INVESTOR PRESENTATION

AUGUST 2018

FORWARD LOOKING STATEMENT

This presentation includes "forward-looking statements" for purposes of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of 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, 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 that might affect the timing and amount of the repurchase program; 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 presentation 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, 2017 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to Gulfport's assets in the Utica Shale of Eastern Ohio, Gulfport's SCOOP Woodford assets in Oklahoma 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, 2017), 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 income, the most directly comparable GAAP financial measure, plus interest expense, income tax (benefit) expense, accretion expense and depreciation, depletion and amortization. Adjusted EBITDA is a non-GAAP financial measure equal to EBITDA less non-cash derivative loss (gain), acquisition expense and (income) 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 income less non-cash derivative loss (gain), acquisition expense and (income) 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

Utica Shale
Acreage: ~215,000 Net Acres
YE 2017 Proved Reserves: 3.9 Net Tcfe
2Q2018 Net Production: 1,065.9 MMcfepd

SCOOP
Acreage: ~92,500 Net Reservoir Acres
YE 2017 Proved Reserves: 1.5 Net Tcfe
2Q2018 Net Production: 247.3 MMcfepd

KEY STATISTICS

Market Capitalization[1]	**$2.0 Billion**
Enterprise Value[2]	**$4.0 Billion**
Pro Forma Liquidity[3]	**~$787 Million**
2017 Average Daily Production	**1,089.2 MMcfepd**
1Q17	849.6 MMcfepd
2Q17	1,038.4 MMcfepd
3Q17	1,199.6 MMcfepd
4Q17	1,263.3 MMcfepd
2018E Average Daily Production	**1,320 – 1,340 MMcfepd**
1Q18	1,288.6 MMcfepd
2Q18	1,330.3 MMcfepd
Net Core Acreage	
Utica Shale	~215,000 acres
SCOOP[4]	~92,500 acres
Identified Gross Locations	
Utica Shale[5]	~1,200 gross locations
SCOOP	~1,950 gross locations

1. Market capitalization calculated as of the close of the market on 7/31/18 at a price of $11.51 per diluted share using shares outstanding from the Company's 2Q2018 financial statements.
2. Enterprise value calculated as of the close of the market on 7/31/18 at a price of $11.51 per diluted share using shares outstanding, short-term debt, long-term debt, and cash and cash equivalents from the Company's 2Q2018 financial statements.
3. Liquidity calculated as of 6/30/18 using borrowing base availability, letters of credit outstanding, cash and cash equivalents from the Company's 2Q2018 financial statements.
4. SCOOP acreage includes ~50,200 Woodford and ~42,300 Springer net reservoir acres.
5. Assumes net undeveloped locations grossed up from 75% working interest.

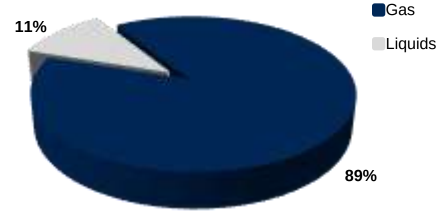
SECOND QUARTER 2018 HIGHLIGHTS

DAILY NET PRODUCTION

Increased
28% Y-o-Y

Produced
~1,330.3
MMcfe
per day
during 2Q2018

PRODUCTION MIX



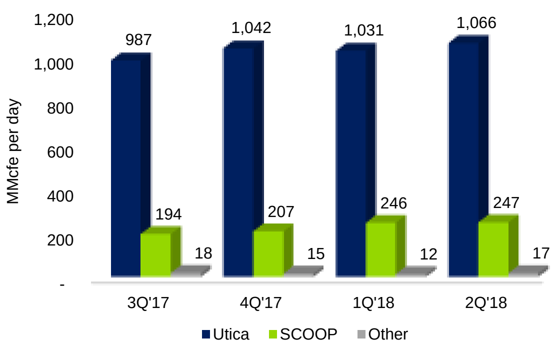
Production mix consisted of
89% gas and 11% liquids
during 2Q2018

ADJUSTED EBITDA

Increased
28% Y-o-Y

Totaled
Approximately
$213.6 million[(1)]
during 2Q2018

DAILY NET PRODUCTION BY ASSET



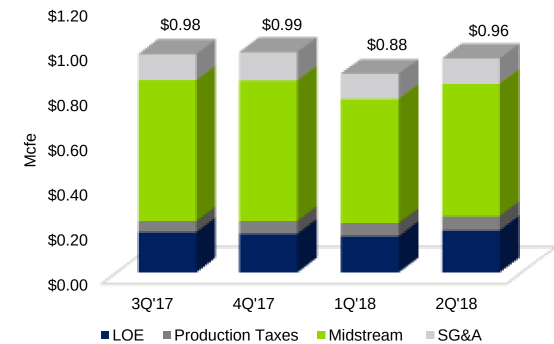
Production consisted of ~80% Utica,
~19% SCOOP and ~1% Other
during 2Q2018

STOCK REPURCHASE PROGRAM

Reduced shares
outstanding by
approximately 5%

Repurchased
$110 million[(2)] of
outstanding stock,
totaling ~10.5
million shares at
an average price
of $10.47

PER UNIT OPERATING EXPENSE



Per unit operating expense
totaled $0.96 per Mcfe
during 2Q2018

1. Adjusted EBITDA excludes the impact of the Company's non-cash derivative loss, insurance proceeds and income from equity method investments during the second quarter of 2018.
2. As of August 1, 2018.

UPDATE ON 2018 STRATEGY AND OPERATIONAL PLANS

2018 INITIATIVES	SECOND QUARTER 2018 UPDATE
PRACTICE STRICT CAPITAL DISCIPLINE AND FUND 2018 CAPITAL PROGRAM ENTIRELY WITHIN CASH FLOW	— Reaffirmed 2018 D&C capital expenditures of \$630 million to \$685 million and non-D&C capital expenditures of \$120 million to \$130 million — Reiterated full-year 2018 total capital program will be funded entirely within cash flow — Reached a pivotal point in the 2018 program, achieving free cash flow generation beginning in the third quarter of 2018
DELIVER STRONG ANNUAL PRODUCTION GROWTH WITHIN CASH FLOW	— 2Q2018 production averaged 1.33 Bcfepd, an increase of ~3% over first quarter 2018 and 28% year-over-year — Driven by the outperformance year-to-date, increased full-year 2018 production guidance to 1.32 to 1.34 Bcfepd, an increase of approximately 21% to 23% over full-year 2017
MAINTAIN A STRONG BALANCE SHEET AND FINANCIAL POSITION	— As of June 30, 2018, net-debt-to-EBITDA ratio decreased to 2.3 times, or below 2 times when adjusted for Gulfport's ownership in Mammoth Energy — Completed sale of 25% equity interest in Strike Force Midstream for a total of \$175 million and monetized a portion of Gulfport's shares held in Mammoth Energy for proceeds of ~\$50 million during 2Q208 — Large hedge position providing certainty of cash flows totaling 948 BBtu per day at \$3.05 in 2018 and 1,154 BBtu per day at \$2.81 in 2019
RETURN CASH TO SHAREHOLDERS THROUGH SHARE REPURCHASE PROGRAM	— Repurchased \$110 million of Gulfport's outstanding common stock as of August 1st, 2018, reducing shares outstanding by ~5% — Authorized to acquire up to \$200 million of outstanding common stock during 2018 and approximately \$90 million remains under the current authorization — Will continue to consider all options, including additional share repurchases and debt reduction, remaining disciplined and demonstrating the Company's commitment to shareholders with every dollar invested

GULFPORT 2018 GUIDANCE

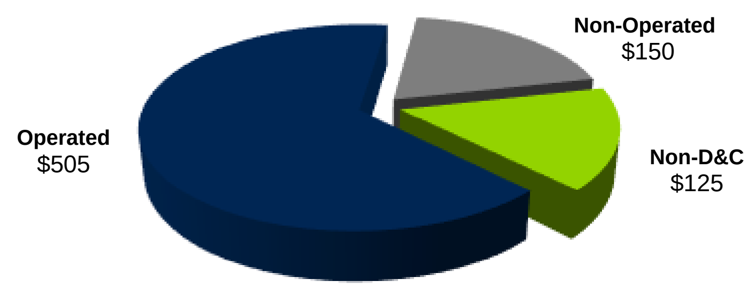
2018E CAPITAL BUDGET

	Year Ending 12/31/2018	
Forecasted Production		
Average Daily Gas Equivalent – MMcfepd	1,320	1,340
% Gas	~89%	
% NGLs	~7%	
% Oil	~4%	
Forecasted Realizations (before the effects of hedges)[1]		
Natural Gas (Differential to NYMEX) - $ per Mcf	($0.58)	($0.72)
NGL (% of WTI)	45%	50%
Oil (Differential to NYMEX WTI) - $ per Bbl	($3.00)	($3.50)
Projected Operating Costs		
Lease Operating Expense - $/Mcfe	$0.17	$0.19
Production Taxes - $/Mcfe	$0.06	$0.08
Midstream Gathering and Processing - $/Mcfe	$0.57	$0.63
General and Administrative[2] - $/Mcfe	$0.12	$0.14
Depreciation, Depletion, and Amortization - $/Mcfe	$0.95	$1.05
Budgeted D&C Capital Expenditures – in Millions:		
Operated	$490	$525
Non-Operated	$140	$160
Total Budgeted D&C Capital Expenditures	$630	$685
Budgeted Non-D&C Capital Expenditures – in Millions:	$120	$130
Total Budgeted Capital Expenditures – in Millions:	$750	$815

2018E FORECASTED ACTIVITY

	Year Ending 12/31/2018	
Net Wells Drilled		
Utica – Operated	26	29
Utica – Non – Operated	7	8
Total	33	37
SCOOP – Operated	10	11
SCOOP – Non - Operated	4	5
Total	14	16
Net Wells Turned-to-Sales		
Utica – Operated	33	37
Utica – Non - Operated	9	10
Total	42	47
SCOOP – Operated	16	18
SCOOP – Non - Operated	2	3
Total	18	21

2018E CAPEX (IN MILLIONS)[3]



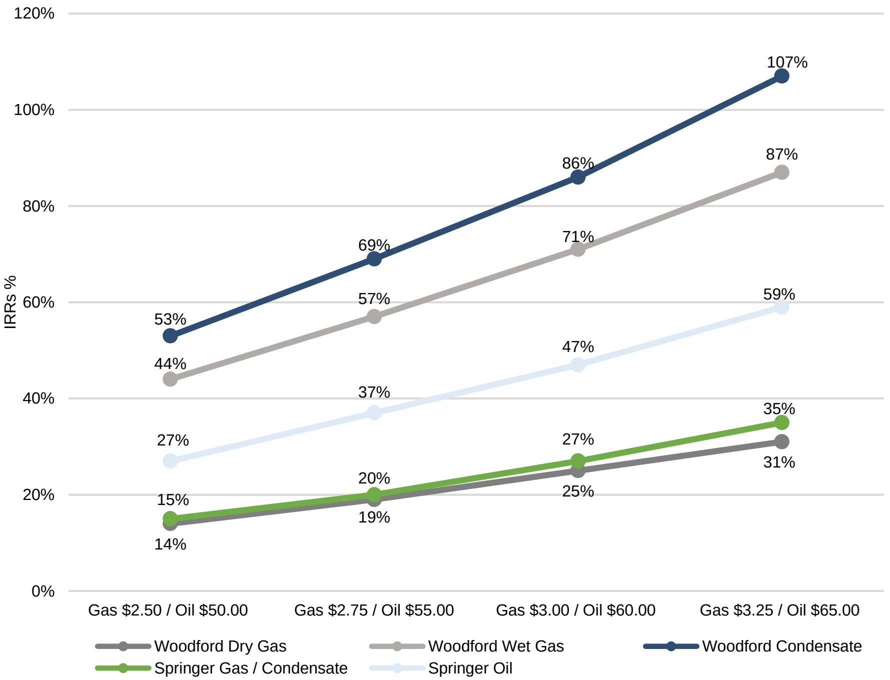
1. Based upon current forward pricing and basis marks.
2. Includes non-cash stock compensation.
3. Based on midpoint of 2018 guidance.

Note: Guidance for the year ending 12/31/18 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.

2018 ACTIVITY ECONOMIC FOCUS

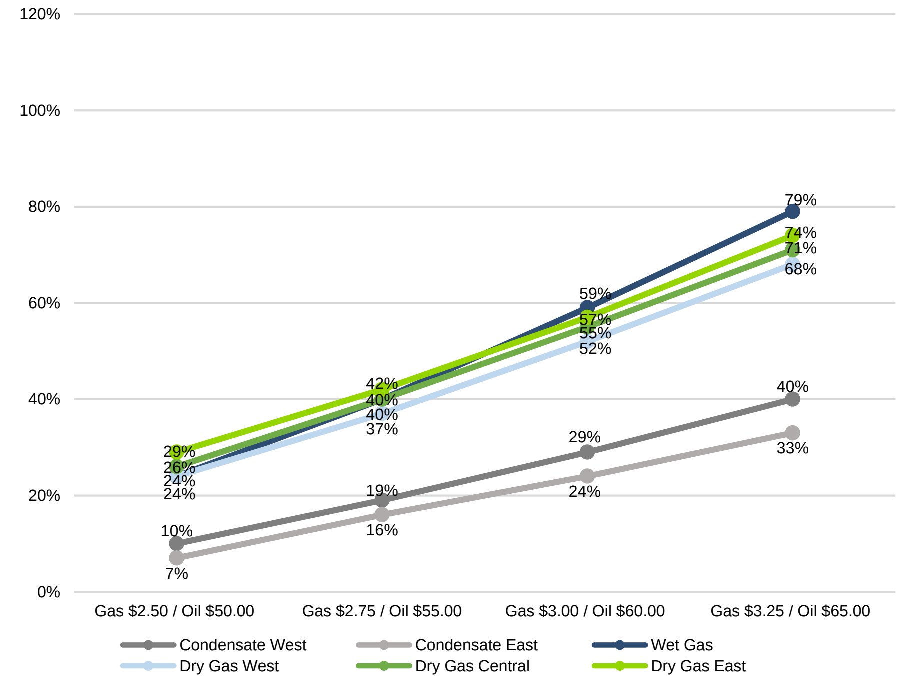
- Plan to focus Utica Shale activity in the dry gas windows and SCOOP activity in the wet gas window of the play
- Allocation of capital split between two top-tier basins with dry gas and liquids inventory

SCOOP SINGLE WELL ECONOMICS[1,2]



	Woodford Dry Gas	Woodford Wet Gas	Woodford Condensate	Springer Gas Condensate	Springer Oil
Gross Undeveloped Locations	444	642	350	238	300
Net Undeveloped Locations	84	230	30	82	64

UTICA SINGLE WELL ECONOMICS[1,2]

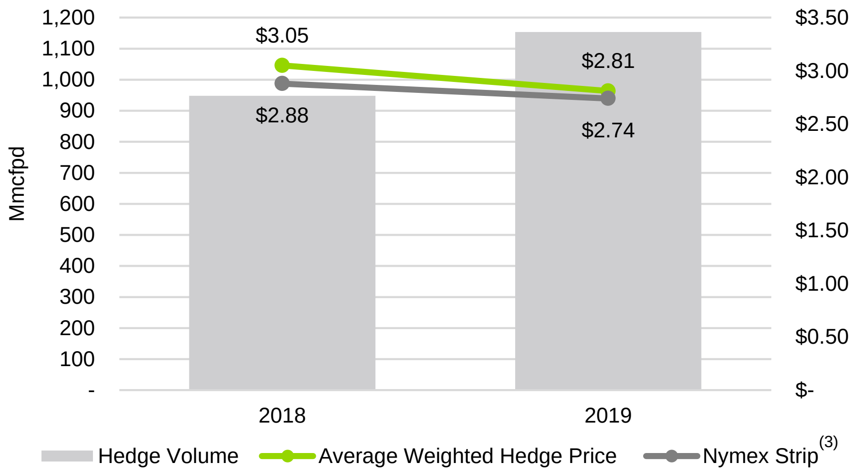


	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Gross Undeveloped Locations[3]	129	73	114	181	441	259
Net Undeveloped Locations	97	54	86	135	331	194

1. Assumes ethane rejection.
2. Well economics are adjusted for transport fees and regional price differentials.
3. Assumes net undeveloped locations grossed up from 75% working interest.

STRONG LIQUIDITY, CAPITALIZATION AND HEDGE POSITION

GAS HEDGES[1]



KEY HIGHLIGHTS

— In 2018, Gulfport is committed to a disciplined capital program within cash flow for the calendar year

- At strip pricing[2], Gulfport forecasts full-year 2018 total capital program to be funded within cash flow while growing production approximately 21% to 23% in 2018 over 2017

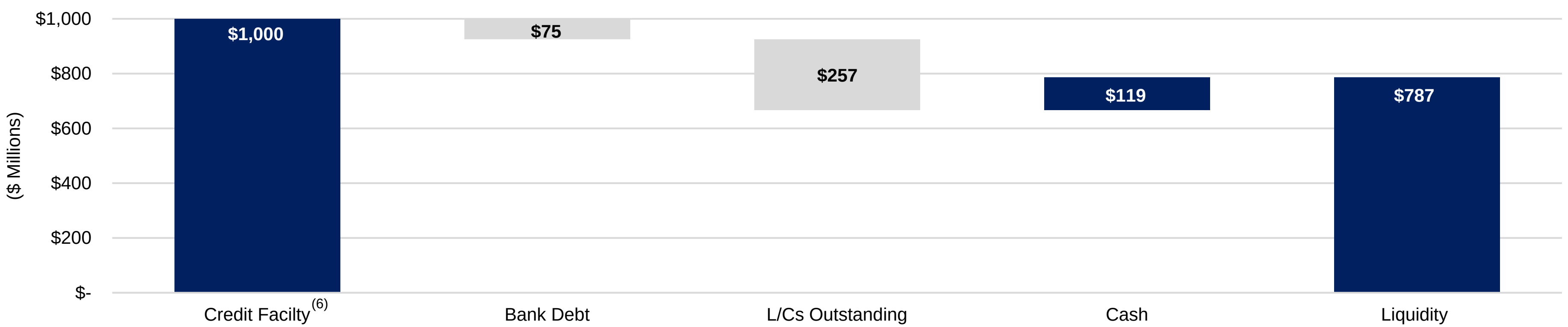
— Gulfport's hedge portfolio underpins its capital program, providing a high degree of certainty surrounding the Company's cash flow profile

- ~80%[5] of expected natural gas production hedged in 2018, totaling 948 BBtu per day at $3.05 per MMBtu
- Large base load of natural gas production hedged in 2019, totaling 1,154 BBtu per day at $2.81 per MMBtu

— As of June 30, 2018, Gulfport's net-debt-to-TTM-EBITDA ratio decreased to 2.3x, or below 2x when adjusted for Gulfport's ownership in Mammoth Energy

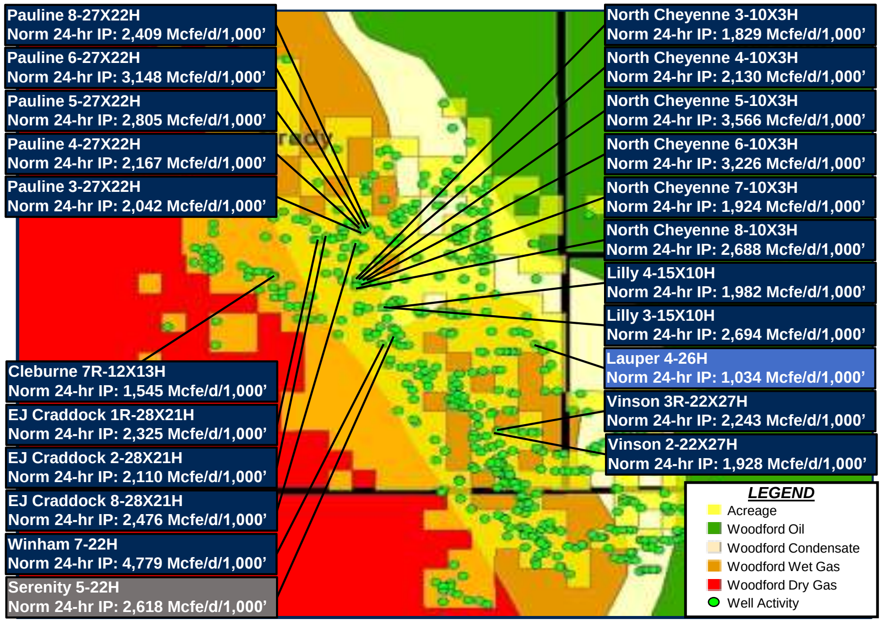
- Gulfport holds a ~22% interest in Mammoth Energy Services, totaling ~9.8 million shares valued at ~$350 million[7]

LIQUIDITY POSITION[4]



1. Hedge volume and weighted average price excludes swaptions. Detailed overview in appendix of the presentation.
2. Price forecast as of 8/1/18.
3. Price forecast as of 7/31/18.
4. Liquidity calculated as of 6/30/18 using borrowing base availability, letters of credit outstanding, cash and cash equivalents from the Company's 2Q2018 financial statements.
5. Based on the midpoint of 2018 guidance.
6. The Company's borrowing base totals $1.4 billion with elected commitments of $1.0 billion.
7. Gulfport holds ~9.8 million shares of Mammoth Energy Services and calculated as of the close of the market on 7/31/18 at a price of $37.22 per share.

SCOOP – RECENT GULFPORT WELL RESULTS



Woodford
Springer
Sycamore

OVERVIEW

— Gulfport has provided initial production rates on a number of Woodford wells in the play and continues to be pleased with the well performance seen to date

 – Gulfport’s Woodford wells continue to outperform on average relative to their offsets and type curves

— During 2017, Gulfport tested both the Springer and Sycamore zones on its acreage

— During 2018, Gulfport will be largely focused on the liquids-rich, wet gas area of the play

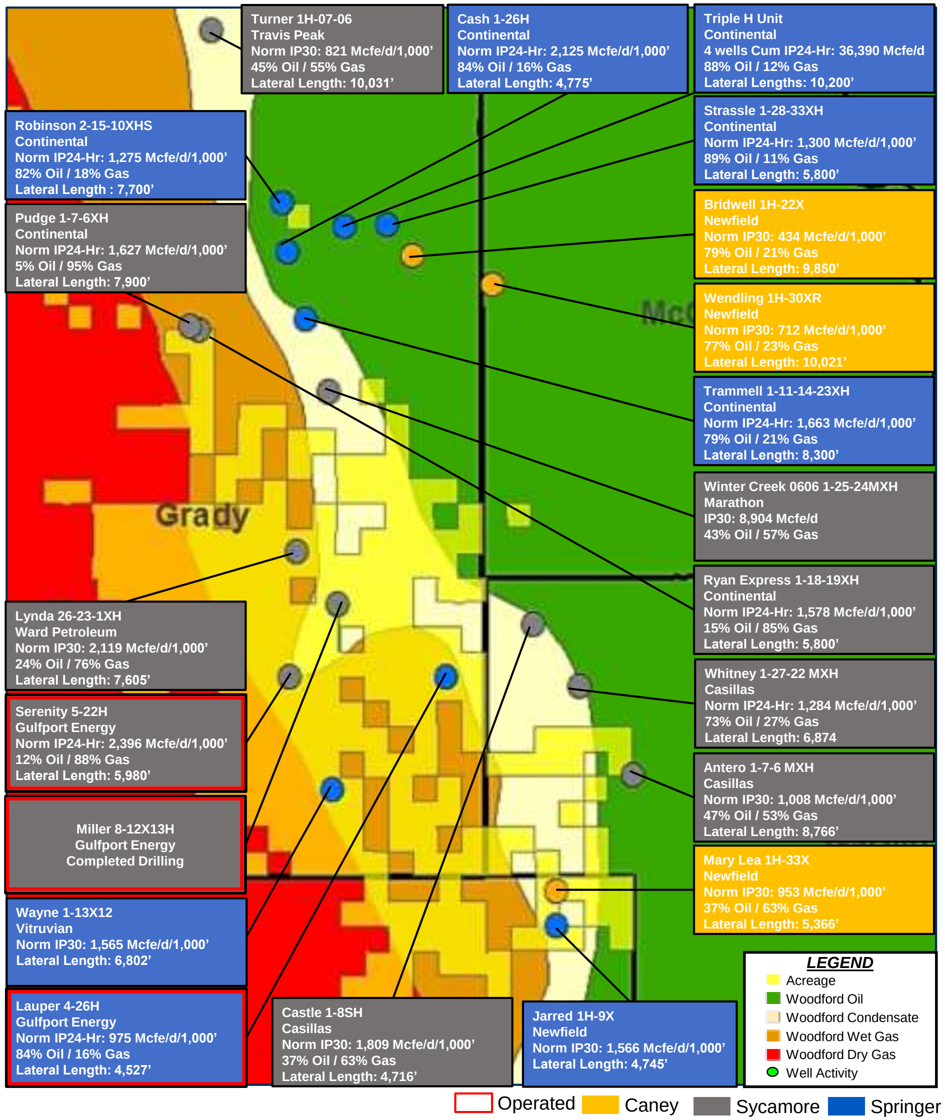
Recent Well Results Summary

	County	Phase Window	Stimulated Lateral	Wellhead BTU	NGLs Per MMcf	% Shrink	Product Mix[1] Gas	Product Mix[1] NGLs	Product Mix[1] Oil	Average Prod. Rates (MMcfepd) 24-Hr	30-Day	60-Day	90-Day
EJ Craddock 1R-28X21H	Central Grady	Woodford Wet Gas	9,008	1,133	36.9	12%	70%	18%	12%	20.9	n/a	n/a	n/a
EJ Craddock 2-28X21H	Central Grady	Woodford Wet Gas	9,939	1,133	36.9	12%	69%	17%	14%	21.0	n/a	n/a	n/a
EJ Craddock 8-28X21H	Central Grady	Woodford Wet Gas	7,961	1,171	47.0	16%	55%	19%	26%	19.7	17.3	16.1	15.2
Lilly 3-15X10H	Central Grady	Woodford Wet Gas	6,816	1,157	43.3	14%	66%	20%	14%	18.4	16.7	15.7	n/a
Lilly 4-15X10H	Central Grady	Woodford Wet Gas	7,323	1,157	43.3	14%	63%	19%	18%	14.5	13.1	12.4	n/a
North Cheyenne 3-10X3H	Central Grady	Woodford Wet Gas	7,218	1,162	44.1	15%	64%	20%	16%	13.2	12.1	11.3	10.6
North Cheyenne 4-10X3H	Central Grady	Woodford Wet Gas	6,867	1,162	44.1	15%	62%	19%	19%	14.6	13.4	12.6	11.9
North Cheyenne 5-10X3H	Central Grady	Woodford Wet Gas	5,782	1,152	41.7	14%	64%	19%	17%	20.6	18.4	16.9	15.9
North Cheyenne 6-10X3H	Central Grady	Woodford Wet Gas	6,002	1,152	41.7	14%	64%	19%	17%	19.4	16.8	15.3	14.1
North Cheyenne 7-10X3H	Central Grady	Woodford Wet Gas	6,379	1,162	43.9	15%	63%	20%	17%	12.3	12.7	12.1	11.5
North Cheyenne 8-10X3H	Central Grady	Woodford Wet Gas	6,413	1,162	43.9	15%	62%	19%	18%	17.2	16.1	15.2	14.2
Pauline 3-27X22H	Central Grady	Woodford Wet Gas	4,322	1,212	57.3	18%	49%	21%	30%	8.8	8.0	7.4	6.8
Pauline 4-27X22H	Central Grady	Woodford Wet Gas	7,978	1,212	57.3	18%	52%	22%	26%	17.3	16.1	15.0	14.1
Pauline 5-27X22H	Central Grady	Woodford Wet Gas	7,929	1,216	57.4	22%	50%	22%	27%	22.2	19.1	17.4	16.0
Pauline 6-27X22H	Central Grady	Woodford Wet Gas	7,273	1,216	57.4	22%	50%	22%	28%	22.9	19.6	17.7	16.2
Pauline 8-27X22H	Central Grady	Woodford Wet Gas	7,658	1,210	58.8	19%	51%	22%	27%	18.4	18.6	17.6	16.6
Vinson 2-22X27H	SE Grady	Woodford Wet Gas	8,539	1,118	35.7	11%	79%	19%	2%	16.5	15.7	14.4	13.4
Vinson 3R-22X27H	SE Grady	Woodford Wet Gas	8,475	1,118	35.7	11%	79%	19%	2%	19.0	18.7	17.3	16.3
Winham 7-22H	S Grady	Woodford Wet Gas	4,898	1,146	40.0	13%	64%	18%	18%	23.4	19.9	19.0	17.9
Cleburne 7R-12X13H	W Grady	Woodford Dry Gas	9,386	-	-	-	100%	-	-	14.5	13.1	n/a	n/a
Serenity 5-22H	S Grady	Sycamore	5,980	1,143	39.2	13%	70%	19%	11%	15.7	15.8	15.4	15.0
Lauper 4-26H	SE Grady	Springer Oil	4,527	1,418	120.8	34%	10%	11%	79%	4.7	3.2	2.9	2.6

Note: All well results presented on this slide are based upon three-stream production data and assume contractual ethane recovery.

1. Product mix calculated utilizing 24-hr initial production rate.

SCOOP – UPSIDE POTENTIAL IN EMERGING ZONES



OVERVIEW

- The Sycamore formation is age equivalent to the Meramec and Osage being developed in the STACK and is located between the organic-rich Woodford and Caney Shales
  - ~250 feet thick across the acreage position, presenting a significant future development target
  - Encouraged by the recent activity near Gulfport’s acreage position
  - Gulfport holds in excess of ~40,000 net reservoir acres prospective in the Sycamore
- The Caney Formation is Maramecian in age and is the stratigraphic equivalent of the Barnett Shale that has been developed in the Fort Worth Basin
  - Organic rich black shale with a high source rock potential
  - ~100 feet thick across the acreage position and directly overlies the Sycamore Formation
  - Highly productive wells in the southern Ardmore basin
- The Springer formation is an organic rich shale interval that has thus far been predominately oil productive
  - Strata contains several laterally extensive siliceous black shales that possess highly connected organic pores
  - Recent results have shown strong production and suggest high repeatability
  - Gulfport holds ~42,300 net reservoir acres in the Springer
- During 2017, Gulfport tested both the Springer and Sycamore zones on its acreage
- During the second quarter of 2018, Gulfport spud one Sycamore well, targeting the upper portion of the Sycamore formation
  - Gulfport recently completed drilling the well and plans to complete this well during the third quarter of 2018

Source: Company provided data and publicly available information. All well results presented on this slide are based upon two-stream production data.

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 50%[1]
- Significant exposure to the core of the Utica Shale with approximately 215,000 net acres under lease
  - Development expected to provide further catalyst for reserves and production growth
- Low-risk, highly contiguous SCOOP acreage with approximately 92,500[2] net reservoir 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 & HEDGE POSITION

- Committed to maintaining a strong balance sheet and financial discipline in 2018 and beyond
  - Liquidity of ~$787 million[3]
  - As of June 30, 2018, Gulfport's net-debt-to-EBITDA ratio decreased to 2.3x, or below 2x when adjusted for Gulfport's ownership in Mammoth Energy
  - Gulfport holds a ~22% interest in Mammoth Energy Services, totaling ~9.8 million shares valued at ~$350 million[4]
- 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
  - Gulfport has ~80%[5] of 2018E natural gas production hedged, totaling 948 BBtu per day at $3.05 per MMBtu and a large portion of its 2019E natural gas production hedged, totaling 1,154 BBtu per day at $2.81 per MMBtu
  - Company has historically targeted hedging 50% to 70% of expected twelve-month run rate total production

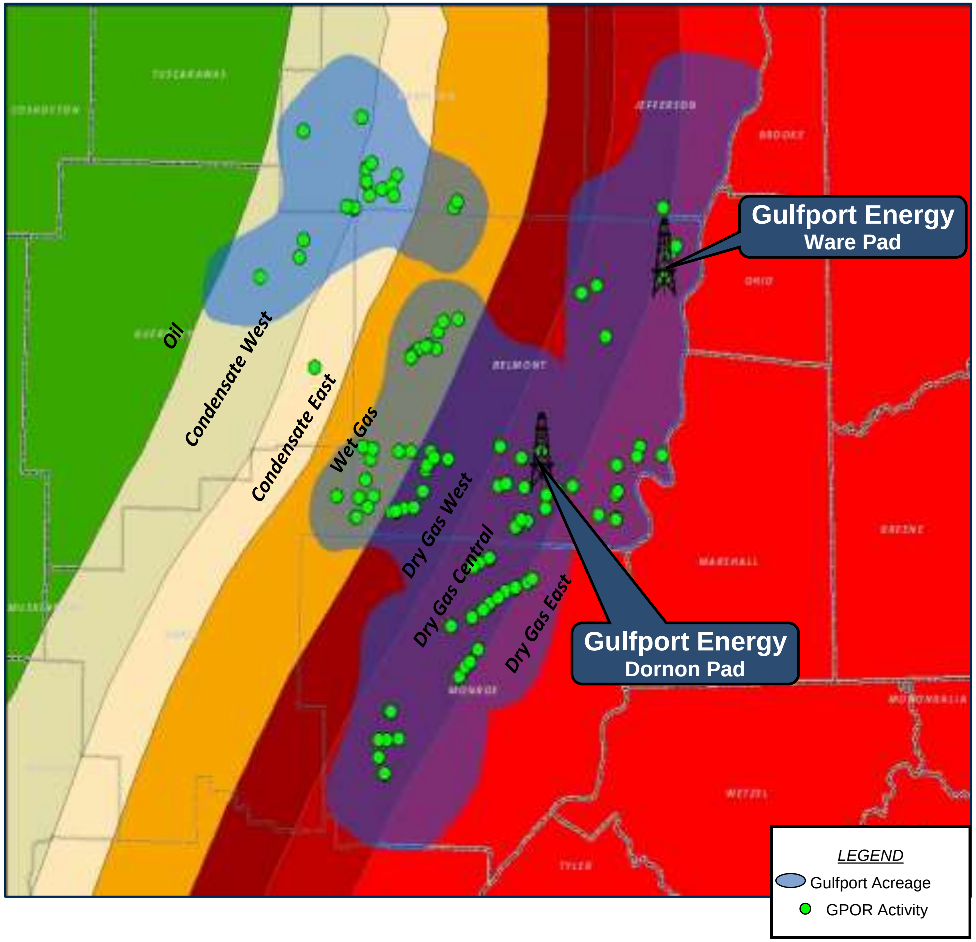
FOCUSED ON MAXIMIZING SHAREHOLDER VALUE

- In 2018, Gulfport is dedicated to strict capital discipline and is in the position to be able to generate free cash flow for its shareholders while also providing strong production growth
  - Based on current strip pricing[6], Gulfport forecasts its full-year 2018 total capital program to be funded entirely within cash flow while growing production approximately 21% to 23% over 2017
  - Gulfport has reached a pivotal point in the 2018 program, achieving free cash flow generation beginning in the third quarter of 2018
- Gulfport has repurchased $110[7] million of its outstanding common stock in the open market, totaling approximately 10.5 million shares
  - Gulfport intends to opportunistically repurchase its common stock during 2018 and will utilize available liquidity, including forecasted free cash flow generated and potential proceeds from the sale of certain investments
  - Gulfport is authorized to acquire up to $200 million of its outstanding common stock during 2018 and approximately $90 million remains under the current authorization

1. Well economics assume a flat price case of $3.00 / MMBtu gas, $60.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
2. SCOOP acreage includes ~50,200 Woodford and ~42,300 Springer net reservoir acres.
3. Liquidity calculated as of 6/30/18 using borrowing base availability, letters of credit outstanding, cash and cash equivalents from the Company's 2Q2018 financial statements.
4. Gulfport holds ~9.8 million shares of Mammoth Energy Services and calculated as of the close of the market on 7/31/18 at a price of $37.22 per share.
5. Based on the midpoint of 2018 guidance.
6. Price forecast as of 8/1/18.
7. As of August 1, 2018.

UTICA ASSET OVERVIEW

UTICA SHALE OVERVIEW



ASSET OVERVIEW

- Net proved reserves of 3.9 Tcfe[1]
- ~215,000 net acres
  - Oil - ~1%
  - Condensate - ~10%
  - Wet Gas - ~13%
  - Dry Gas - ~76%

2018 ACTIVITIES UPDATE[2]

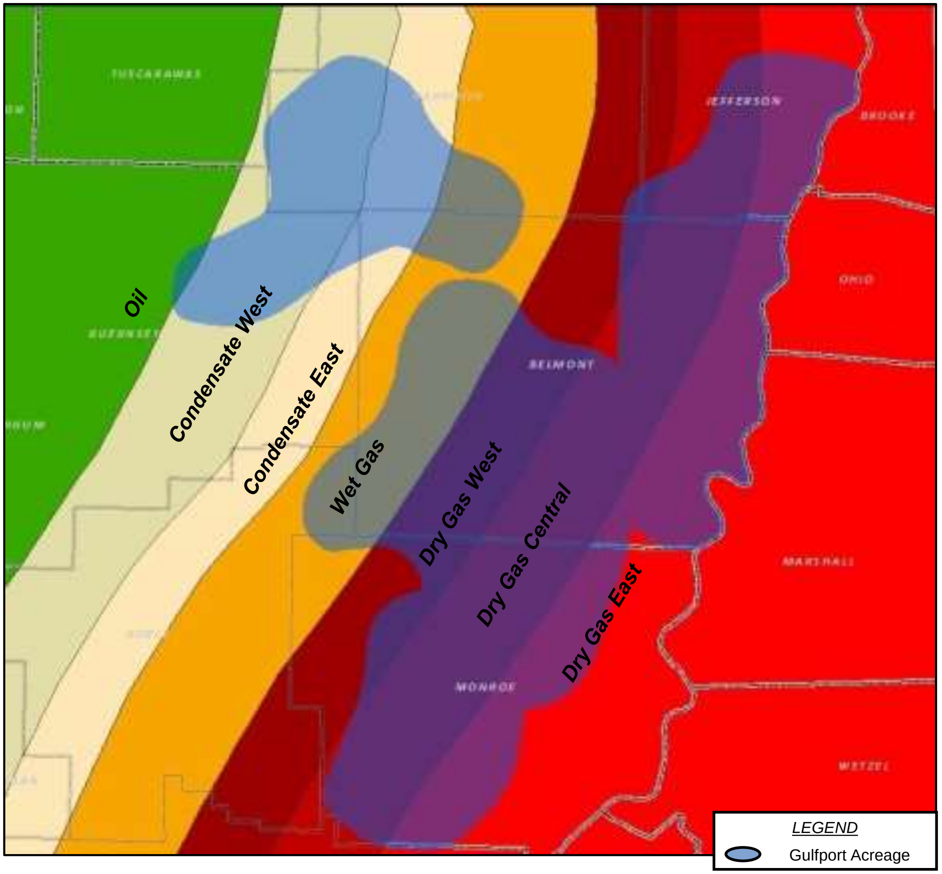
- Average net production of 1,065.9 MMcfepd
- ~80% of Gulfport's total net production

2018 PLANNED ACTIVITIES[3]

- Currently running 2 gross operated rigs
- Operated Activity
  - Drill 36 to 40 gross (26 to 29 net) wells
  - Turn-to-sales 33 to 37 gross (33 to 37 net) wells
- Non-Operated Activity
  - Drill 7 to 8 net wells
  - Turn-to-sales 9 to 10 net wells

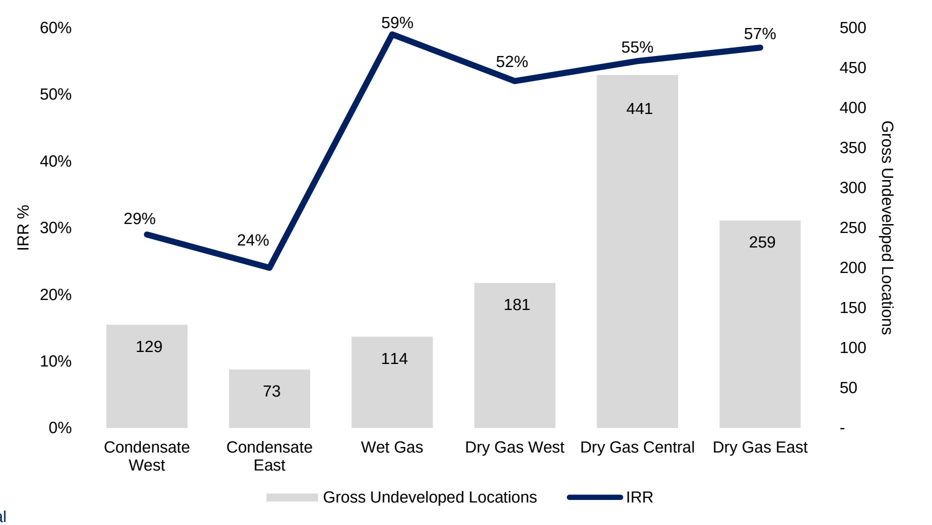
Note: Please refer to page 2 for detail on forward looking statements.
1. As of 12/31/17.
2. During the three months ended 6/30/18.
3. As of 8/1/18.

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]	129	73	114	181	441	259
Net Undeveloped Locations	97	54	86	135	331	194

UTICA SINGLE WELL ECONOMICS[1, 2]



Note: See appendix slide 25 for detailed assumptions used to generate single well IRRs.

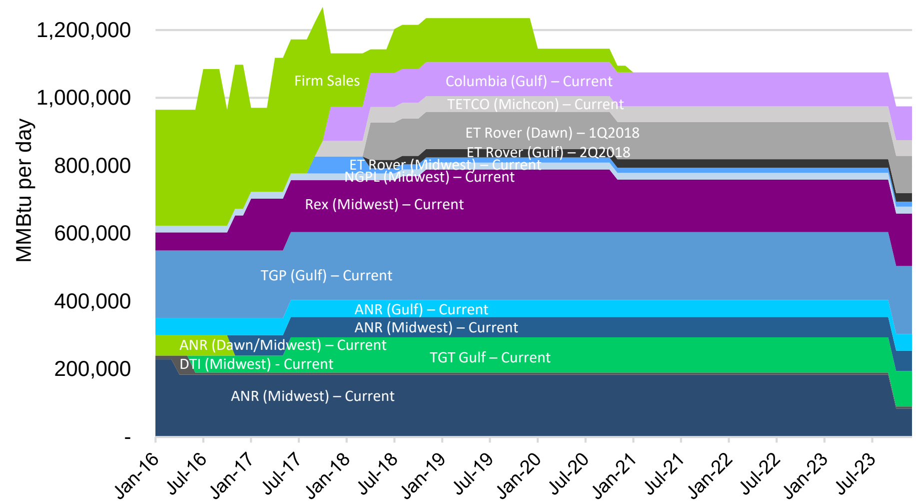
1. Assumes ethane rejection.
2. Well economics assume a flat price case of $3.00 / MMBtu gas, $60.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
3. Assumes net undeveloped locations grossed up from 75% working interest.

UTICA SHALE – OVERVIEW OF FIRM PORTFOLIO

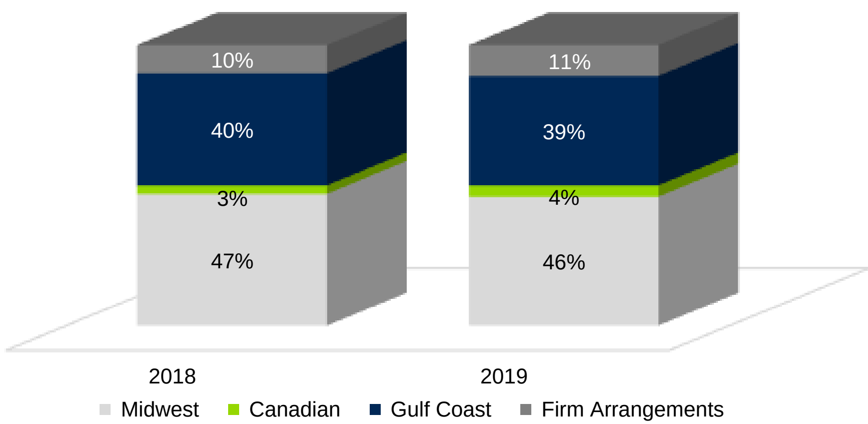
KEY HIGHLIGHTS

- Gulfport was a first-mover in securing early access to premium Midwest markets and transport at low costs out of the basin
- Expanded the firm portfolio as production grew with focus on delivery point diversity and associated costs
- As anticipated, the numerous capacity projects put into service to date has led to a structural improvement in local differentials, advantaging Gulfport as our incremental growth volumes price into a basis tightening, local market

FIRM COMMITMENTS (MMBTU PER DAY)[1]



REGIONAL EXPOSURE AND REALIZED PRICING OF FIRM PORTFOLIO



		2018		2019
NYMEX Strip ($ / MMBtu)	**$**	**2.88**	**$**	**2.74**
Basis Impact ($/ MMBtu)	$	(0.17)	$	(0.22)
Firm Variable Costs ($/ MMBtu)	$	(0.09)	$	(0.09)
Firm Demand Costs ($/ MMBtu)	$	(0.53)	$	(0.53)
Pre-Hedge Realized Price ($/ MMBtu)	**$**	**2.08**	**$**	**1.90**
BTU Uplift (MMBtu / Mcf)	$	0.15	$	0.13
Pre-Hedge Realized Price ($/ Mcf)	**$**	**2.23**	**$**	**2.03**
Total Firm Expense + Basis ($ / MMBtu)	**$**	**(0.80)**	**$**	**(0.84)**
Total Firm Expense + Basis ($ / Mcf)	**$**	**(0.65)**	**$**	**(0.71)**
Dominion South Point Strip ($ / MMBtu)	**$**	**(0.51)**	**$**	**(0.48)**

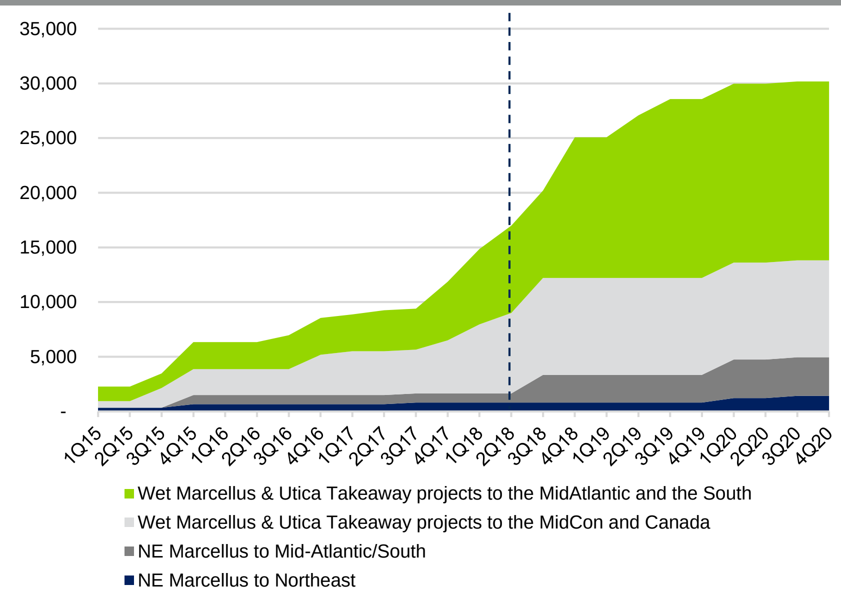
1. Commitments presented as gross volumes.

UTICA SHALE – OVERVIEW OF BASIN TAKEAWAY

KEY HIGHLIGHTS

- The Marcellus and Utica have seen a significant amount of takeaway come online over the past several years
  - Since 2015, there has been over 16 Bcfpd of takeaway capacity put into service
- In addition, over 13 Bcfpd of takeaway projects from this region are anticipated to be put in service between now and year end 2020

INDUSTRY COMMITMENTS MMCFPD[1]



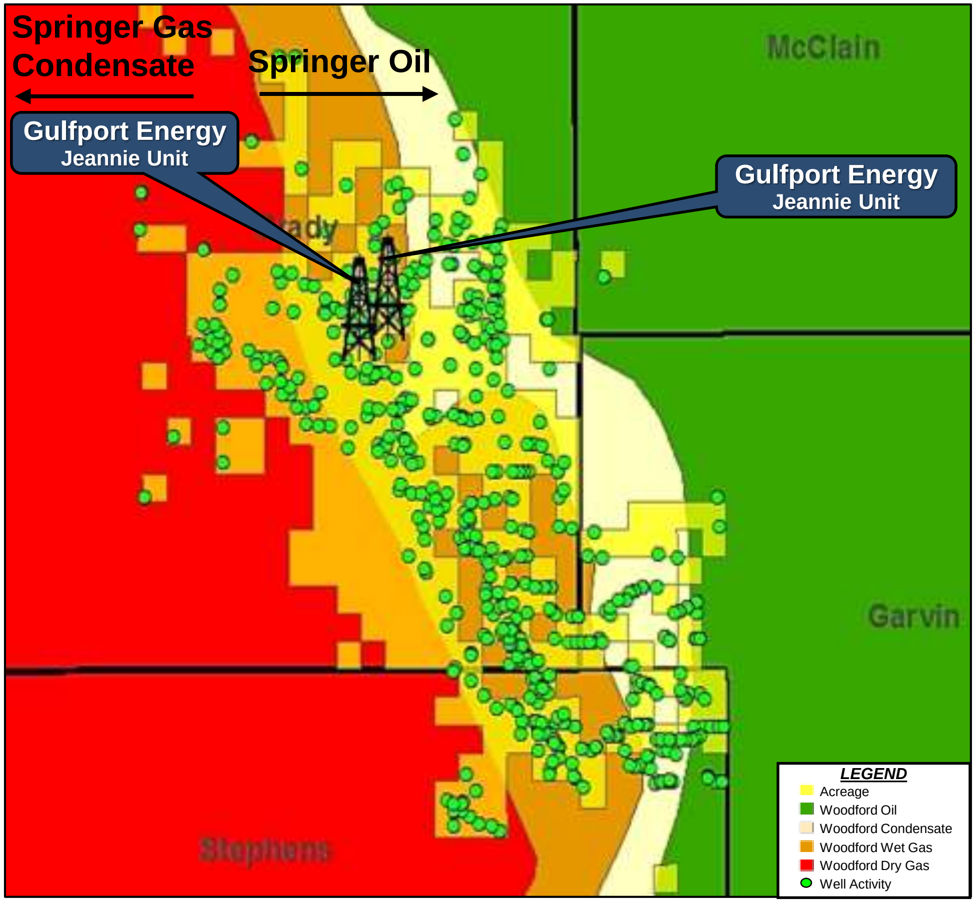
TAKEAWAY PROJECTS[1]

	YE2015	YE2016	YE2017	YE2018	YE2019	YE2020
NE Marcellus to Northeast						
Previous Projects	663	663	808	808	808	808
WMB NE Supply Enhancement	-	-	-	-	-	400
Empire North Project	-	-	-	-	-	205
AGT Access Northeast[2]	-	-	-	-	-	-
Constitution Pipeline[2]	-	-	-	-	-	-
Total	**663**	**663**	**808**	**808**	**808**	**1,413**
NE Marcellus to Mid-Atlantic/South						
Previous Projects	835	835	835	835	835	835
Transco Atlantic Sunrise	-	-	-	1,700	1,700	1,700
PennEast Pipeline	-	-	-	-	-	1,000
Transco Diamond East[2]	-	-	-	-	-	-
Total	**835**	**835**	**835**	**2,535**	**2,535**	**3,535**
Wet Marcellus & Utica Takeaway projects to the MidCon and Canada						
Previous Projects	2,359	3,689	4,848	6,321	6,321	6,321
Rover Pipeline Phase II	-	-	-	1,040	1,040	1,040
Nexus	-	-	-	1,500	1,500	1,500
NFG Northern Access 2016[2]	-	-	-	-	-	-
Total	**2,359**	**3,689**	**4,848**	**8,861**	**8,861**	**8,861**
Wet Marcellus & Utica Takeaway projects to the MidAtlantic and the South						
Previous Projects	2,484	3,360	5,364	6,894	6,894	6,894
TGP SW Louisiana Supply Project	-	-	-	900	900	900
TGP Broad Run Expansion	-	-	-	200	200	200
TCO Mountaineer Xpress	-	-	-	2,700	2,700	2,700
TCO Gulf Xpress	-	-	-	875	875	875
TCO WB Xpress	-	-	-	1,300	1,300	1,300
EQT Mountain Valley	-	-	-	-	2,000	2,000
Dominion Atlantic Coast Pipeline	-	-	-	-	1,500	1,500
Total	**2,484**	**3,360**	**5,364**	**12,869**	**16,369**	**16,369**
Cumulative by End Market						
Northeast Premium	663	663	808	808	808	1,413
MidAtlantic/South	3,319	4,195	6,199	15,404	18,904	19,904
MidCon/Canada	2,359	3,689	4,848	8,861	8,861	8,861
Total	**6,341**	**8,547**	**11,855**	**25,073**	**28,573**	**30,178**

1. Morgan Stanley Commodities Research, "Northeast Pipeline Export Capacity," July 2018. Utilizes Company data, Bentek Energy, and Morgan Stanley Commodities Research. See appendix slide 31 for detail.
2. Pipeline project in service date questionable.

SCOOP ASSET OVERVIEW

SCOOP OVERVIEW



ASSET OVERVIEW

- Net proved reserves of 1.5 Tcfe(1)
- ~92,500 net reservoir acres
  - Includes ~50,200 net Woodford acres and ~42,300 net Springer acres
- Estimate in excess of 40,000 net acres prospective for Sycamore

2018 ACTIVITIES UPDATE(2)

- Average net production of 247.3 MMcfepd
  - ~69% natural gas, 20% natural gas liquids and 11% oil
- ~19% of Gulfport's total net production

2018 PLANNED ACTIVITIES(3)

- Currently running 2 gross operated rigs
- Operated Activity
  - Drill 15 to 16 gross (10 to 11 net) wells
  - Turn-to-sales 20 to 22 gross (16 to 18 net) wells
- Non-Operated Activity
  - Drill 4 to 5 net wells
  - Turn-to-sales 2 to 3 net wells

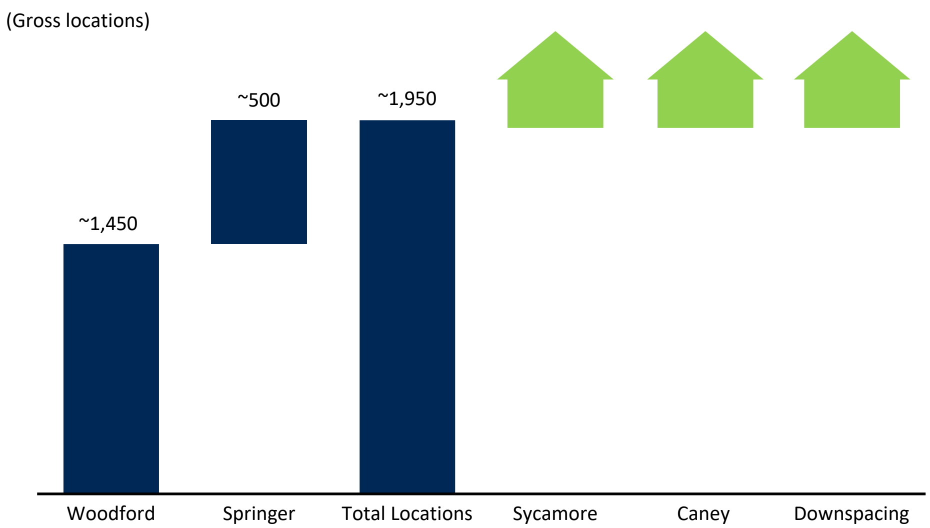
Note: Please refer to page 2 for detail on forward looking statements.
1. As of 12/31/17.
2. During the three months ended 6/30/18.
3. As of 8/1/18.

SCOOP – LARGE STACKED MULTI-PAY INVENTORY

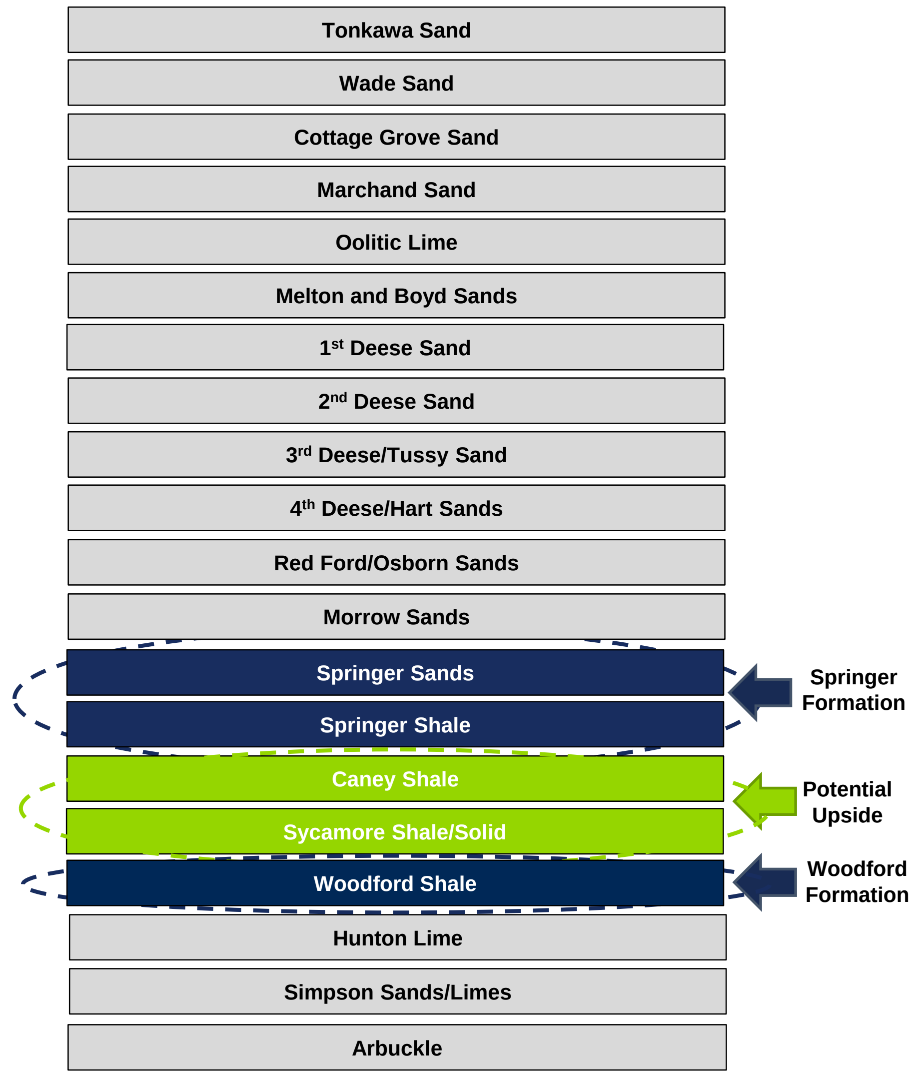
OVERVIEW

- 50,200 net surface acres located in the heart of the SCOOP condensate and over-pressured gas windows with exposure to stacked pay zones
  - ~1,450 gross identified locations in the Woodford formation
  - ~500 gross identified locations in the Springer formation
  - Additional upside from Sycamore, Caney and downspacing
- Decades 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

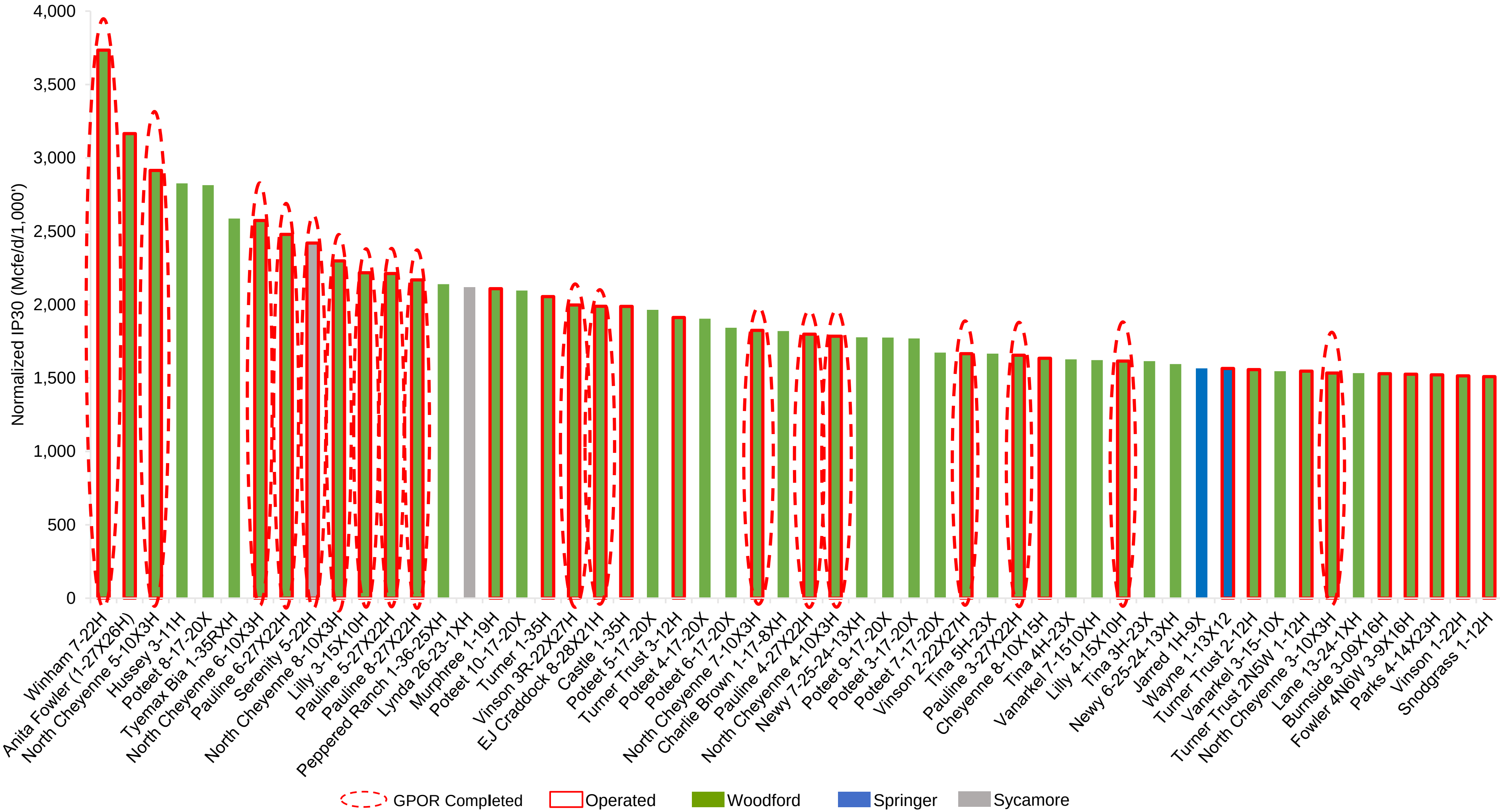
SIGNIFICANT INVENTORY



Formation Overview



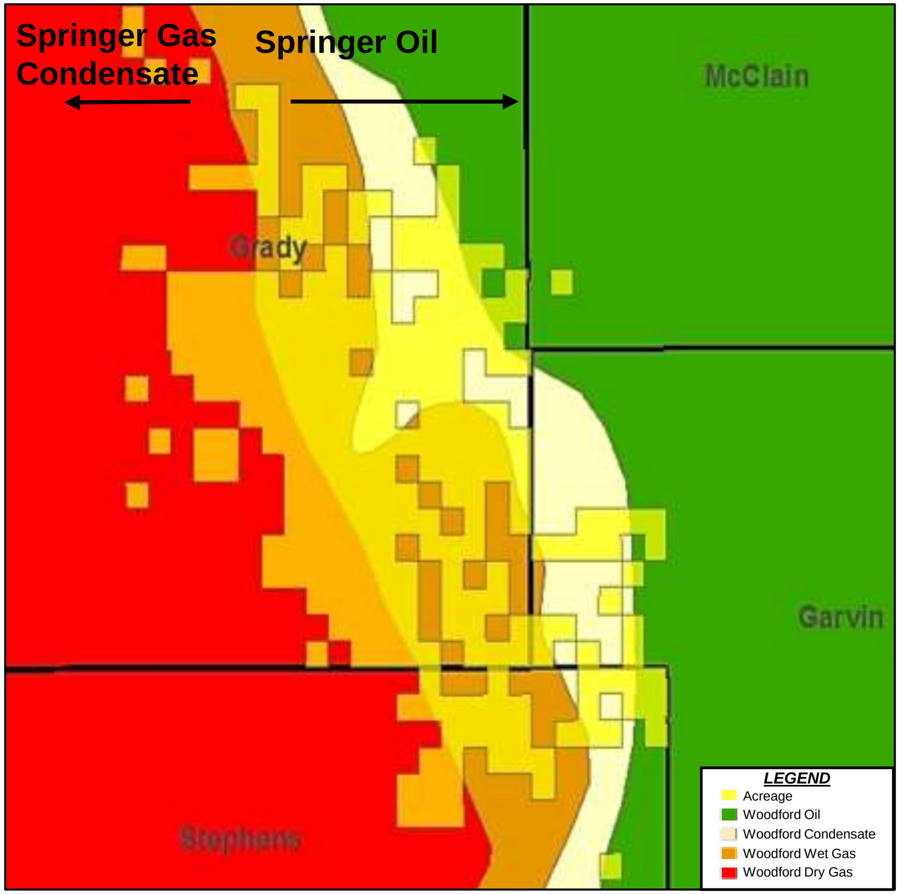
SCOOP – LIST OF HIGH QUALITY RESULTS CONTINUES TO EXPAND



WELL RESULTS CONTINUE TO IMPROVE WITH GULFPORT'S COMPLETED WELLS AT THE TOP OF THE LIST

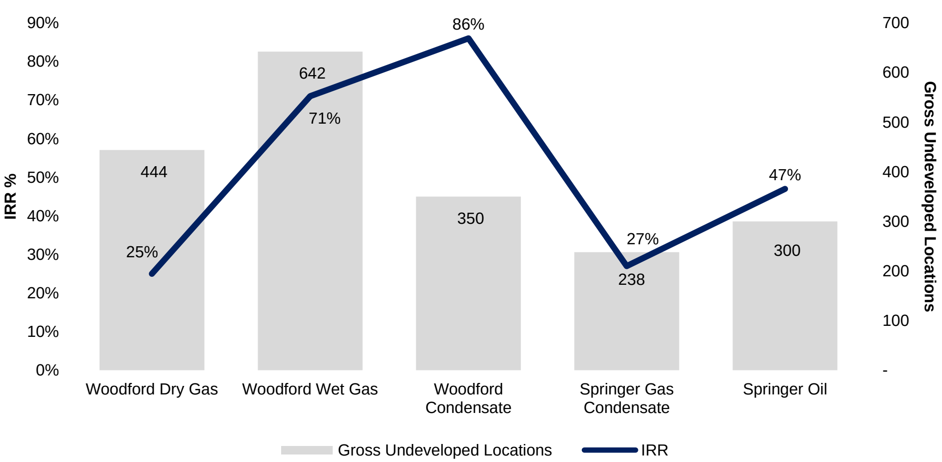
Source: Company provided data and publicly available information. All well results are based upon two-stream production data

SCOOP – TYPE CURVE ASSUMPTIONS



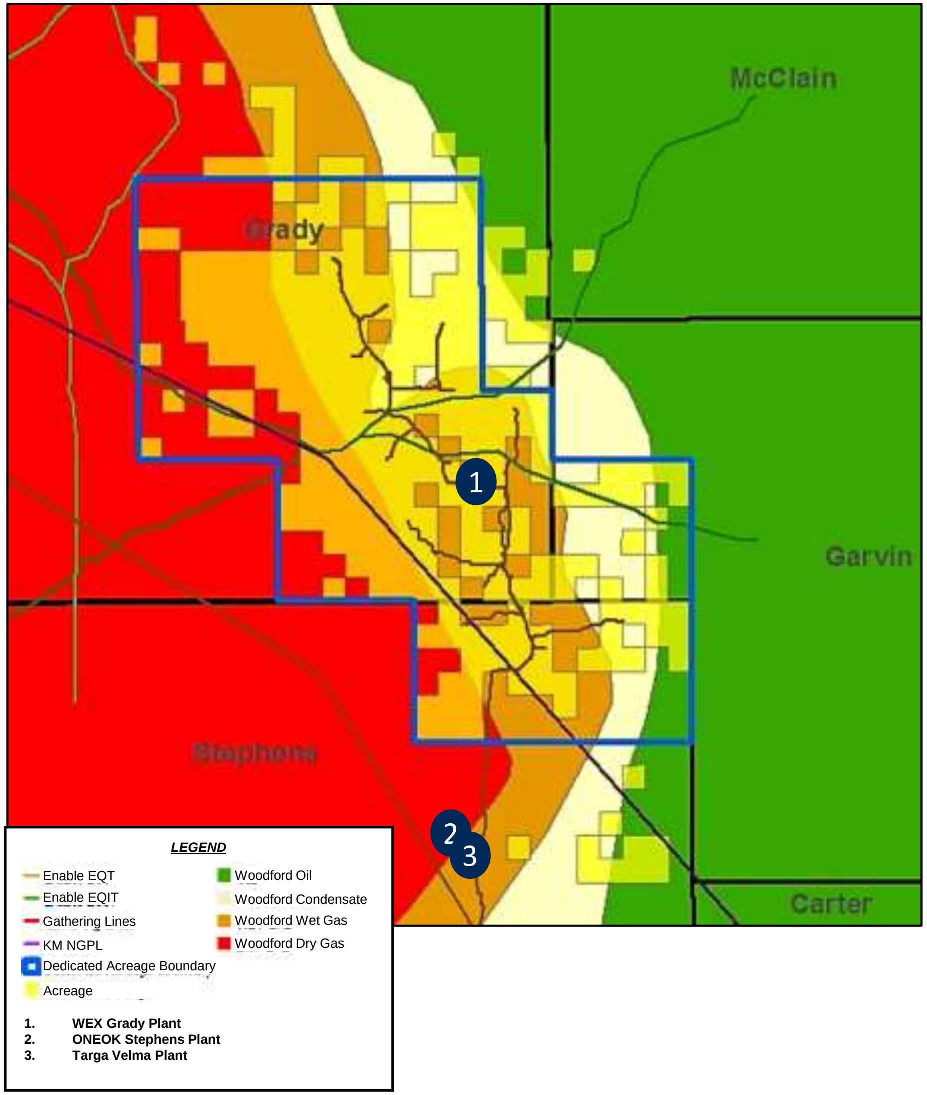
	Woodford			Springer	
	Dry Gas	Wet Gas	Condensate	Springer Gas Condensate	Springer Oil
Type Curve Assumptions					
Lateral Length	7,500	7,500	7,500	7,500	7,500
Well Cost ($MM)	$12.3	$10.5	$9.7	$10.7	$11.0
Well Cost ($ per foot)	$1,633	$1,395	$1,295	$1,429	$1,461
Total EUR (Bcfe / 1,000)	2.6	2.6	1.5	1.7	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	158	243	25	142	110
Identified Net Operated Locations	84	162	18	80	62
Identified Gross Non-Op Locations	286	399	326	96	190
Identified Net Non-Op Locations	1	68	12	2	2
Total Identified Gross Locations	444	642	350	238	300
Total Identified Net Locations	84	230	30	82	64

SCOOP SINGLE WELL ECONOMICS[1, 2]



Note: See appendix slide 33 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery.
2. Well economics assume a flat price case of $3.00 / MMBtu gas, $60.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.

SCOOP – MIDSTREAM GATHERING AND PROCESSING OVERVIEW



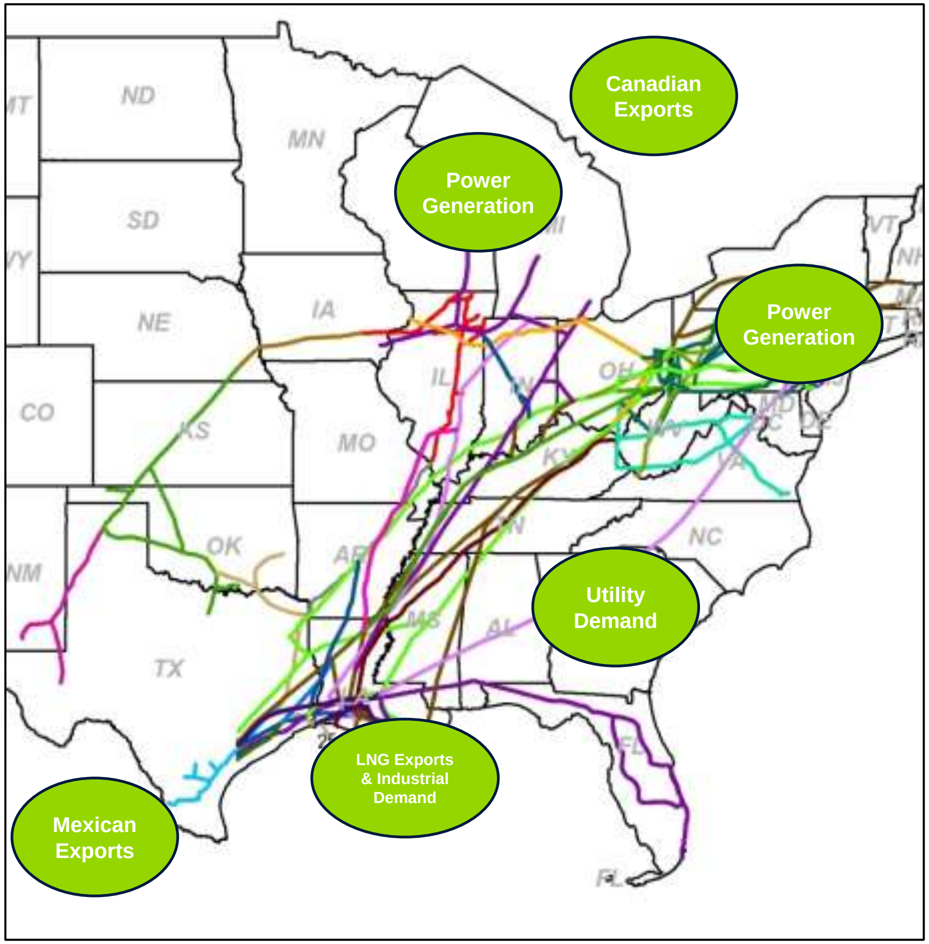
KEY HIGHLIGHTS

- 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
    - Recently expanded to 410 MMcfpd processing capacity
    - Additional connections to Enable, ONEOK and Targa processing plants
- Takeaway overview:
  - Residue Gas: Enable, EOIT, EGT and NGPL (will also include Midship in 1H2019)
  - NGLs: DCP and ONEOK

SCOOP – MARKETING OVERVIEW

KEY HIGHLIGHTS

- Building a diversified gas takeaway portfolio
  - Gulfport holds firm transportation into connecting pipes with multiple deliveries including Bennington, Perryville and points further into the Gulf
  - Firm sales and pricing flexibility offer a combination of pricing locations
  - Takeaway complements our existing Gulf Coast firm transport out of the Utica
  - Gulfport has increased it's commitment as foundation shipper on Cheniere's Midship Pipeline to 300,000 MMBtupd
- 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
- Provides diversity risk by increasing liquids exposure, which provides uplift to realized pricing and enhances corporate margins



UTICA APPENDIX

UTICA SHALE – TYPE CURVE ASSUMPTIONS

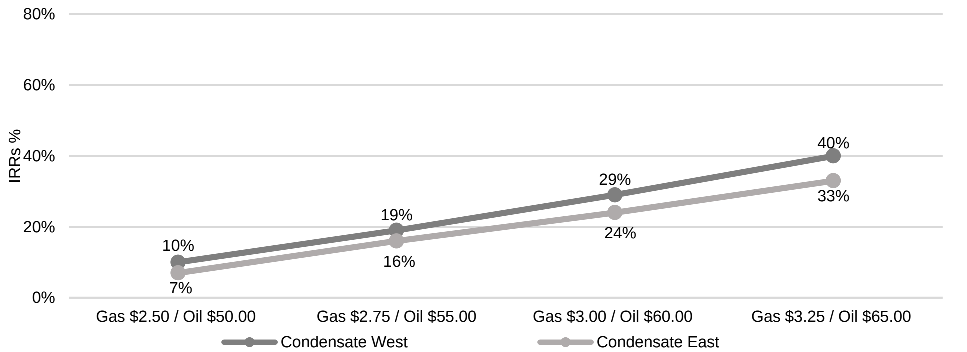
	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Identified Gross Locations[4]	**129**	**73**	**114**	**181**	**441**	**259**
Identified Net Locations	**97**	**54**	**86**	**135**	**331**	**194**
Type Curve Assumptions						
Lateral Length (ft.)	8,000	8,000	8,000	8,000	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)	$ (8.00)	$ (8.00)	$ (8.00)			
NGL (% of WTI)	45%	45%	45%			
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

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.

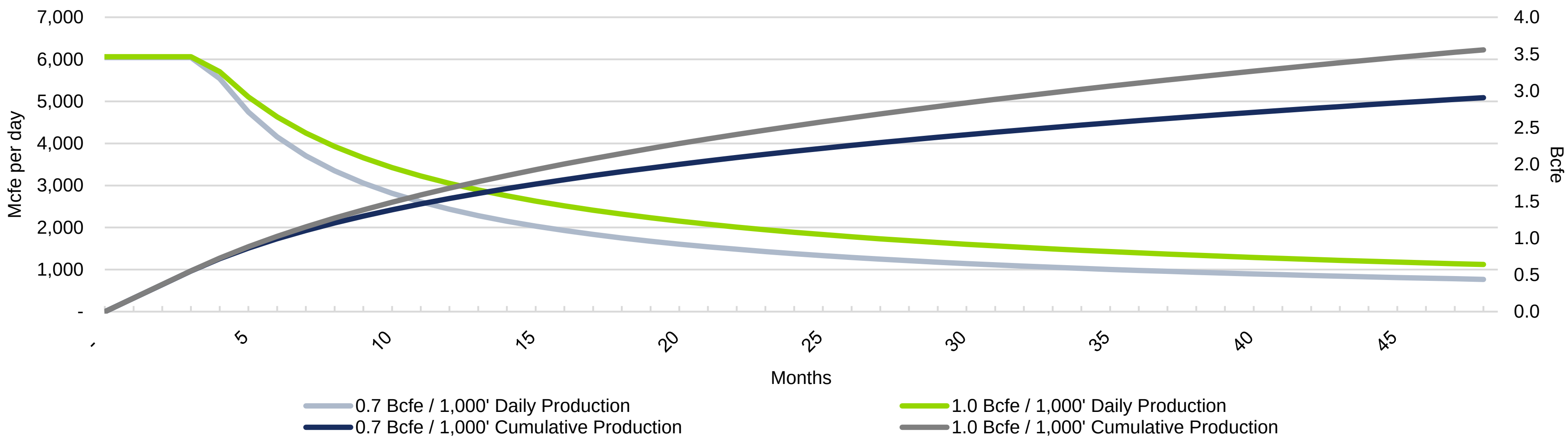
UTICA SHALE – CONDENSATE WINDOW TYPE CURVES

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]	129	73
Net Undeveloped Locations	97	54

SINGLE WELL ECONOMICS[1]



CONDENSATE TYPE CURVES[1]

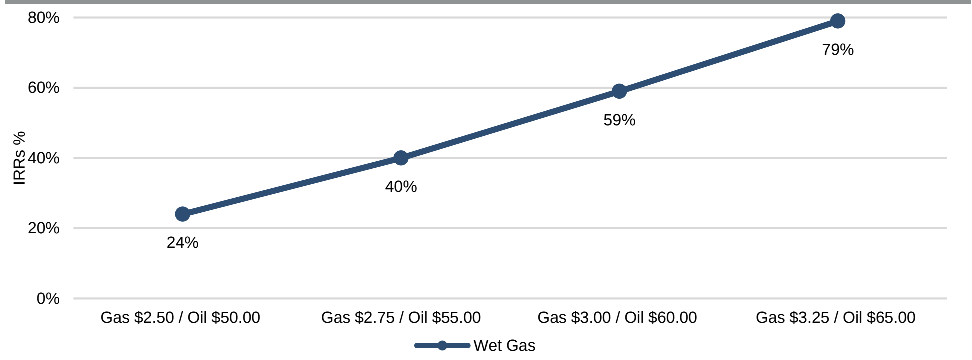


Note: See appendix slide 25 for detailed assumptions used to generate single well IRRs.
1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest

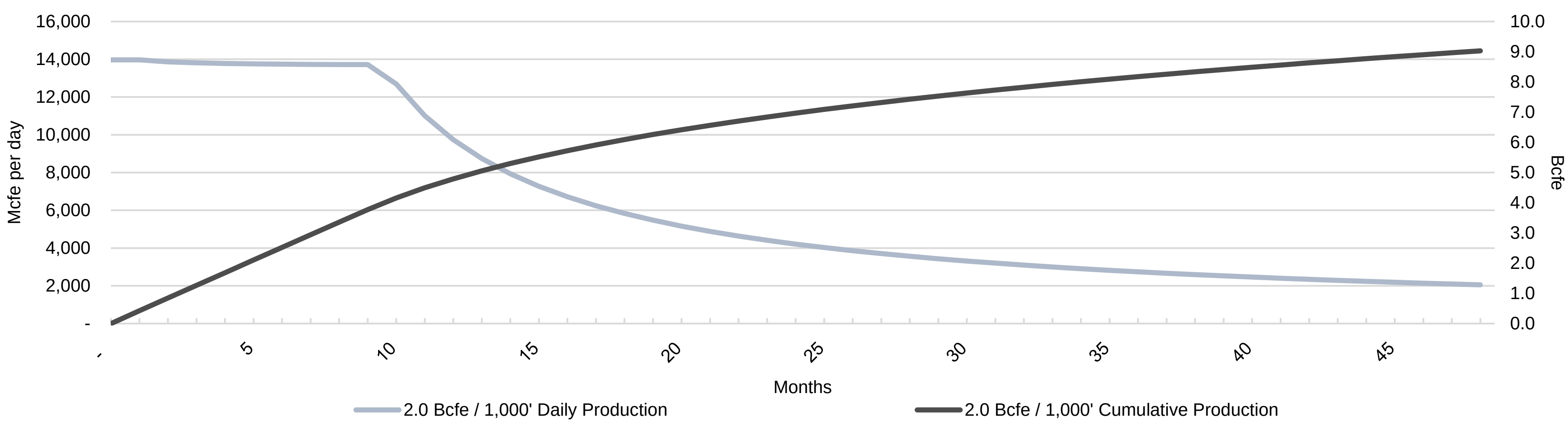
UTICA SHALE – WET GAS WINDOW TYPE CURVES

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)	114
Net Undeveloped Locations	86

SINGLE WELL ECONOMICS(1)



WET GAS TYPE CURVES(1)

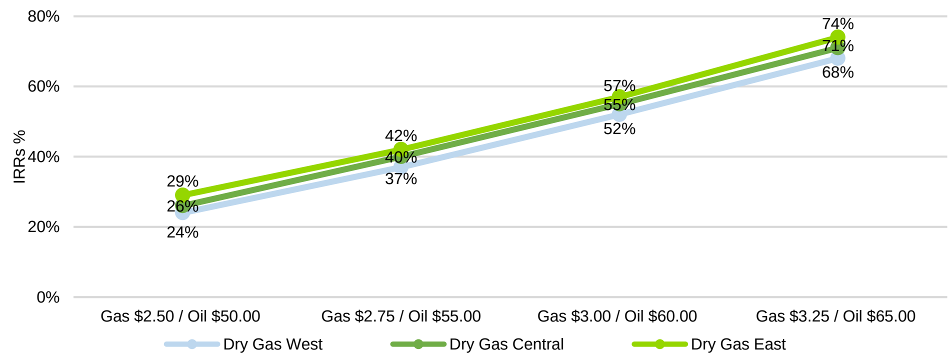


Note: See appendix slide 25 for detailed assumptions used to generate single well IRRs.
1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest.

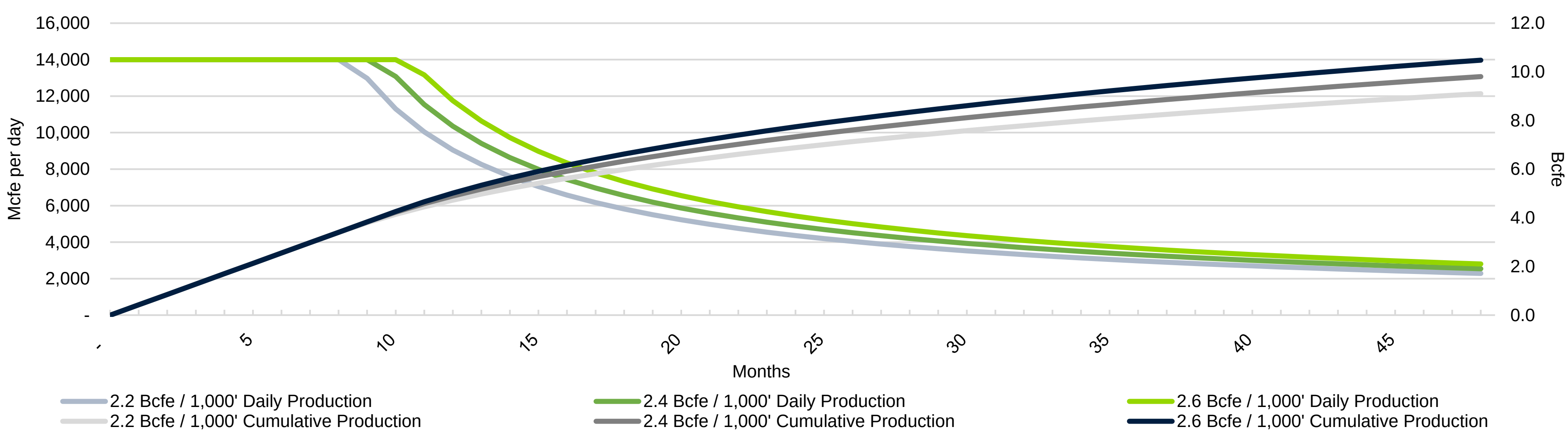
UTICA SHALE – DRY GAS WINDOW TYPE CURVES

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]	181	441	259
Net Undeveloped Locations	135	331	194

SINGLE WELL ECONOMICS[1]

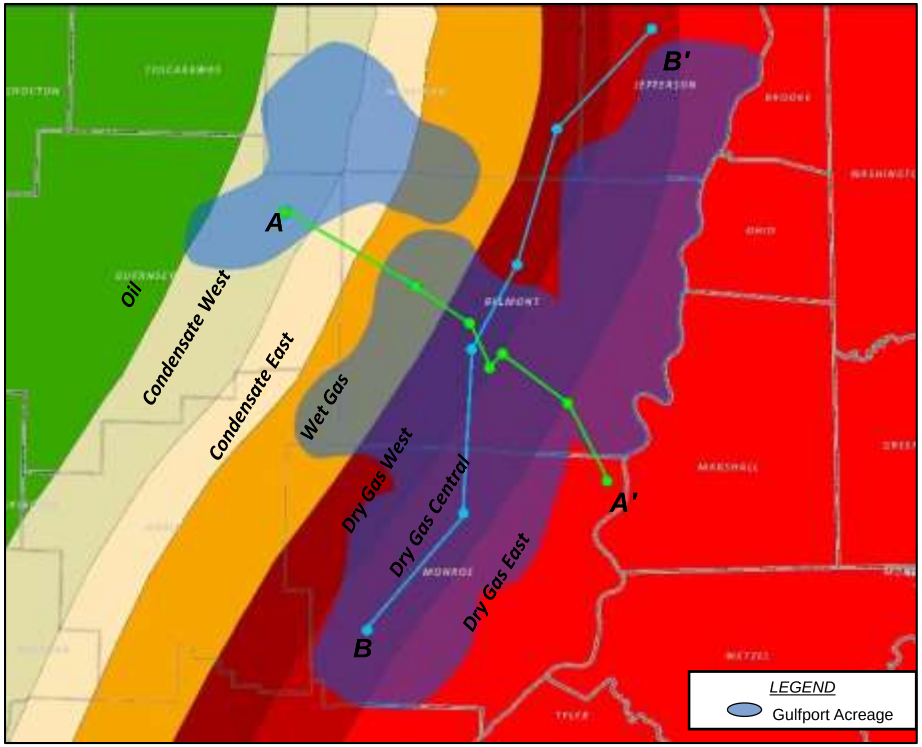


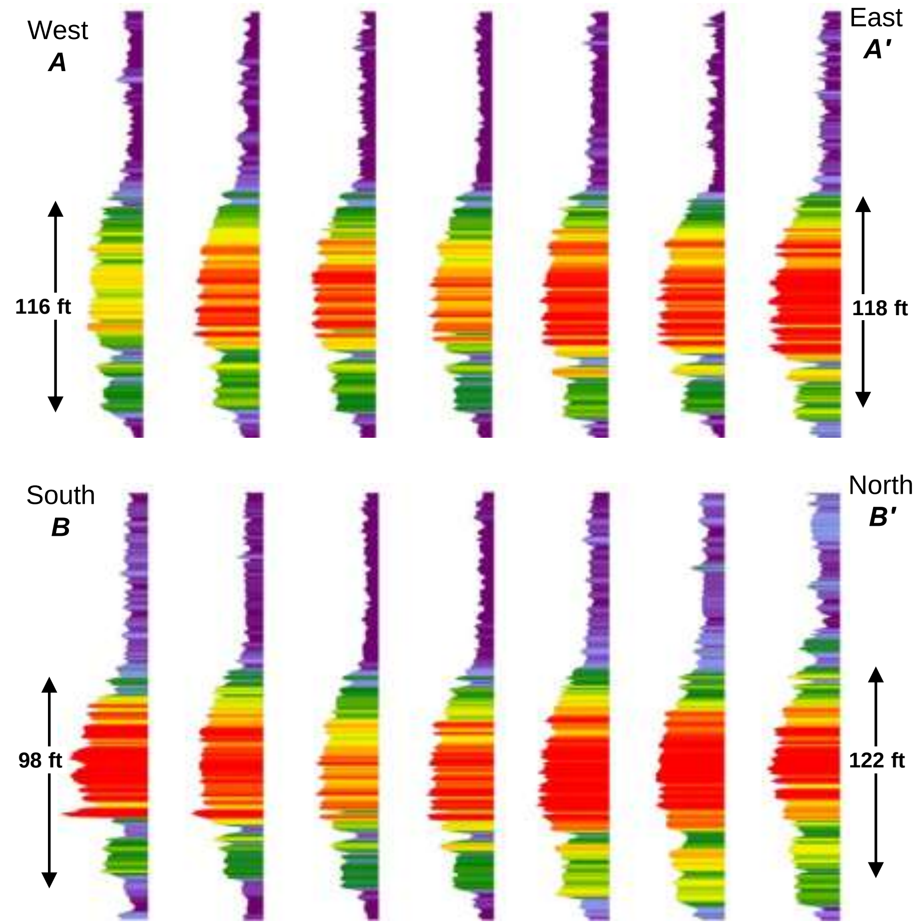
DRY GAS TYPE CURVES[1]



Note: See appendix slide 25 for detailed assumptions used to generate single well IRRs.
1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest.

UTICA SHALE – CONSISTENCY OF RESERVOIR

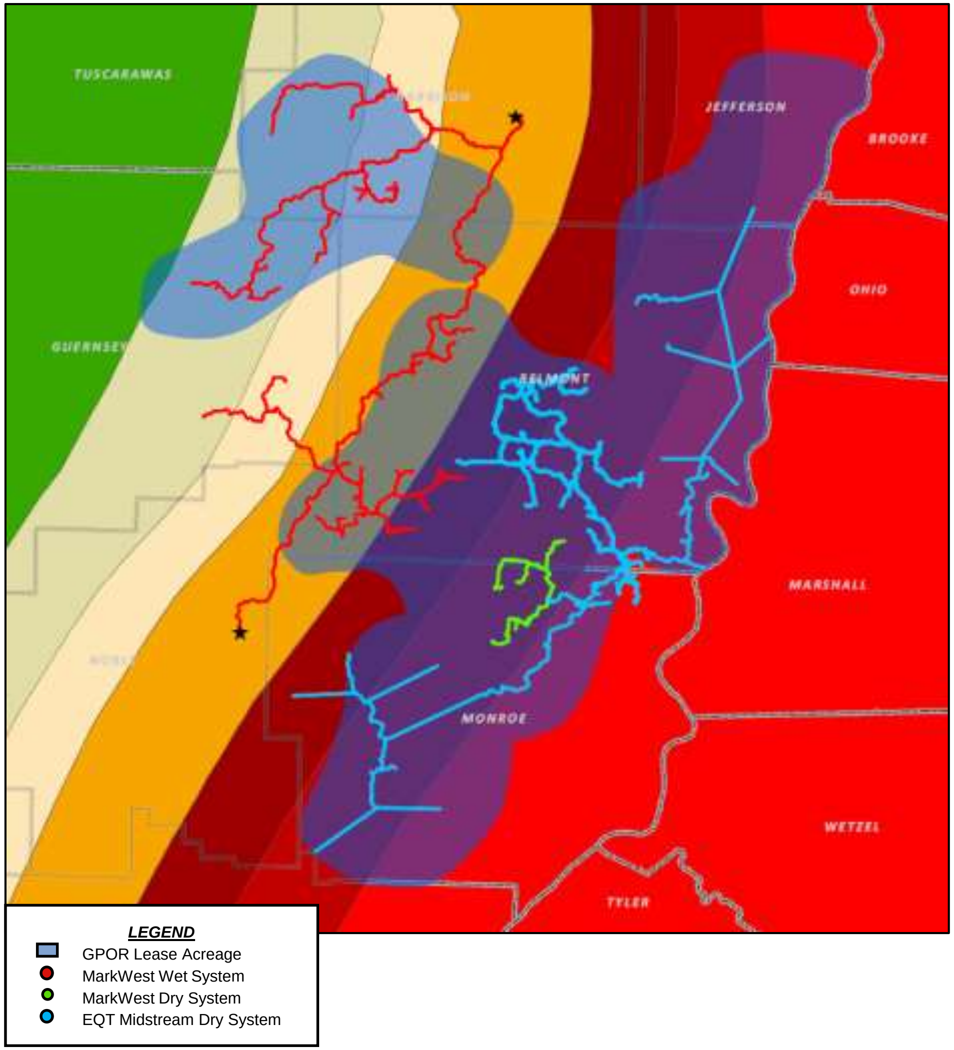




KEY HIGHLIGHTS

- 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 – MIDSTREAM GATHERING AND PROCESSING OVERVIEW



KEY HIGHLIGHTS

- Acreage dedication arrangements to MPLX Energy and EQT Midstream for gathering, processing and fractionation services
  - Competitive contracts with fixed fees and actual fuels and recoveries
  - Anchored position to allow flexible build out and phased in services
- Gathering overview:
  - Made up of 12” to 30” trunk lines throughout the dedication areas
  - Connectivity for dry gas production into multiple transmission pipelines
- Processing overview:
  - MPLX has 1.325 Bcfpd of nameplate processing capacity
  - Two separate facilities – Cadiz and Seneca
- Fractionation overview:
  - MPLX has 40,000 Bpd of C2 at Cadiz with room to expand
  - MPLX has 180,000 Bpd of C3+ at Hopedale expanding by 60,000 Bpd in 4Q18
  - Connectivity to Houston Complex
  - Rail terminal and product pipeline connectivity
- Takeaway overview:
  - Residue Gas: DEO, REX, TETCO, Rover and TCO

NORTHEAST PIPELINE EXPANSION LIST

	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20
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	158	158	158
NFG West Side Expansion	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
TGP Susquehanna West Projeect							145	145	145	145	145	145	145	145	145	145	145	145	145	145
WMB NE Supply Enhancement																	400	400	400	400
Empire North Project																			205	205
AGT Access Northeast(1)																				
Constitution Pipeline(1)																				
Total	**663**	**663**	**663**	**663**	**663**	**663**	**808**	**808**	**808**	**808**	**808**	**808**	**808**	**808**	**808**	**808**	**1,208**	**1,208**	**1,413**	**1,413**
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	310	310	310
TRANSCO Leidy Southeast Project	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
Transco Atlantic Sunrise											1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
PennEast Pipeline																	1,000	1,000	1,000	1,000
Transco Diamond East(1)																				
Total	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**2,535**	**2,535**	**2,535**	**2,535**	**2,535**	**2,535**	**3,535**	**3,535**	**3,535**	**3,535**
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	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	425	425	425
ANR Glen Karn	134	134	134	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	850	850	850	850
REX Zone 3 Capacity Enhancement				480	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Rover Pipeline Phase I								737	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210
TETCO Lebanon								102	102	102	102	102	102	102	102	102	102	102	102	102
Rover Pipeline Phase II										1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Nexus											1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
NFG Northern Access 2016(1)																				
Total	**2,359**	**2,359**	**2,359**	**3,689**	**4,009**	**4,009**	**4,009**	**4,848**	**6,321**	**7,361**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**
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	550	550	550
TGP Broad Run Flexibility	590	590	590	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	626	626	626	626
TETCO Gulf Market Expansion Phase 1				250	250	250	250	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	384	384	384	384
TETCO Adair Southwest								200	200	200	200	200	200	200	200	200	200	200	200	200
TETCO Access South								320	320	320	320	320	320	320	320	320	320	320	320	320
TCO Rayne Xpress								1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
TCO Leach Express									1,530	1,530	1,530	1,530	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	900	900	900	900
TGP Broad Run Expansion										200	200	200	200	200	200	200	200	200	200	200
TCO Mountaineer Xpress												2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
TCO Gulf Xpress												875	875	875	875	875	875	875	875	875
TCO WB Xpress												1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
EQT Mountain Valley														2,000	2,000	2,000	2,000	2,000	2,000	2,000
Dominion Atlantic Coast Pipeline															1,500	1,500	1,500	1,500	1,500	1,500
Total	**2,484**	**2,484**	**3,110**	**3,360**	**3,360**	**3,744**	**3,744**	**5,364**	**6,894**	**7,994**	**7,994**	**12,869**	**12,869**	**14,869**	**16,369**	**16,369**	**16,369**	**16,369**	**16,369**	**16,369**
Cumulative by End Market																				
Northeast Premium	663	663	663	663	663	663	808	808	808	808	808	808	808	808	808	808	1,208	1,208	1,413	1,413
MidAtlantic/South	3,319	3,319	3,945	4,195	4,195	4,579	4,579	6,199	7,729	8,829	10,529	15,404	15,404	17,404	18,904	18,904	19,904	19,904	19,904	19,904
MidCon/Canada	2,359	2,359	2,359	3,689	4,009	4,009	4,009	4,848	6,321	7,361	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861
Total	**6,341**	**6,341**	**6,967**	**8,547**	**8,867**	**9,251**	**9,396**	**11,855**	**14,858**	**16,998**	**20,198**	**25,073**	**25,073**	**27,073**	**28,573**	**28,573**	**29,973**	**29,973**	**30,178**	**30,178**

Source: Morgan Stanley Commodities Research, "Northeast Pipeline Export Capacity," July 2018. Utilizes Company data, Bentek Energy, and Morgan Stanley Commodities Research.
1. Pipeline project in service date questionable.

SCOOP APPENDIX

SCOOP – TYPE CURVE ASSUMPTIONS

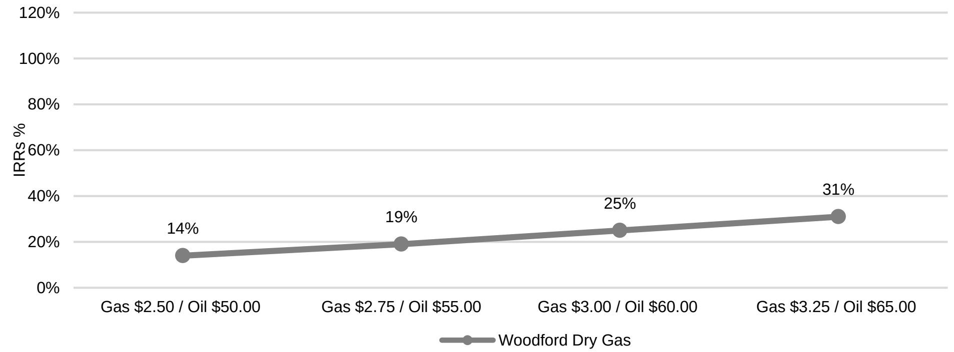
	Woodford Dry Gas	Woodford Wet Gas	Woodford Condensate
Identified Gross Locations	**444**	**642**	**350**
Identified Net Locations	**84**	**230**	**30**
<u>Type Curve Assumptions</u>			
Lateral Length (ft.)	7,500	7,500	7,500
Wells/section	8	8	8
Initial Gas Production (Mcf/d)(1)	14,000	11,000	6,000
Initial Oil Production (Bbl/d)(1)	-	325	740
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%
<u>Unhedged Pricing</u>(3)			
Gas ($ / MMBtu off NYMEX)	$ (0.45)	$ (0.45)	$ (0.45)
Condensate ($ / Bbl off WTI)		$ (3.25)	$ (3.25)
NGL (% of WTI)		50%	50%
<u>Operating Expenses</u>			
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%
<u>Well Cost Assumptions</u>			
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 production.
2. Assumes contractual ethane recovery.
3. Includes transportation costs and basis differentials.

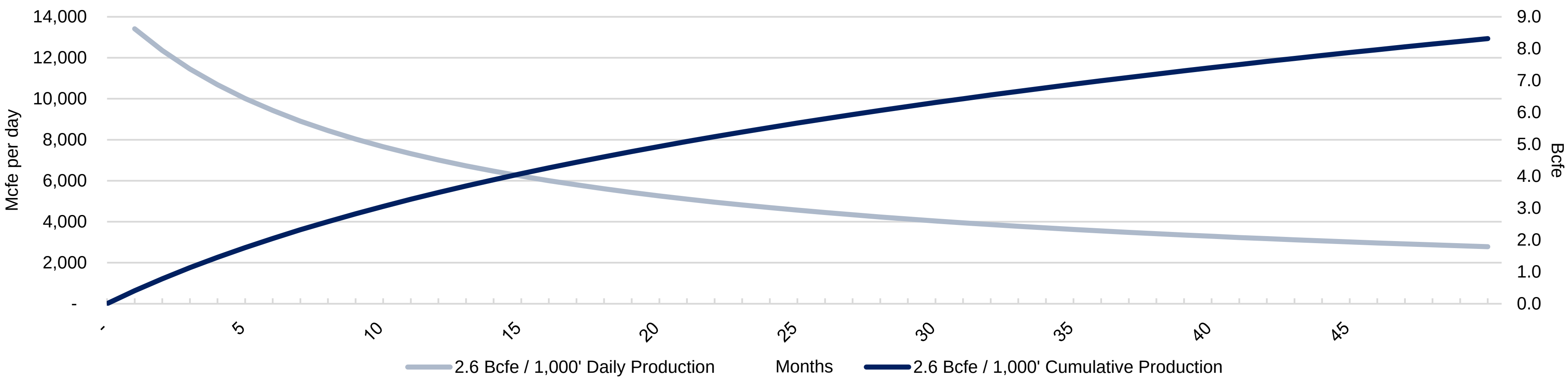
SCOOP – WOODFORD DRY GAS WINDOW TYPE CURVES

Type Curve Assumptions[1]	Woodford 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	444
Net Undeveloped Locations	84

SINGLE WELL ECONOMICS[1]



WOODFORD DRY GAS TYPE CURVES[1]

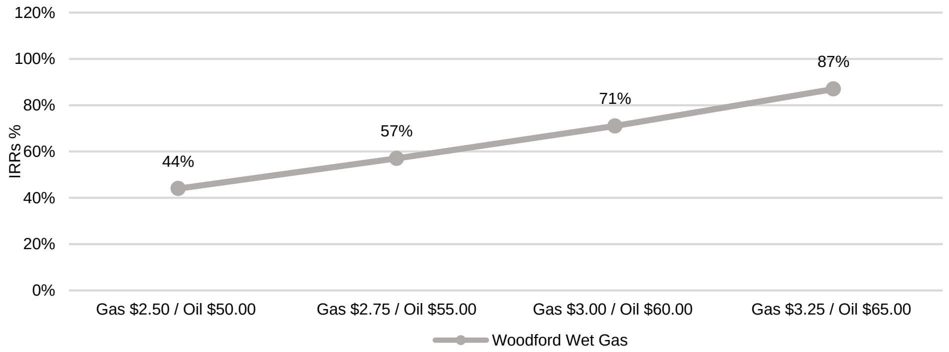


Note: See appendix slide 33 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery..

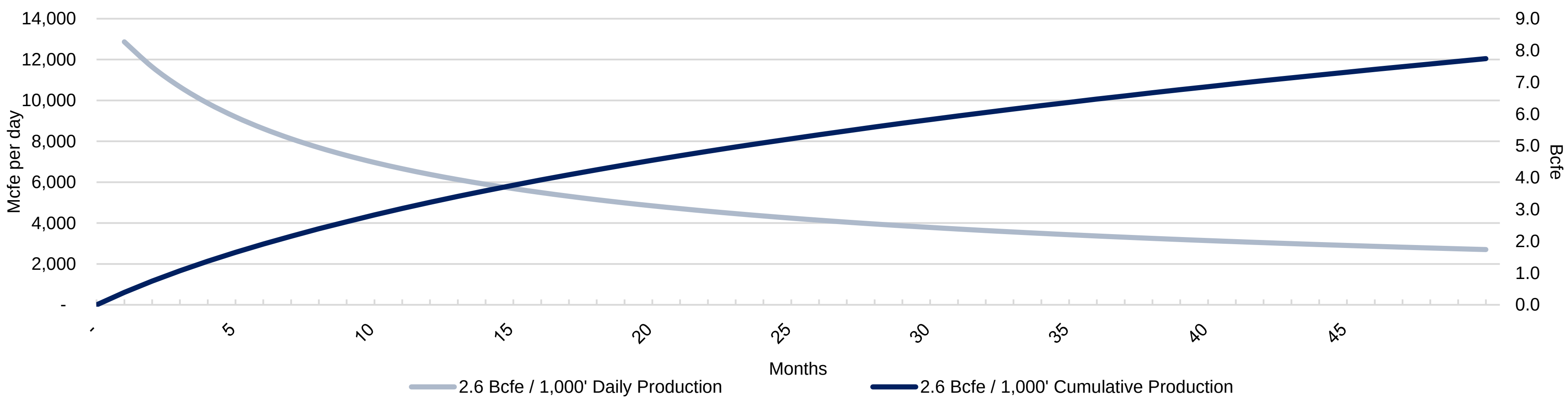
SCOOP – WOODFORD WET GAS WINDOW TYPE CURVES

Type Curve Assumptions[1]	Woodford 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	642
Net Undeveloped Locations	230

SINGLE WELL ECONOMICS[1]



WOODFORD WET GAS TYPE CURVES[1]

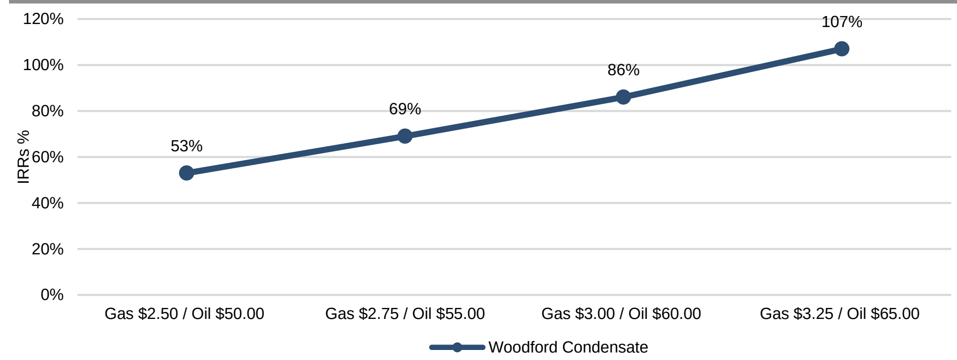


Note: See appendix slide 33 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery.

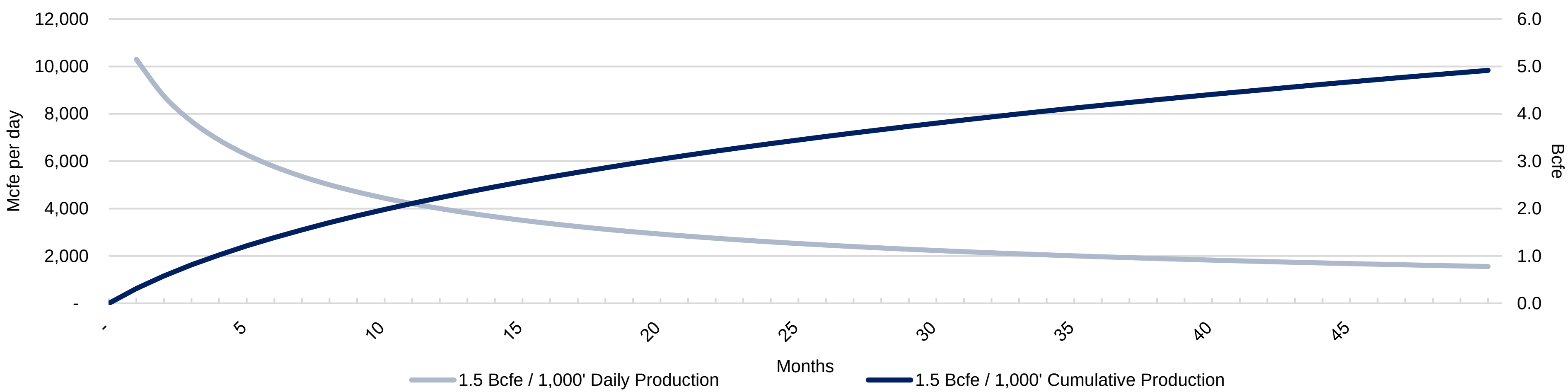
SCOOP – WOODFORD CONDENSATE WINDOW TYPE CURVES

Type Curve Assumptions[1]	Woodford 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	350
Net Undeveloped Locations	30

SINGLE WELL ECONOMICS[1]

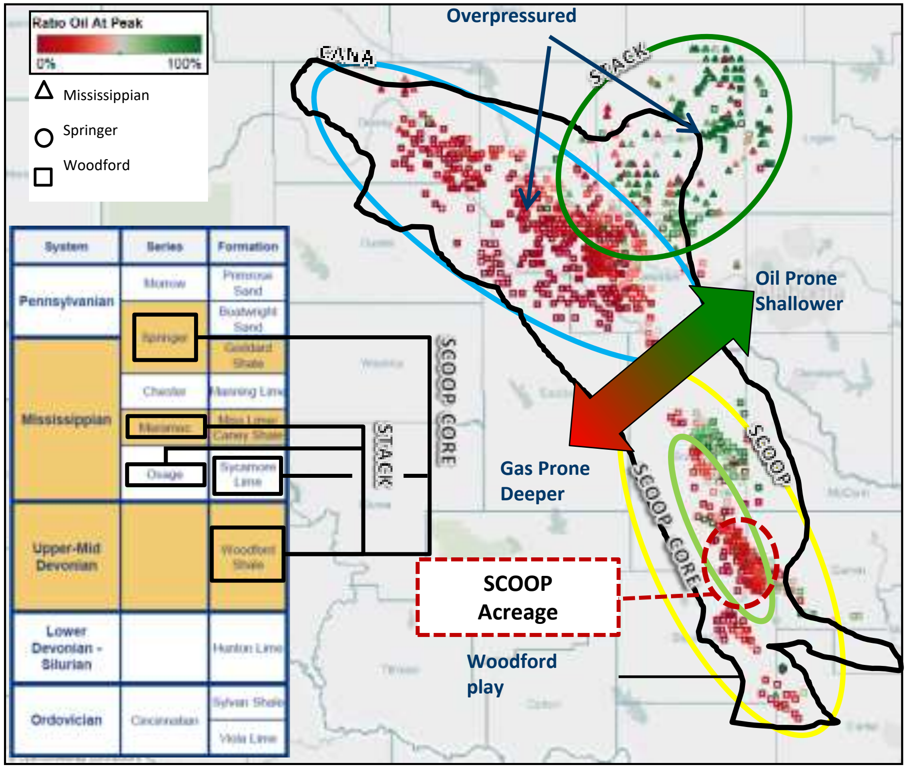


WOODFORD CONDENSATE TYPE CURVES[1]



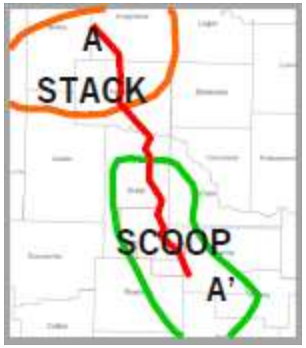
Note: See appendix slide 33 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery..

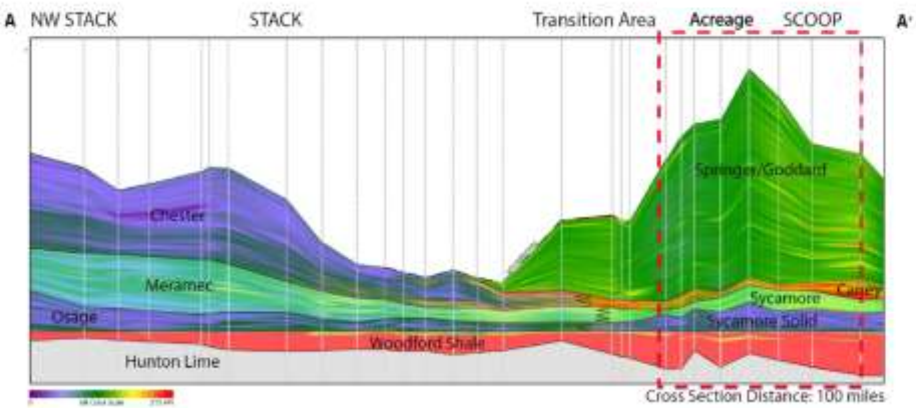
OVERVIEW



REGIONAL STRATIGRAPHY

- Woodford was deposited on an erosional surface and varies in thickness, increasing to the south into the SCOOP
- Sycamore section in 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.

APPENDIX

HISTORY OF GULFPORT

— Gulfport Energy Corporation ("GPOR") is an independent E&P company based in Oklahoma City, OK

1997 – 1998

PHASE 1: FORMATION / ASSET FOCUS

- 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

1998 – 2005

PHASE 2: LOW RISK DEVELOPMENT

- 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

2005 – 2007

PHASE 3: RESOURCE DIVERSIFICATION

- 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

2007 – 2012

PHASE 4: RESOURCE PLAY ADDITION

- 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

2012 – TODAY

PHASE 5: RESOURCE DEVELOPMENT AND EXPANSION

- Initiated drilling program to begin developing Utica Shale resource and currently actively developing acreage
- 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 actively developing acreage

SOUTHERN LOUISIANA

ASSET OVERVIEW

— Net proved reserves of 2.4 MMBoe(1)

— 10,816 net acres

— Gulfport operated

2018 ACTIVITIES UPDATE(2)

— Average net production of 2,454 Boepd during 2Q2018

— ~1% of Gulfport's total net production

— ~100% oil weighted production mix

  – Priced as high quality LLS crude and sold at a premium to WTI

Note: Please refer to page 2 for detail on forward looking statements.
1. As of 12/31/17.
2. During the three-month period ended 6/30/18.

MAMMOTH ENERGY SERVICES

MAMMOTH ENERGY OVERVIEW

- 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 is 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 received ~2.1 million shares of TUSK shares at the time of the closing
- Gulfport holds ~9.8 million[(1)] shares, equating to ~22% 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
  - Other energy services
- Gulfport’s ownership in Mammoth Energy equates to ~$350 million[(2)] in value

Note: Gulfport Energy Corporation holds ~9.8 million shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK). Please refer to page 2 for detail on forward looking statements.
1. As of 7/31/18.
2. Calculated as of the close of the market on 7/31/18 at a price of $37.22 per share.

NGL MARKETING OVERVIEW

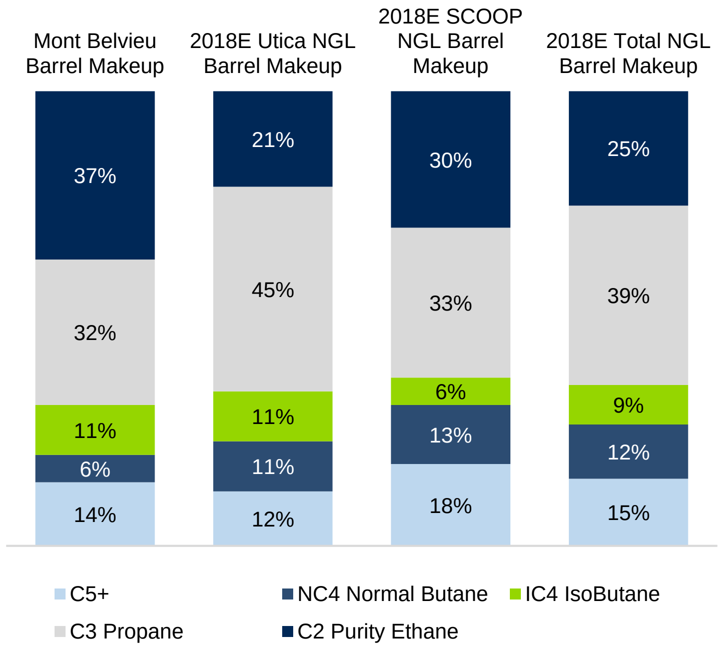
KEY HIGHLIGHTS

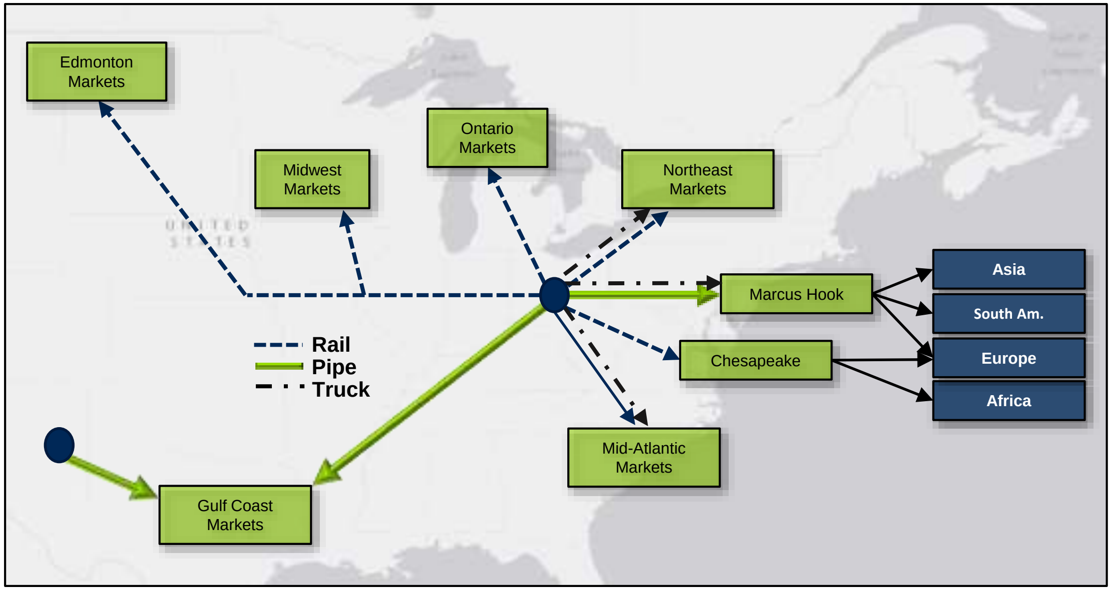
— Gulfport forecasts realizing approximately 45% to 50% of WTI for NGLS during 2018

— SCOOP barrel provides a strong baseload with pipeline access to Mont Belvieu, 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





KEY INFRASTRUCTURE PROGRESS IN NE

— Pipelines in service or being constructed to move product to market include:
  - Mariner West – ~50 Mbpd ethane takeaway to Canada put into service 2013
  - Mariner East 1 – ~75 Mbpd ethane/propane takeaway to Marcus Hook put into service 2014
  - ATEX – ~145 Mbpd ethane takeaway to Mont Belvieu put into service 2014
  - Utopia – ~50 Mbpd ethane takeaway to Ontario put into service January 2018
  - Mariner East 2 – ~275 Mbpd propane/butane takeaway to Marcus Hook and initial capacity estimated to be in service by 2H18

— In addition, demand infrastructure in-basin continues to progress as plants come to service:
  - Shell Chemical's ~1.6 Mtpa polyethylene cracker to be in service 2020/2021
  - PTT Global ~1.5 Mtpa ethylene cracker with FID in 2018

HEDGED PRODUCTION

HEDGE BOOK[1]

	3Q18	4Q18	2018	2019
Natural Gas Contract Summary:				
Natural Gas Fixed Price Swaps (NYMEX)				
Volume (BBtupd)	1,010	1,010	948	1,154
Weighted Average Price ($/MMBtu)	$ 3.01	$ 3.01	$ 3.05	$ 2.81
Natural Gas Fixed Price Swaptions (NYMEX)[2]				
Volume (BBtupd)	50	50	43	135
Weighted Average Price ($/MMBtu)	$ 3.13	$ 3.13	$ 3.10	$ 3.07
Total Potential Natural Gas Volumes (BBtupd)	1,060	1,060	991	1,289
Total Weighted Average Price ($/MMBtu)	$ 3.01	$ 3.01	$ 3.05	$ 2.84
Basis Contract Summary:				
NGPL MidCon				
Volume (BBtupd)	-	-	12	-
Differential ($/MMBtu)	$ -	$ -	$ (0.26)	$ -
Transco Zone 4				
Volume (BBtupd)	-	40	10	60
Differential ($/MMBtu)	$ -	$ (0.05)	$ (0.05)	$ (0.05)
Oil Contract Summary:				
Oil Fixed Price Swaps (LLS)				
Volume (Bblpd)	2,000	2,000	1,507	1,000
Weighted Average Price ($/Bbl)	$ 56.22	$ 56.22	$ 56.22	$ 59.55
Oil Fixed Price Swaps (WTI)				
Volume (Bblpd)	4,500	4,500	4,779	4,000
Weighted Average Price ($/Bbl)	$ 53.72	$ 53.72	$ 54.29	$ 58.28
Total Potential Crude Oil (Bblpd)	6,500	6,500	6,286	5,000
Total Weighted Average Price ($/Bbl)	$ 54.48	$ 54.48	$ 54.75	$ 58.53
Propane Contract Summary:				
C3 Propane Fixed Price Swaps				
Volume (Bblpd)	4,000	4,000	4,000	3,000
Weighted Average Price ($/Gal)	$ 0.69	$ 0.69	$ 0.69	$ 0.66
C5+ Pentane Fixed Price Swaps				
Volume (Bblpd)	500	500	500	500
Weighted Average Price ($/Gal)	$ 1.11	$ 1.11	$ 1.11	$ 1.29

1. As of August 1, 2018.
2. Counterparty has option to call.

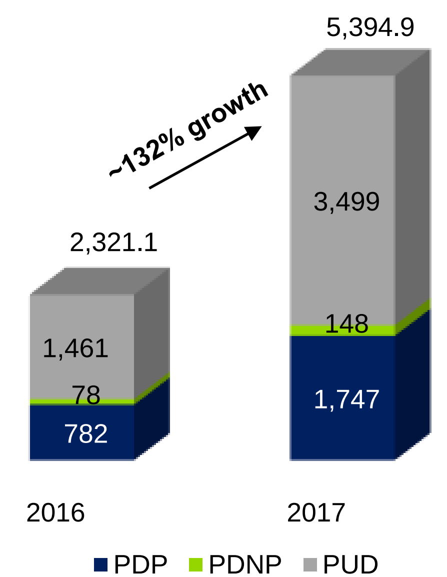
FINANCIAL AND OPERATIONAL SUMMARY

	2016					2017					2018					2Q2018	
	1Q2016	2Q2016	3Q2016	4Q2016	FY 2016	1Q2017	2Q2017	3Q2017	4Q2017	FY 2017	1Q2018	2Q2018	YTD 2018	FY 2018E		Q-o-Q	Y-o-Y
Production																	
Gas – Bcf	53.3	52.8	58.2	63.4	227.6	66.3	82.9	97.8	103.0	350.1	102.0	108.2	210.3			6%	31%
Oil - MBbls	601.8	551.5	521.4	451.2	2,125.9	513.7	650.0	685.3	730.4	2,579.4	756.9	744.3	1,501.2			(2%)	15%
Liquids - MBbls	1,012.6	734.6	1,043.7	1,055.8	3,846.7	1,182.6	1,281.1	1,405.0	1,465.6	5,334.2	1,565.6	1,393.1	2,958.8			(11%)	9%
Total Equivalent (Bcfe)	63.0	60.5	67.5	72.4	263.4	76.5	94.5	110.4	116.2	397.6	116.0	121.1	237.0			4%	28%
Total Daily Equivalent (Mcfepd)	692,230	664,743	734,144	786,998	719,753	849,569	1,038,351	1,199,636	1,263,319	1,089,159	1,288,631	1,330,342	1,309,602	1,320,000	1,340,000	3%	28%
Product Mix																	
Gas	85%	87%	86%	87%	86%	87%	88%	88%	89%	88%	88%	89%	89%	~89%			
Liquids	15%	13%	14%	13%	14%	13%	12%	12%	11%	12%	12%	11%	11%	~11			
Realized Prices																	
Average Realized Prices before the impact of derivatives ($/Mcfe)	**$1.58**	**$1.81**	**$2.35**	**$2.67**	**$2.13**	**$3.05**	**$2.74**	**$2.61**	**$2.80**	**$2.78**	**$2.95**	**$2.67**	**$2.81**			(9%)	(2%)
Average Realized Prices incl. cash-settlement of derivatives ($/Mcfe)	**$2.61**	**$2.82**	**$2.54**	**$2.80**	**$2.69**	**$2.96**	**$2.79**	**$2.74**	**$2.91**	**$2.85**	**$3.02**	**$2.72**	**$2.87**			(10%)	(2%)
Average Realized Prices including derivatives ($/Mcfe)	**$2.49**	**($0.47)**	**$2.87**	**$0.88**	**$1.46**	**$4.36**	**$3.43**	**$2.41**	**$3.42**	**$3.32**	**$2.81**	**$2.09**	**$2.44**				
Average NYMEX Henry Hub ($/MMBtu)	$2.09	$1.95	$2.81	$2.99	$2.46	$3.31	$3.18	$3.00	$2.93	$3.11	$2.98	$2.80	$2.89			(6%)	(12%)
Differential to Henry Hub ($/MMBtu)	(0.79)	(0.60)	(0.85)	(0.80)	(0.73)	(0.81)	(0.87)	(0.87)	(0.76)	(0.85)	(0.70)	(0.79)	(0.75)				
Natural Gas Realized Price before the impact of derivatives ($/MMBtu)	$1.30	$1.35	$1.96	$2.19	$1.73	$2.50	$2.32	$2.13	$2.17	$2.26	$2.28	$2.01	$2.14				
BTU Upgrade (MMBtu / Scf)	0.09	0.09	0.14	0.15	0.12	0.18	0.16	0.15	0.15	0.16	0.16	0.14	0.15				
Natural Gas Realized Price before the impact of derivatives ($/Mcf)	$1.39	$1.44	$2.10	$2.34	$1.85	$2.68	$2.48	$2.28	$2.32	$2.42	$2.44	$2.15	$2.29				
Differential to Henry Hub ($/Mcf)	*(0.70)*	*(0.51)*	*(0.71)*	*(0.65)*	*(0.61)*	*(0.63)*	*(0.70)*	*(0.72)*	*(0.61)*	*(0.69)*	*(0.54)*	*(0.65)*	*(0.60)*	($0.58)	($0.72)		
Impact of cash settled derivatives ($/Mcf)	1.10	1.09	0.20	0.15	0.60	(0.11)	0.03	0.13	0.18	0.07	0.16	0.17	0.17				
Natural Gas Realized Price incl. cash-settlement of derivatives ($/Mcf)	**$2.49**	**$2.53**	**$2.31**	**$2.49**	**$2.45**	**$2.57**	**$2.51**	**$2.41**	**$2.50**	**$2.49**	**$2.60**	**$2.32**	**$2.46**			(11%)	(8%)
Average NYMEX WTI ($/Bbl)	$33.51	$45.60	$44.94	$49.33	$43.37	$51.86	$48.29	$48.19	$55.39	$50.93	$62.89	$67.90	$65.41			8%	41%
Differential to WTI ($/Bbl)	(7.19)	(3.60)	(3.13)	(4.17)	(5.18)	(4.34)	(2.96)	(2.29)	(1.68)	(2.64)	(2.54)	(1.64)	(2.12)	($3.00)	($3.50)		
Oil Realized Price before the impact of derivatives ($/Mcf)	$26.32	$42.00	$41.81	$45.15	$38.18	$47.52	$45.33	$45.90	$53.71	$48.29	$60.36	$66.26	$63.29				
Impact of cash settled derivatives ($/Mcf)	10.54	6.49	1.62	0.22	5.11	0.16	3.58	4.37	(1.78)	1.59	(5.64)	(10.97)	(8.29)				
Oil Realized Price incl. cash-settlement of derivatives ($/Bbl)	**$36.86**	**$48.49**	**$43.43**	**$45.37**	**$43.29**	**$47.68**	**$48.91**	**$50.26**	**$51.93**	**$49.88**	**$54.72**	**$55.29**	**$55.00**			1%	13%
NGL Realized Price before the impact of derivatives ($/Gal)	$0.22	$0.33	$0.33	$0.56	$0.37	$0.63	$0.45	$0.57	$0.76	$0.61	$0.71	$0.71	$0.71				
Impact of cash settled derivatives ($/Gal)	0.01	-	-	(0.01)	(0.01)	-	-	(0.03)	(0.06)	(0.03)	(0.04)	(0.07)	(0.05)				
NGL Realized Price incl. cash-settlement of derivatives ($/Gal)	**$0.23**	**$0.33**	**$0.33**	**$0.55**	**$0.36**	**$0.63**	**$0.45**	**$0.54**	**$0.70**	**$0.58**	**$0.67**	**$0.64**	**$0.66**			(4%)	42%
% WTI	***29%***	***30%***	***31%***	***47%***	***35%***	***51%***	***39%***	***50%***	***58%***	***50%***	***48%***	***44%***	***46%***	45%	50%		
Operating Expenses per Mcfe																	
Lease operating expense	$0.26	$0.24	$0.26	$0.28	$0.26	$0.25	$0.22	$0.18	$0.17	$0.20	$0.16	$0.19	$0.18	$0.17	$0.19	16%	(14%)
Production taxes	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.05	$0.06	$0.06	$0.06	$0.06	$0.08	7%	16%
Midstream gathering and processing	$0.60	$0.65	$0.67	$0.60	$0.63	$0.63	$0.62	$0.63	$0.63	$0.63	$0.55	$0.59	$0.57	$0.57	$0.63	7%	(5%)
Unit Operating Costs	**$0.91**	**$0.94**	**$0.98**	**$0.93**	**$0.94**	**$0.93**	**$0.89**	**$0.86**	**$0.86**	**$0.88**	**$0.77**	**$0.84**	**$0.81**	**$0.80**	**$0.90**	9%	(6%)
Revenues (in thousands)																	
Gas sales	$131,094	($57,860)	$155,185	$25,776	$254,195	$264,114	$262,035	$216,264	$335,730	$1,078,143	$239,702	$201,502	$441,204				
Oil and condensates sales	17,121	20,533	23,507	$14,625	75,786	35,316	37,611	24,888	23,403	121,218	36,538	24,901	61,439				
Liquid sales	8,746	9,168	15,000	$23,015	55,929	33,574	24,307	24,347	38,715	120,943	49,151	26,337	75,488				
Other income, net	2	7	(6)	(132)	(129)	-	-	-	-	-	-	-	-				
Total Revenue	$156,963	($28,152)	$193,686	$63,284	$385,781	$333,004	$323,953	$265,499	$397,848	$1,320,304	$325,391	$252,740	$578,131				
Plus non-cash hedge (gain) loss	7,685	198,685	(22,357)	139,290	323,303	(106,796)	(59,871)	36,974	(59,110)	(188,803)	25,403	76,845	102,248				
Total Revenue excl. non-cash impact from derivatives	**$164,648**	**$170,533**	**$171,329**	**$202,574**	**$709,084**	**$226,208**	**$264,082**	**$302,473**	**$338,738**	**$1,131,501**	**$350,794**	**$329,585**	**$680,379**			(6%)	25%
Expenses (in thousands)																	
Lease operating expense	$16,657	$14,661	$17,471	$20,088	$68,877	$19,303	$20,721	$20,020	$20,202	$80,246	$18,906	$22,912	$41,818				
Production taxes	3,111	2,856	3,525	3,784	13,276	3,906	5,139	5,419	6,662	21,126	6,854	7,659	14,513				
Midstream gathering and processing	37,652	39,349	45,475	43,496	165,972	47,941	58,945	69,372	72,737	248,995	64,193	71,440	135,633				
General and administrative	10,620	11,854	10,467	10,468	43,409	12,600	12,257	13,065	15,016	52,938	13,099	14,008	27,107				
Other	(94)	(391)	(337)	(408)	(1,230)	(1,158)	(250)	(382)	(260)	(2,050)	(132)	(78)	(210)				
Adjusted EBITDA	**$96,702**	**$102,204**	**$94,728**	**$125,146**	**$418,780**	**$143,616**	**$167,270**	**$194,979**	**$224,381**	**$730,246**	**$247,875**	**$213,644**	**$461,519**			(14%)	28%
Depreciation, depletion and amortization	65,477	55,652	62,285	62,560	245,974	65,991	82,246	106,650	109,742	364,629	111,018	121,915	232,933				
Adjusted Net Income (Loss)	**$15,146**	**$30,366**	**$20,018**	**$44,253**	**$109,783**	**$53,864**	**$60,426**	**$57,979**	**$81,730**	**$253,999**	**$101,888**	**$57,010**	**$158,898**				

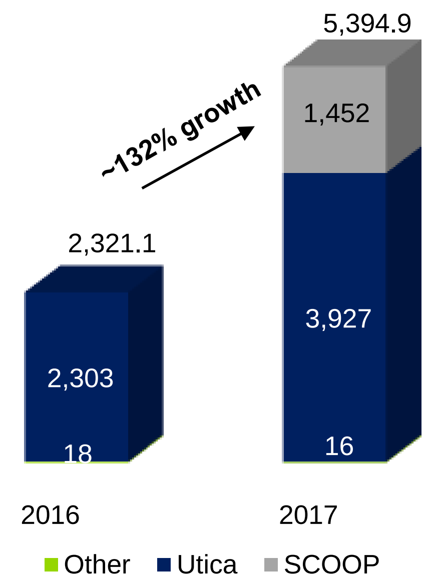
2017 PROVED RESERVE SUMMARY

Net Reserves as of December 31, 2017[1]	Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)	PV-10 ($MM) SEC
Proved Developed Producing	1,495.5	8.5	33.5	1,747.4	$1,699
Proved Developed Non-Producing	121.4	1.7	2.8	148.5	$166
Proved Undeveloped	3,208.4	8.9	39.5	3,499.0	$1,018
Total Proved Reserves	4,825.3	19.2	75.8	5,394.9	$2,883

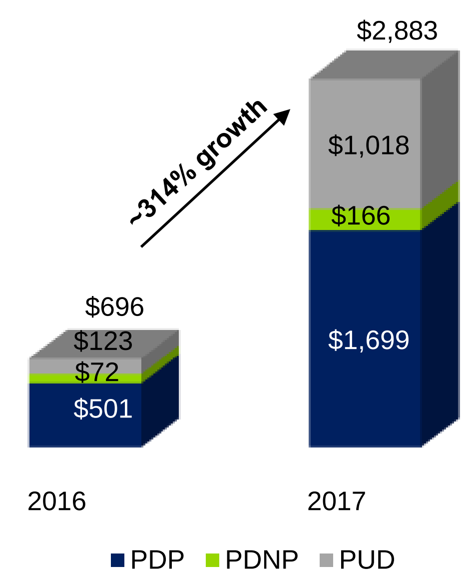
SEC NET PROVED RESERVES (BCFE)



SEC PROVED RESERVES BY ASSET AREA[1]



SEC 1P NET PRESENT VALUE – 10% ($MM)



1. Per Company reserve report for year ending 12/31/17.

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