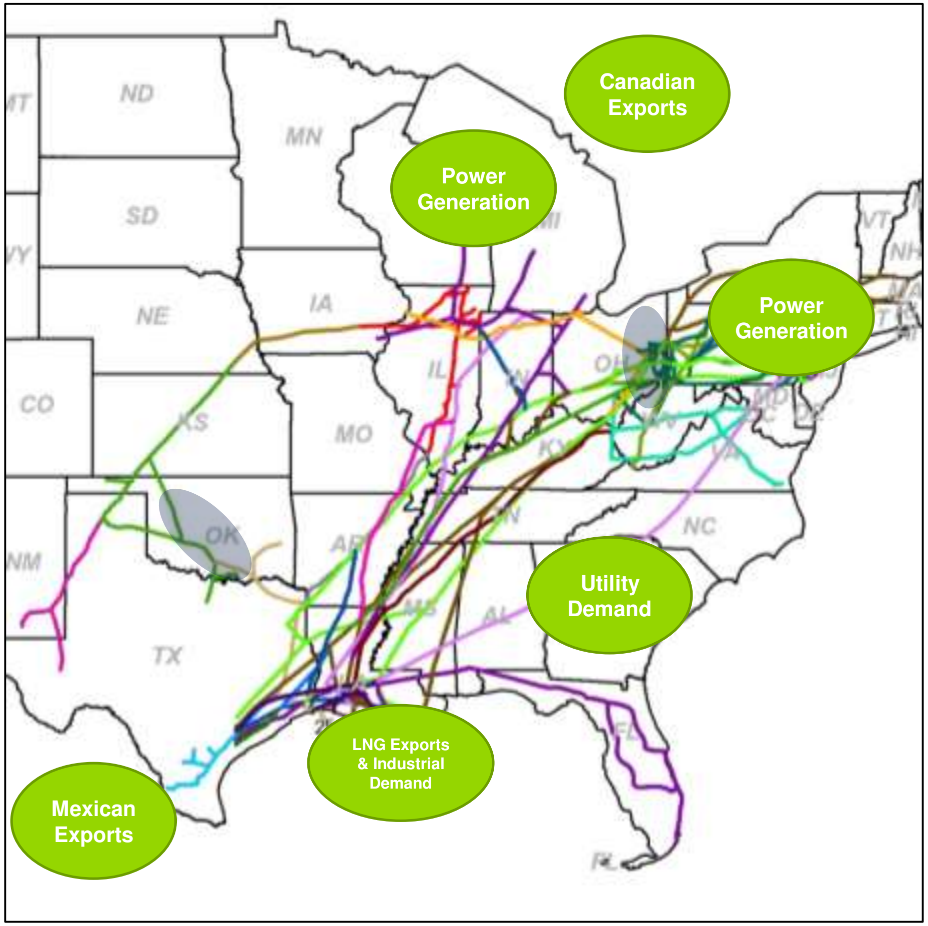
Key Highlights

- **Acreage dedication arrangement for all horizontal development to Woodford Express ("WEX") for gathering and processing**
  - Competitive gathering and processing contracts with fixed fees, fuels and recoveries
- **Gathering overview:**
  - Recently laid 16" and 20" trunk lines throughout the dedication area
  - Operating pressure no greater than 600# at the pad
- **Processing overview:**
  - Primary connection to WEX Grady Plant
    - Existing 210 MMcf/d processing capacity
      - Planned expansion with a third 200 MMcf/d train in 4Q2017
    - Additional connections to ONEOK Stephens and Targa Velma processing plants
- **Takeaway overview:**
  - **Residue Gas:** Enable EOIT, EGT and NGPL (will also include Midship in 1Q2019)
    - Currently have 170,000+ MMBtu/d of firm arrangements, including deliveries to Bennington and Perryville
    - Directly connected into NGPL
  - **NGLs:** DCP Southern Hills

SCOOP – Midstream Marketing Overview

Key Highlights

- **Low cost supply basin centrally located and advantaged by proximity to growing demand centers in the Gulf Coast regions**
  - LNG
  - Mexican exports
  - Industrial demand
  - Increasing power generation and utility loads
- **Asset base located closer to physical hubs which typically set benchmark pricing**
  - Henry Hub for natural gas
  - Mont Belvieu for NGLs
  - Cushing for crude
- **Favorable transport costs via pipe, rail or truck to these premium markets**
- **Diversifies risk by increasing liquids exposure, which provides uplift to realized pricing and enhances corporate margins**



Utica Appendix

Utica Shale – Type Curve Assumptions

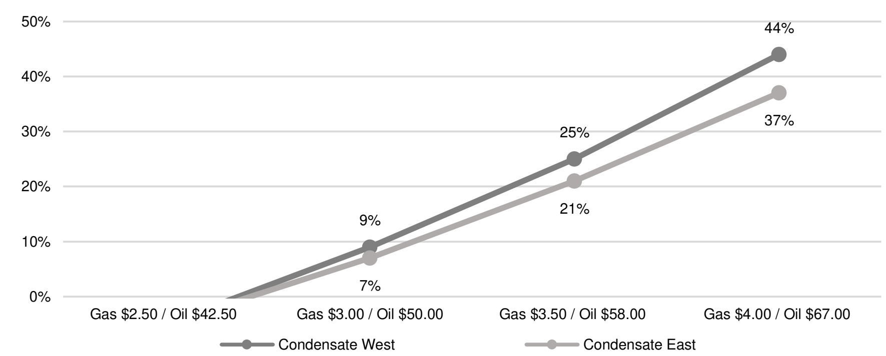
	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Identified Gross Locations[4]	**144**	**87**	**128**	**189**	**449**	**273**
Identified Net Locations	**108**	**65**	**96**	**141**	**337**	**205**
Type Curve Assumptions						
Lateral Length (ft.)	8,000	8,000	8,000	8,000	8,000	8,000
Initial Gas Production (Mcf/d)[1]	2,500	3,300	12,000	14,000	14,000	14,000
Flat Period (days)	90	90	274	243	274	304
Shrink	13%	13%	12%	N/A	N/A	N/A
NGL Yield (Bbls/MMcf)	71	65	44	N/A	N/A	N/A
Residue BTU	1,140	1,135	1,095	1,070	1,060	1,050
Pre-Processed EUR (Bcfe)	4.9	6.7	14.0	17.2	19.0	20.7
Pre-Processed % Gas	56%	78%	100%	100%	100%	100%
Post-Processed EUR (Bcfe / 1,000')[2]	0.7	1.0	2.0	2.2	2.4	2.6
Post-Processed EUR (Bcfe)[2]	5.7	8.1	16.0	17.2	19.0	20.7
Oil (MBbl)	358	249	7	-	-	-
NGL (MBbl)	196	338	614	-	-	-
Residue Gas (MMcf)	2,389	4,527	12,227	17,202	18,952	20,711
Post Processed % Gas	42%	56%	77%	100%	100%	100%
Unhedged Pricing [3]						
Gas ($ / MMBtu off NYMEX)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)
Condensate ($ / Bbl off WTI)	$ (10.00)	$ (10.00)	$ (10.00)	$ (10.00)	$ (10.00)	$ (10.00)
NGL (% of WTI)	30%	30%	30%	30%	30%	30%
Operating Expenses						
OPEX - Year 1						
Fixed ($/well/mo)	$ 25,000	$ 25,000	$ 15,000	$ 12,500	$ 12,500	$ 12,500
Variable ($/Mcf)	$ 0.17	$ 0.15	$ 0.05	$ 0.05	$ 0.05	$ 0.05
OPEX - Year 2						
Fixed ($/well/mo)	$ 20,000	$ 20,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Variable ($/Mcf)	$ 0.08	$ 0.07	$ 0.02	$ 0.02	$ 0.02	$ 0.02
OPEX - Year 3+						
Fixed ($/well/mo)	$ 15,000	$ 15,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Variable ($/Mcf)	$ 0.09	$ 0.07	$ 0.02	$ 0.02	$ 0.02	$ 0.02
Gathering & Compression ($/Mcf)	$ 0.64	$ 0.64	$ 0.56	$ 0.40	$ 0.40	$ 0.40
Processing ($/Mcf)	$ 0.65	$ 0.65	$ 0.52	N/A	N/A	N/A
Severance Tax	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Well Cost Assumptions						
Well Cost ($MM)	$ 7.7	$ 7.7	$ 8.3	$ 8.5	$ 8.7	$ 8.9
Well Cost ($ per foot)	$ 962	$ 964	$ 1,035	$ 1,060	$ 1,085	$ 1,110

Note: See appendix slide 39 for detailed assumptions used to net undeveloped locations.
1) Represents 24-hour rate well head gas production.
2) Assumes ethane rejection.
3) Includes transportation costs and basis differentials.
4) Assumes net undeveloped locations grossed up from 75% working interest.

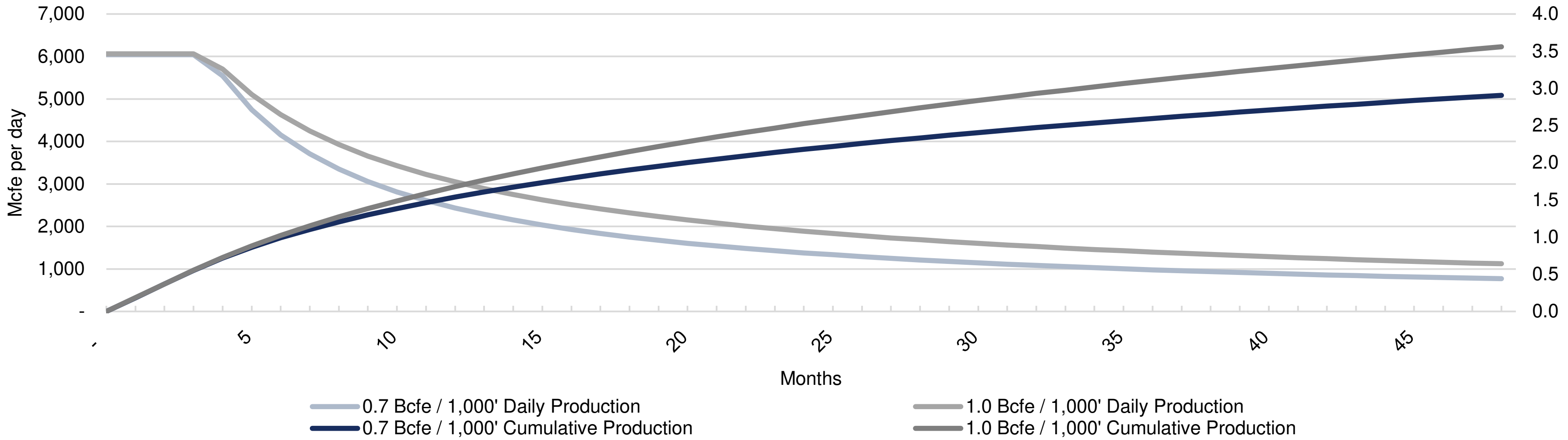
Utica Shale – Condensate Window Type Curves

Type Curve Assumptions[1]	Condensate	
	West	East
Lateral Length	8,000	8,000
Well Cost ($MM)	$7.7	$7.7
Well Cost ($ per foot)	$962	$964
Total EUR (Bcfe / 1,000)	0.7	1.0
Total EUR (Bcfe)	5.7	8.1
% Gas	42%	56%
Assumed Well Spacing (ft)	600	600
Gross Undeveloped Locations[2]	144	87
Net Undeveloped Locations	108	65

Single Well Economics[1]



Condensate Type Curves[1]

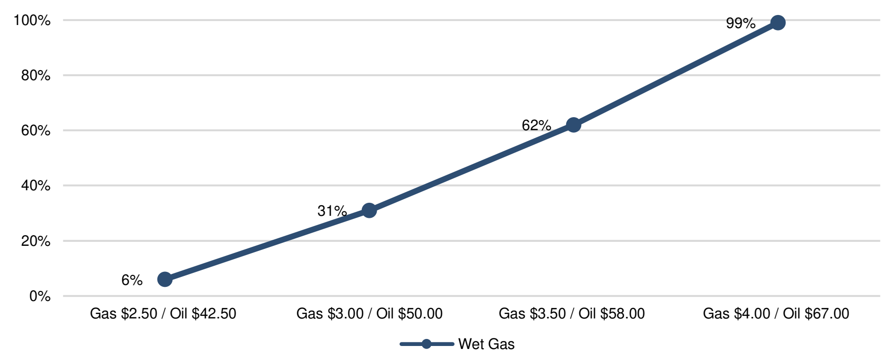


Note: See appendix slide 35 for detailed assumptions used to generate single well IRRs and slide 39 for net undeveloped locations.
1) Assumes ethane rejection.
2) Assumes net undeveloped locations grossed up from 75% working interest.

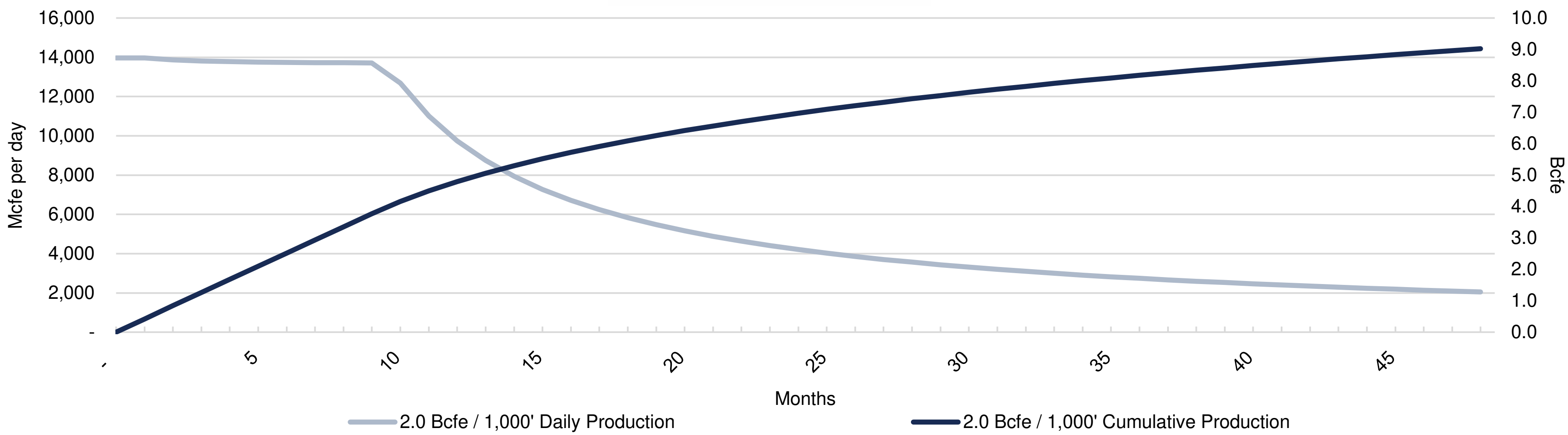
Utica Shale – Wet Gas Window Type Curves

Type Curve Assumptions[1]	Wet Gas
Lateral Length	8,000
Well Cost ($MM)	$8.3
Well Cost ($ per foot)	$1,035
Total EUR (Bcfe / 1,000)	2.0
Total EUR (Bcfe)	16.0
% Gas	77%
Assumed Well Spacing (ft)	1,000
Gross Undeveloped Locations[2]	128
Net Undeveloped Locations	96

Single Well Economics[1]



Wet Gas Type Curves[1]



Note: See appendix slide 35 for detailed assumptions used to generate single well IRRs and slide 39 for net undeveloped locations.

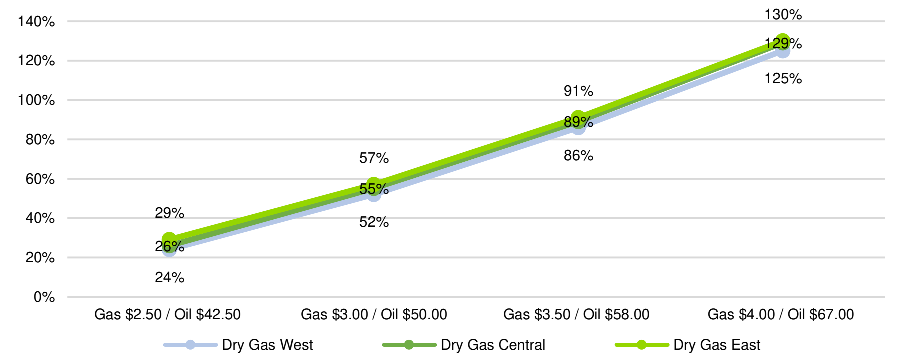
1) Assumes ethane rejection.

2) Assumes net undeveloped locations grossed up from 75% working interest.

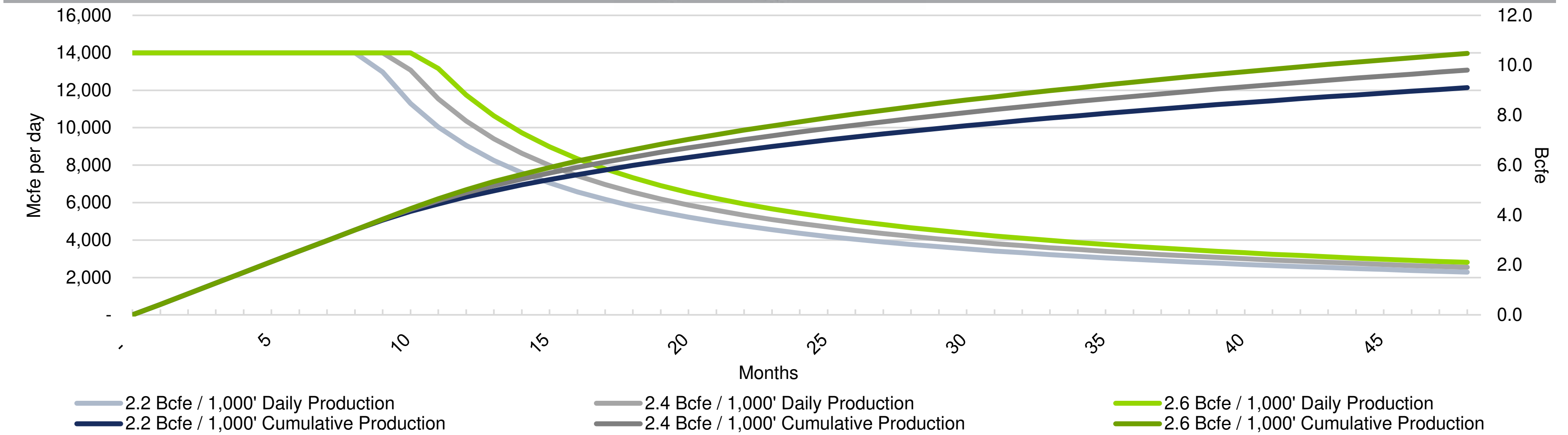
Utica Shale – Dry Gas Window Type Curves

Type Curve Assumptions[1]	Dry Gas West	Dry Gas Central	Dry Gas East
Lateral Length	8,000	8,000	8,000
Well Cost ($MM)	$8.5	$8.7	$8.9
Well Cost ($ per foot)	$1,060	$1,085	$1,110
Total EUR (Bcfe / 1,000)	2.2	2.4	2.6
Total EUR (Bcfe)	17.2	19.0	20.7
% Gas	100%	100%	100%
Assumed Well Spacing (ft)	1,000	1,000	1,000
Gross Undeveloped Locations[2]	189	449	273
Net Undeveloped Locations	141	337	205

Single Well Economics[1]



Dry Gas Type Curves[1]



Note: See appendix slide 35 for detailed assumptions used to generate single well IRRs and slide 39 for net undeveloped locations.
1) Assumes ethane rejection.
2) Assumes net undeveloped locations grossed up from 75% working interest.

Additional Disclosures

Net Undeveloped Locations[1]

	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Net Undeveloped Location Summary						
Net Acres	14,741	10,089	28,476	32,940	79,397	43,764
Lateral Length	8,000	8,000	8,000	8,000	8,000	8,000
Location Spacing	600	600	1,000	1,000	1,000	1,000
Net Potential Locations	134	92	155	179	432	238
Less approximate wells turned to sales[2]	14	19	49	22	58	10
Unrisked Net Undeveloped Locations	120	72	107	157	374	228
Estimated Risking Factor	10%	10%	10%	10%	10%	10%
Risked Net Undeveloped Locations	**108**	**65**	**96**	**141**	**337**	**205**

Determination of Identified Drilling Locations as of February 13, 2017:

Net Undeveloped Locations: Calculated by taking Gulfport's total net acreage and multiplying such amount by a risking factor which is then divided by Gulfport's expected well spacing. Gulfport then subtracts net producing wells to arrive at undeveloped net drilling locations.

Net Undeveloped Utica Condensate West Locations: Gulfport assumes these locations have 8,000 foot laterals and 600 foot spacing between wells which yields approximately 110 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Condensate East Locations: Gulfport assumes these locations have 8,000 foot laterals and 600 foot spacing between wells which yields approximately 110 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Wet Gas Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas West Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas Central Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas East Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

1) All acreage as of 2/13/17.
2) Wells turned to sales as of 12/31/16.

Northeast Pipeline Expansion List

	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19
NE Marcellus to Northeast																				
Transco NE Connector Project	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
TGP Rose Lake Expansion	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
TGP Niagara Expansion				158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158
NFG West Side Expansion				175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
TGP Susquehanna West Project												145	145	145	145	145	145	145	145	145
Constitution Pipeline																650	650	650	650	650
AGT Access Northeast																925	925	925	925	925
TGP NED (NE Energy Direct Project)																				
Total	**330**	**330**	**330**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**808**	**808**	**808**	**808**	**2,383**	**2,383**	**2,383**	**2,383**	**2,383**
NE Marcellus to Mid-Atlantic/South																				
TCO East Side Expansion				310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
TRANSCO Leidy Southeast Project				525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
Transco Diamond East														500	500	500	500	500	500	500
Transco Atlantic Sunrise															1,700	1,700	1,700	1,700	1,700	1,700
PennEast Pipeline															1,000	1,000	1,000	1,000	1,000	1,000
Total				**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**1,335**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**
Wet Marcellus & Utica Takeaway projects to the MidCon and Canada																				
REX Seneca Lateral Phase 1	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
REX Seneca Lateral Phase 2	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
REX East-to-West			1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
TETCO Uniontown to Gas City				425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
ANR Glen Karn				134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
EQT Ohio Valley Connector								850	850	850	850	850	850	850	850	850	850	850	850	850
REX Zone 3 Capacity Enhancement								800	800	800	800	800	800	800	800	800	800	800	800	800
NFG Northern Access 2016											497	497	497	497	497	497	497	497	497	497
TETCO Lebanon													180	180	180	180	180	180	180	180
Nexus													1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Rover Pipeline Phase I												737	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210
Rover Pipeline Phase II														1,040	1,040	1,040	1,040	1,040	1,040	1,040
TETCO M2M																1,000	1,000	1,000	1,000	1,000
Total	**600**	**600**	**1,800**	**2,359**	**2,359**	**2,359**	**2,359**	**4,009**	**4,009**	**4,009**	**4,506**	**5,243**	**8,396**	**9,436**	**9,436**	**10,436**	**10,436**	**10,436**	**10,436**	**10,436**
Wet Marcellus & Utica Takeaway projects to the MidAtlantic and the South																				
TETCO TEAM 2014	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
TETCO TEAM South	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TCO West Side Expansion	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444
TETCO OPEN				550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
TGP Broad Run Flexibility				590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590
TGT OH-LA Access							626	626	626	626	626	626	626	626	626	626	626	626	626	626
TETCO Gulf Market Expansion Ph 1								250	250	250	250	250	250	250	250	250	250	250	250	250
TGT Northern Supply Access										384	384	384	384	384	384	384	384	384	384	384
TETCO Adair Southwest													200	200	200	200	200	200	200	200
TETCO Access South													320	320	320	320	320	320	320	320
TCO Leach Express													1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530
TGP SW Louisiana Supply Project														900	900	900	900	900	900	900
TGP Broad Run Expansion																200	200	200	200	200
TCO Mountaineer Xpress																2,700	2,700	2,700	2,700	2,700
EQT Mountain Valley																2,000	2,000	2,000	2,000	2,000
TCO WB Xpress																1,300	1,300	1,300	1,300	1,300
Dominion Atlantic Coast Pipeline																				1,500
Total	**1,344**	**1,344**	**1,344**	**2,484**	**2,484**	**2,484**	**3,110**	**3,360**	**3,360**	**3,744**	**3,744**	**3,744**	**5,794**	**6,694**	**6,694**	**12,894**	**12,894**	**12,894**	**12,894**	**14,394**
Cumulative Total to:																				
Northeast Premium	330	330	330	663	663	663	663	663	663	663	663	808	808	808	808	2,383	2,383	2,383	2,383	2,383
MidAtlantic/South	1,344	1,344	1,344	3,319	3,319	3,319	3,945	4,195	4,195	4,579	4,579	4,579	6,629	8,029	10,729	16,929	16,929	16,929	16,929	18,429
MidCon/Canada	600	600	1,800	2,359	2,359	2,359	2,359	4,009	4,009	4,009	4,506	5,243	8,396	9,436	9,436	10,436	10,436	10,436	10,436	10,436
Total	**2,274**	**2,274**	**3,474**	**6,341**	**6,341**	**6,341**	**6,967**	**8,867**	**8,867**	**9,251**	**9,748**	**10,630**	**15,833**	**18,273**	**20,973**	**29,748**	**29,748**	**29,748**	**29,748**	**31,248**

Source: Morgan Stanley Commodities Research, "Natural Gas Marketing Guide," December 2016. Utilizes Company data, EIA, Bentek Energy and Morgan Stanley Commodities Research.

SCOOP Appendix

SCOOP – Type Curve Assumptions

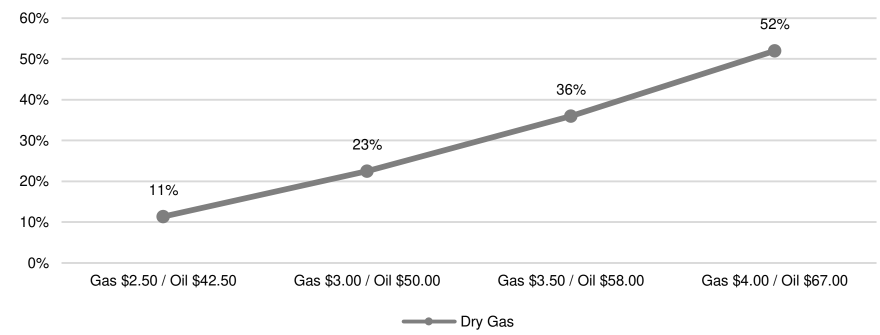
	Woodford Dry Gas		Woodford Wet Gas		Woodford Condensate	
Identified Gross Locations		**402**		**528**		**249**
Identified Net Locations		**65**		**182**		**33**
Type Curve Assumptions						
Lateral Length (ft.)		7,500		7,500		7,500
Wells/section		8		8		8
Initial Gas Production (Mcf/d)(1)		14,000		11,000		6,000
Shrink		-		13%		16%
NGL Yield (Bbls/MMcf)		-		31		75
Residue BTU		1,000		1,060		1,095
Pre-Processed EUR (Bcfe)		19.8		18.8		11.3
Pre-Processed % Gas		100%		92%		77%
Post-Processed EUR (Bcfe / 1,000')(2)		2.6		2.6		1.5
Post-Processed EUR (Bcfe)(2)		19.8		19.7		11.5
Oil (MBbl)		-		250		374
NGL (MBbl)		-		536		540
Residue Gas (MMcf)		19,800		15,021		6,048
Post Processed % Gas		100%		76%		52%
Unhedged Pricing(3)						
Gas ($ / MMBtu off NYMEX)	$	(0.45)	$	(0.45)	$	(0.45)
Condensate ($ / Bbl off WTI)	$	(6.00)	$	(6.00)	$	(6.00)
NGL (% of WTI)		35%		35%		35%
Operating Expenses						
OPEX – 3 Months						
Fixed ($/well/mo)	$	8,000	$	10,000	$	10,000
OPEX - Remaining						
Fixed ($/well/mo)	$	6,000	$	8,000	$	8,000
Variable ($/Mcf)	$	0.05	$	0.05	$	0.05
Gathering & Compression ($/Mcf)	$	0.41	$	0.49	$	0.52
Processing (% of Revenue)		-		1.5%		1.5%
Severance Tax – Years 1-3		2.2%		2.2%		2.2%
Years 4+		7.2%		7.2%		7.2%
Well Cost Assumptions						
Well Cost ($MM)	$	12.3	$	10.5	$	9.7
Well Cost ($ per foot)	$	1,633	$	1,395	$	1,295

1) Represents 24-hour rate well head gas production.
2) Assumes ethane rejection.
3) Includes transportation costs and basis differentials.

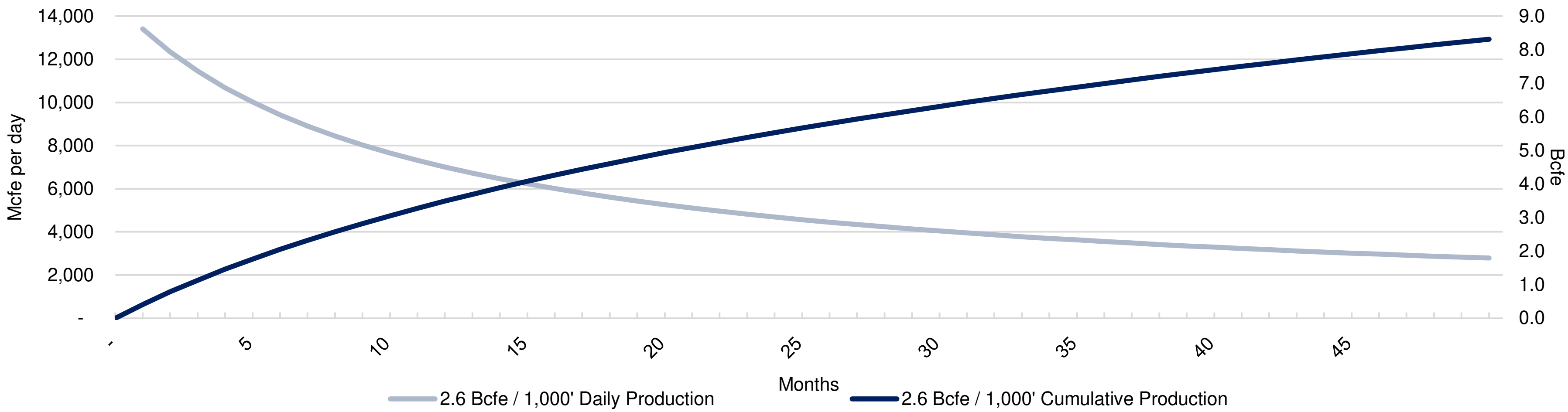
SCOOP – Dry Gas Window Type Curves

Type Curve Assumptions[1]	Dry Gas
Lateral Length	7,500
Well Cost ($MM)	$12.3
Well Cost ($ per foot)	$1,633
Total EUR (Bcfe / 1,000)	2.6
Total EUR (Bcfe)	19.8
% Gas	100%
Wells per section	8
Gross Undeveloped Locations	402
Net Undeveloped Locations	65

Single Well Economics[1]



Dry Gas Type Curves[1]

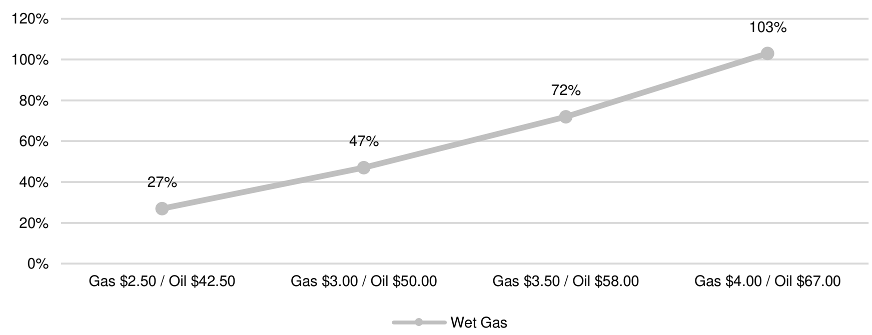


Note: See appendix slide 42 for detailed assumptions used to generate single well IRRs.
1) Assumes ethane rejection.

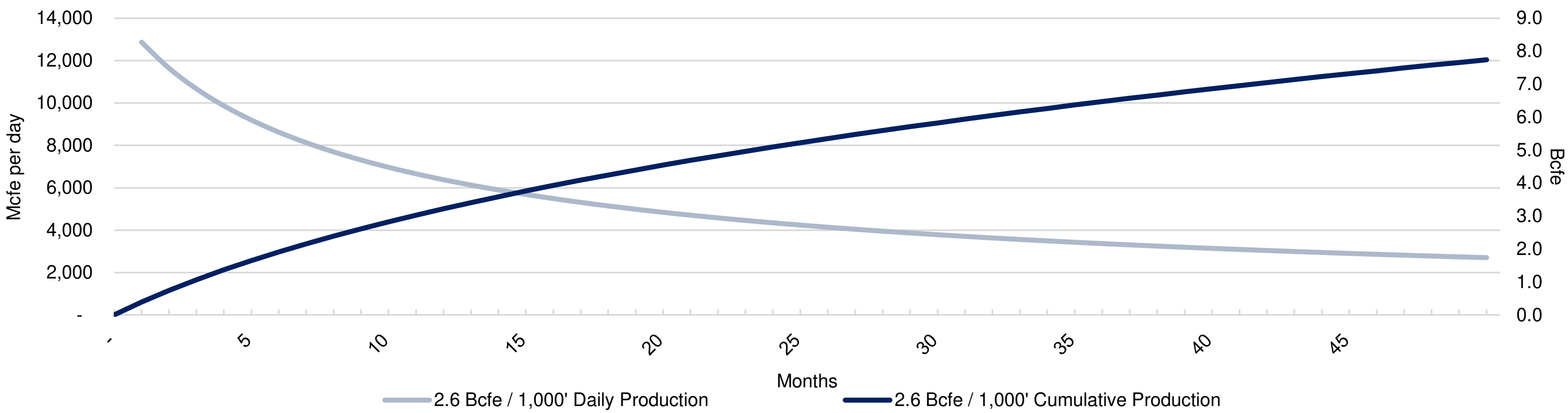
SCOOP – Wet Gas Window Type Curves

Type Curve Assumptions[1]	Wet Gas
Lateral Length	7,500
Well Cost ($MM)	$10.5
Well Cost ($ per foot)	$1,395
Total EUR (Bcfe / 1,000)	2.6
Total EUR (Bcfe)	19.7
% Gas	76%
Wells per section	8
Gross Undeveloped Locations	528
Net Undeveloped Locations	182

Single Well Economics[1]



Wet Gas Type Curves[1]

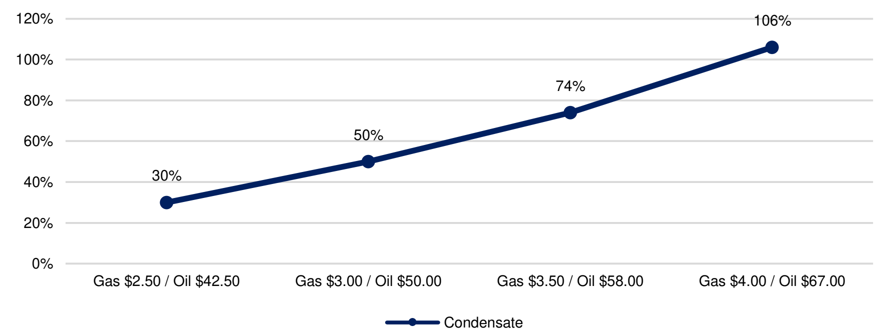


Note: See appendix slide 42 for detailed assumptions used to generate single well IRRs.
1) Assumes ethane rejection.

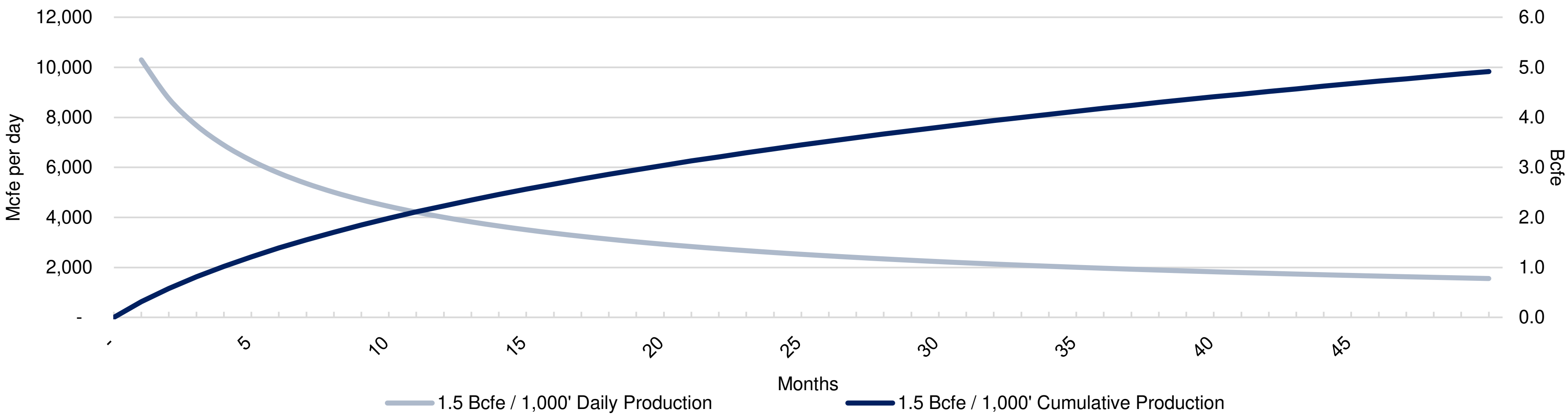
SCOOP – Condensate Window Type Curves

Type Curve Assumptions[1]	Condensate
Lateral Length	7,500
Well Cost ($MM)	$9.7
Well Cost ($ per foot)	$1,295
Total EUR (Bcfe / 1,000)	1.5
Total EUR (Bcfe)	11.5
% Gas	52%
Wells per section	8
Gross Undeveloped Locations	249
Net Undeveloped Locations	33

Single Well Economics[1]



Condensate Type Curves[1]



Note: See appendix slide 42 for detailed assumptions used to generate single well IRRs.

1) Assumes ethane rejection.

Appendix

Southern Louisiana

Asset Overview[1]

- Net proved reserves of 2.6 MMBoe
- 9,301 net acres
- Gulfport operated

2016 Activities Update[2]

- Average net production of 2,991 Boepd during 4Q2016
- ~2% of Gulfport's total net production
- ~99% oil weighted production mix
  - Priced as high quality LLS crude and sold at a premium to WTI

2017 Planned Activities[3]

- Gulfport plans to run one drilling rig and one recompletion rig in Southern Louisiana during 2017

Note: Please refer to page 2 for detail on forward looking statements.
1) As of 12/31/16.
2) During the three-month period ended 12/31/16.
3) As of 2/13/17.

Mammoth Energy Services

Mammoth Energy Overview[1]

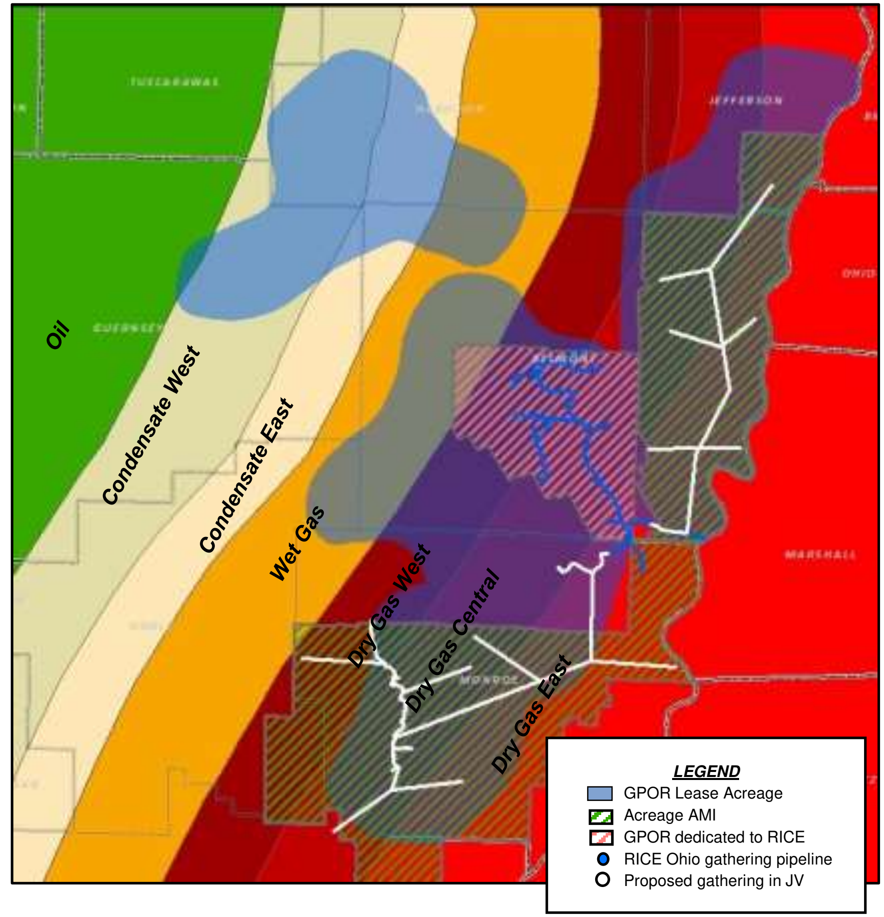
- **Mammoth Energy is a North American provider of diverse oil field services for the onshore unconventional oil and gas sector**
- **On October 19, 2016, Mammoth Energy completed its initial public offering and it now listed on the NASDAQ under ticker symbol "TUSK"**
  - Gulfport contributed its 30.5% equity interest at the time of the IPO
- **On March 20, 2017, Mammoth Energy announced the acquisition of Taylor Frac, Stingray Energy Services and Stingray Cementing, all entities in which Gulfport holds an equity interest**
  - Gulfport will receive ~2.1 million shares of TUSK shares at the time of the closing
- **Gulfport holds ~11.2 million[1] shares, equating to ~25.1% of TUSK's total shares outstanding**
- **Mammoth operates under four service divisions:**
  - Completion and production services:
  - Natural sand proppant services:
  - Contract land and directional drilling services:
  - Remote accommodation services:
- **Gulfport's ownership in Mammoth Energy equates to approximately ~ $225 million[1] in value**

Note: Gulfport Energy Corporation holds ~11.2 million shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK)., which includes ~2.1 million shares to be acquired upon closing of the previously announced pending acquisition of Taylor Frac, Stingray Energy Services and Stingray Cementing. Please refer to page 2 for detail on forward looking statements.
1) As of 3/23/17.
2) Calculated as of the close of the market on 3/23/17 at a price of $20.09 per share.

Strike Force Midstream Joint Venture

Overview

- **GPOR and RICE formed midstream JV, Strike Force Midstream LLC, to provide gas gathering, compression and water services to GPOR's Eastern Belmont and Monroe acreage**
  - Approximately 165 miles of high and low pressure 12" – 30" dry gas gathering pipeline to be constructed
  - Approximately 1.8 MMDth/d of estimated throughput capacity
- **Facilitates third party opportunities within ~320,000 acre AMI**
- **Ownership: GPOR 25% and RICE 75% with RICE to construct and operate all JV assets**
- **Creates enhanced alignment with midstream provider, providing certainty to timing of infrastructure buildout and further predictability to Gulfport's production profile**
- **Provides Gulfport with connectivity of our gathering systems and interchangeability of molecules across our firm portfolio**
- **Gulfport anticipates to spend $50 to $60 million on midstream activities within the JV area during 2017**



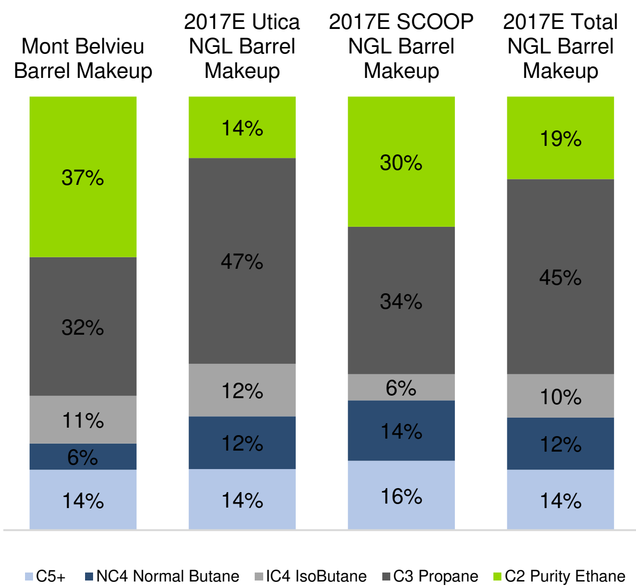
Participating in Extensive Dry Gas System in One of the Most Prolific Natural Gas Plays

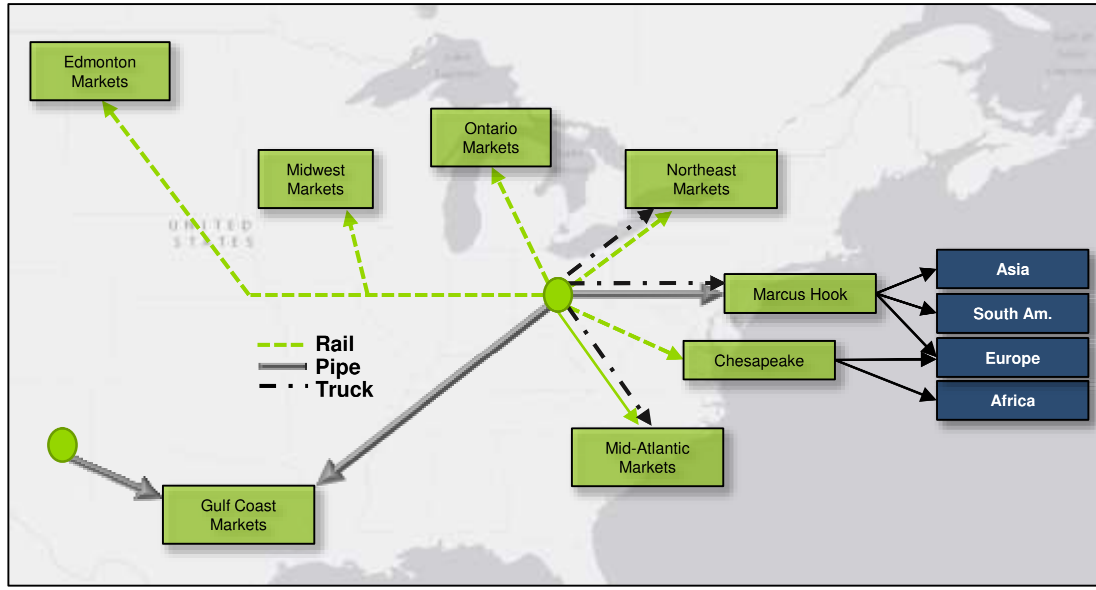
NGL Marketing Overview

Key Highlights

- **Gulfport forecasts realizing ~35% of WTI for NGLS during 2017**
- **SCOOP barrel provides a strong baseload with Mont Belvieu exposure, while Utica purity products provide clarity into market dynamics**
- **Increased access to pipe provides additional reliability to Gulfport's NGL distribution network**

NGL Barrel Composition





Markets	% of 2016 C3+ Bbl
Northeast	23%
Export	8%
Gulf Coast	53%
Edmonton	6%
Midwest	5%
Mid-Atlantic	3%
Ontario	2%
	100%

Transport Method	% of 2016 C3+ Bbl
By Rail	30 - 35%
By Pipeline	60 - 65%
By Truck	5 - 10%

Hedged Production

Hedge Book(1)

	1Q17	2Q17	3Q17	4Q17	2017	2018	2019
Natural Gas Contract Summary:							
Natural Gas Fixed Price Swaps (NYMEX)							
Volume (BBtupd)	487	527	568	635	555	384	5
Weighted Average Price ($/MMBtu)	$ 3.16	$ 3.22	$ 3.17	$ 3.17	$ 3.18	$ 3.12	$ 3.37
Natural Gas Fixed Price Swaptions (NYMEX) (2)							
Volume (BBtupd)	45	65	65	65	60	65	-
Weighted Average Price ($/MMBtu)	$ 3.19	$ 3.11	$ 3.11	$ 3.11	$ 3.12	$ 3.33	$ -
Total Potential Natural Gas Volumes (BBtupd)	532	592	633	700	615	449	5
Total Weighted Average Price ($/MMBtu)	$ 3.16	$ 3.21	$ 3.16	$ 3.16	$ 3.17	$ 3.15	$ 3.37
Basis Contract Summary:							
Tetco M2							
Volume (BBtupd)	50	-	-	-	12	-	-
Differential ($/MMBtu)	$ (0.59)	$ -	$ -	$ -	$ (0.59)	$ -	$ -
NGPL MidCon							
Volume (BBtupd)	-	50	50	50	38	12	-
Differential ($/MMBtu)	$ -	$ (0.26)	$ (0.26)	$ (0.26)	$ (0.26)	$ (0.26)	$ -
Oil Contract Summary:							
Oil Fixed Price Swaps (LLS)							
Volume (Bblpd)	2,000	2,000	1,500	1,500	1,748	-	-
Weighted Average Price ($/Bbl)	$ 51.10	$ 51.10	$ 53.12	$ 53.12	$ 51.97	$ -	$ -
Oil Fixed Price Swaps (WTI)							
Volume (Bblpd)	1,033	3,330	4,500	4,500	3,353	899	-
Weighted Average Price ($/Bbl)	$ 55.15	$ 55.18	$ 54.89	$ 54.89	$ 54.98	$ 55.31	$ -
Total Potential Crude Oil (Bblpd)	3,033	5,330	6,000	6,000	5,101	899	-
Total Weighted Average Price ($/Bbl)	$ 52.48	$ 53.65	$ 54.45	$ 54.45	$ 53.95	$ 55.31	$ -
NGL Contract Summary:							
C3 Propane Fixed Price Swaps							
Volume (Bblpd)	1,156	3,000	3,000	3,000	2,545	-	-
Weighted Average Price ($/Gal)	$ 0.66	$ 0.63	$ 0.63	$ 0.63	$ 0.64	$ -	$ -
C5+ Fixed Price Swaps							
Volume (Bblpd)	250	250	250	250	250	-	-
Weighted Average Price ($/Gal)	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ -	$ -

1) As of February 13, 2017.
2) Counterparty has option to call.

Financial and Operational Summary

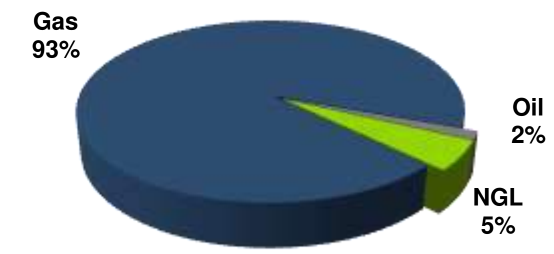
	2015 1Q2015	2Q2015	3Q2015	4Q2015	FY 2015	2016 1Q2016	2Q2016	3Q2016	4Q2016	FY 2016	Guidance FY2017E		4Q2016 Q-o-Q	Y-o-Y	2016 Y-o-Y
Production															
Gas - Bcf	26.0	33.1	48.1	48.9	156.2	53.3	52.8	58.2	63.4	227.6			9%	29%	46%
Oil - MBbls	765.6	727.1	732.1	674.6	2,899.4	601.8	551.5	521.4	451.2	2,125.9			(13%)	(33%)	(27%)
Liquids - MBbls	1,273.3	941.0	1,168.9	1,040.5	4,423.6	1,012.6	734.6	1,043.7	1,055.8	3,846.7			1%	1%	(13%)
Total Equivalent (Bcfe)	38.2	43.1	59.5	59.2	200.1	63.0	60.5	67.5	72.4	263.4			7%	22%	32%
Total Daily Equivalent (MMcfepd)	424,425	473,935	647,062	643,832	548,188	692,230	664,743	734,144	786,998	719,753	1,045,000	1,100,000	7%	22%	31%
Product Mix															
Gas	68%	77%	81%	83%	78%	85%	87%	86%	87%	86%	~88%				
Liquids	32%	23%	19%	17%	22%	15%	13%	14%	13%	14%	~8				
											~4				
Realized Prices															
Average Realized Prices before the impact of derivatives ($/Mcfe)	**$3.30**	**$2.84**	**$2.33**	**$2.00**	**$2.53**	**$1.58**	**$1.81**	**$2.35**	**$2.67**	**$2.13**			14%	34%	(16%)
Average Realized Prices incl. cash-settlement of derivatives ($/Mcfe)	**$3.30**	**$3.41**	**$2.83**	**$2.79**	**$3.13**	**$2.61**	**$2.82**	**$2.54**	**$2.80**	**$2.69**			10%	0%	(14%)
Average Realized Prices including derivatives ($/Mcfe)	**$4.61**	**$2.60**	**$3.87**	**$3.21**	**$3.54**	**$2.49**	**($0.47)**	**$2.87**	**$0.88**	**$1.46**					
Average NYMEX Henry Hub ($/MMBtu)	$2.98	$2.64	$2.77	$2.27	$2.66	$2.09	$1.95	$2.81	$2.99	$2.46					
Differential to Henry Hub ($/MMBtu)	(0.44)	(0.59)	(0.87)	(0.78)	(0.75)	(0.79)	(0.60)	(0.85)	(0.80)	(0.73)					
Natural Gas Realized Price before the impact of derivatives ($/MMBtu)	$2.54	$2.05	$1.90	$1.49	$1.91	$1.30	$1.35	$1.96	$2.19	$1.73					
BTU Upgrade (MMBtu / Scf)	0.23	0.18	0.17	0.13	0.17	0.09	0.09	0.14	0.15	0.12					
Natural Gas Realized Price before the impact of derivatives ($/Mcf)	$2.77	$2.23	$2.07	$1.62	$2.08	$1.39	$1.44	$2.10	$2.34	$1.85					
Differential to Henry Hub ($/Mcf)	*(0.21)*	*(0.41)*	*(0.70)*	*(0.65)*	*(0.58)*	*(0.70)*	*(0.51)*	*(0.71)*	*(0.65)*	*(0.61)*	($0.56)	($0.62)			
Impact of cash settled derivatives ($/Mcf)	0.67	0.74	0.55	0.86	0.71	1.10	1.09	0.20	0.15	0.60					
Natural Gas Realized Price incl. cash-settlement of derivatives ($/Mcf)	**$3.44**	**$2.97**	**$2.62**	**$2.48**	**$2.79**	**$2.49**	**$2.53**	**$2.31**	**$2.49**	**$2.45**			8%	0%	(12%)
Average NYMEX WTI ($/Bbl)	$48.57	$57.96	$46.44	$42.64	$48.88	$33.51	$45.60	$44.94	$49.33	$43.37					
Differential to WTI ($/Bbl)	(6.85)	(7.81)	(5.91)	(6.25)	(6.59)	(7.19)	(3.60)	(3.13)	(4.17)	(5.18)	($4.50)	($5.50)			
Oil Realized Price before the impact of derivatives ($/Mcf)	$41.72	$50.15	$40.53	$36.38	$42.29	$26.32	$42.00	$41.81	$45.15	$38.18					
Impact of cash settled derivatives ($/Mcf)	1.88	(0.01)	4.30	$6.62	3.12	10.54	6.49	1.62	0.22	5.11					
Oil Realized Price incl. cash-settlement of derivatives ($/Bbl)	**$43.59**	**$50.14**	**$44.84**	**$43.00**	**$45.41**	**$36.86**	**$48.49**	**$43.43**	**$45.37**	**$43.29**			4%	5%	(5%)
NGL Realized Price before the impact of derivatives ($/Gal)	$0.41	$0.30	$0.19	$0.34	$0.31	$0.22	$0.33	$0.33	$0.56	$0.37					
Impact of cash settled derivatives ($/Gal)	-	-	-	0.00	0.00	0.01	-	-	(0.01)	(0.01)					
NGL Realized Price incl. cash-settlement of derivatives ($/Gal)	**$0.41**	**$0.30**	**$0.19**	**$0.34**	**$0.31**	**$0.23**	**$0.33**	**$0.33**	**$0.55**	**$0.36**			64%	60%	16%
% WTI	***36%***	***22%***	***17%***	***34%***	***27%***	***29%***	***30%***	***31%***	***47%***	***35%***	~30%				
Operating Expenses per Mcfe															
Lease operating expense	$0.44	$0.39	$0.30	$0.30	$0.35	$0.26	$0.24	$0.26	$0.28	$0.26	$0.18	$0.23	7%	(9%)	(25%)
Production taxes	$0.11	$0.08	$0.06	$0.06	$0.07	$0.05	$0.05	$0.05	$0.05	$0.05	$0.08	$0.09	0%	(13%)	(32%)
Midstream gathering and processing	$0.66	$0.76	$0.71	$0.64	$0.69	$0.60	$0.65	$0.67	$0.60	$0.63	$0.55	$0.62	(11%)	(7%)	(9%)
Unit Operating Costs	**$1.22**	**$1.23**	**$1.06**	**$1.01**	**$1.11**	**$0.91**	**$0.94**	**$0.98**	**$0.93**	**$0.94**	**$0.81**	**$0.94**	(5%)	(8%)	(15%)
Revenues (in thousands)															
Gas sales	$118,570	$65,871	$179,215	$144,070	$507,726	$131,094	($57,860)	$155,185	$25,776	$254,195					
Oil and condensates sales	35,500	34,465	41,747	30,104	141,816	17,121	20,533	23,507	$14,625	75,786					
Liquid sales	22,007	11,958	9,431	16,052	59,448	8,746	9,168	15,000	$23,015	55,929					
Other income, net	240	(24)	176	93	485	2	7	(6)	(132)	(129)					
Total Revenue	$176,317	$112,270	$230,569	$190,319	$709,475	$156,963	($28,152)	$193,686	$63,284	$385,781					
Plus non-cash hedge (gain) loss	(31,324)	34,633	(62,182)	(24,798)	(83,671)	7,685	198,685	(22,357)	139,290	323,303					
Total Revenue excl. non-cash impact from derivatives	**$144,993**	**$146,903**	**$168,387**	**$165,521**	**$625,804**	**$164,648**	**$170,533**	**$171,329**	**$202,574**	**$709,084**			18%	22%	13%
Expenses (in thousands)															
Lease operating expense	$16,980	$16,863	$17,568	$18,064	$69,475	$16,657	$14,661	$17,471	$20,088	$68,877			15%	11%	(1%)
Production taxes	4,285	3,285	3,593	3,577	14,740	3,111	2,856	3,525	3,784	13,276			7%	6%	(10%)
Midstream gathering and processing	25,381	32,904	42,166	38,139	138,590	37,652	39,349	45,475	43,496	165,972			(4%)	14%	20%
General and administrative	10,799	9,515	11,001	10,652	41,967	10,620	11,854	10,467	10,468	43,409			0%	(2%)	3%
Other	(9)	(248)	(279)	(107)	(643)	(94)	(391)	(337)	(408)	(1,230)			21%	281%	91%
Adjusted EBITDA	**$87,557**	**$84,584**	**$94,338**	**$95,196**	**$361,675**	**$96,702**	**$102,204**	**$94,728**	**$125,146**	**$418,780**			32%	31%	16%
Depreciation, depletion and amortization	89,909	71,155	90,329	86,301	337,694	65,477	55,652	62,285	62,560	245,974			0%	(28%)	(27%)
Adjusted Net Income (Loss)	**($7,187)**	**$250**	**($8,694)**	**($609)**	**($16,240)**	**$15,146**	**$30,366**	**$20,018**	**$44,253**	**$109,783**					

2016 Proved Reserve Summary

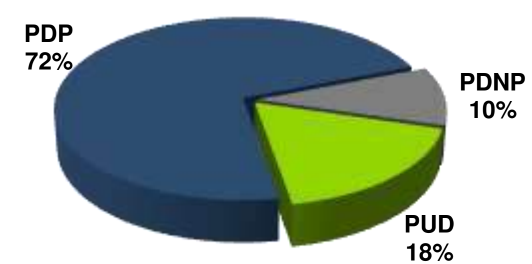
Net Reserves as of December 31, 2016[1]	Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)	PV-10 ($MM) SEC
Proved Developed Producing	678.3	3.8	13.5	781.8	$501
Proved Developed Non-Producing	66.5	1.1	0.8	78.1	$72
Proved Undeveloped	1,422.3	0.6	5.8	1,461.2	$123
Total Proved Reserves	2,167.1	5.5	20.1	2,321.1	$696

SEC Net Proved Reserves

SEC Proved Reserve Allocation



SEC 1P Net Present Value – 10%



1) Per Company reserve report for year ending 12/31/16.

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