RANGE RESOURCES®

Company Presentation
July 2019

Forward Looking Statements

All statements, except for statements of historical fact, made in this presentation regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements are based on assumptions and estimates that management believes are reasonable based on currently available information; however, management's assumptions and Range's future performance are subject to a wide range of business risks and uncertainties and there is no assurance that these goals and projections can or will be met. Any number of factors could cause actual results to differ materially from those in the forward-looking statements. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission (SEC), including its most recent Annual Report on Form 10-K. Unless required by law, Range undertakes no obligation to publicly update or revise any forward-looking statements to reflect circumstances or events after the date they are made.

The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as the option to disclose probable and possible reserves. Range has elected not to disclose its probable and possible reserves in its filings with the SEC. Range uses certain broader terms such as "resource potential," "unrisked resource potential," "unproved resource potential" or "upside" or other descriptions of volumes of resources potentially recoverable through additional drilling or recovery techniques that may include probable and possible reserves as defined by the SEC's guidelines. Range has not attempted to distinguish probable and possible reserves from these broader classifications. The SEC's rules prohibit us from including in filings with the SEC these broader classifications of reserves. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of actually being realized. Unproved resource potential refers to Range's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and have not been reviewed by independent engineers. Unproved resource potential does not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System and does not include proved reserves. Area wide unproven resource potential has not been fully risked by Range's management. "EUR", or estimated ultimate recovery, refers to our management's estimates of hydrocarbon quantities that may be recovered from a well completed as a producer in the area. These quantities may not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules. Actual quantities that may be recovered from Range's interests could differ substantially. Factors affecting ultimate recovery include the scope of Range's drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, actual drilling results, including geological and mechanical factors affecting recovery rates and other factors. Estimates of resource potential may change significantly as development of our resource plays provides additional data.

In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. Investors are urged to consider closely the disclosure in our most recent Annual Report on Form 10-K, available from our website at www.rangeresources.com or by written request to 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. You can also obtain this Form 10-K on the SEC's website at www.sec.gov or by calling the SEC at 1-800-SEC-0330.

Range – At a Glance

Unmatched Southwest Appalachia Inventory

- **Approximately one half million net acres provide decades of low-risk drilling opportunities**
- **Contiguous position allows for efficient operations and long-lateral development**
- **Peer-leading well costs and productivity underpin top-tier recycle ratio**
- **Proved Reserve Value (PV_{10}), net of debt, equals ~$24/share at year-end strip pricing**

Sustainable Free Cash Flow

- **Low maintenance capital requirements support free cash flow through the cycles**
- **Capital allocation process starts with free cash flow as a priority**
- **Cost structure improvements enhance margins and durability of free cash flow**

Leader on Sustainability and Environmental Practices

- **Long-lateral development minimizes operational footprint**
- **Industry-leading water-recycling program**
- **Emissions improved by 70% over the last three years**
- **First company to voluntarily disclose fracturing fluid for each completed well**

Unmatched Inventory in Southwest Appalachia

~3,700 undrilled core Marcellus wells [a] provide decades of low-risk drilling opportunities

<u>Marcellus</u> resource potential [b]

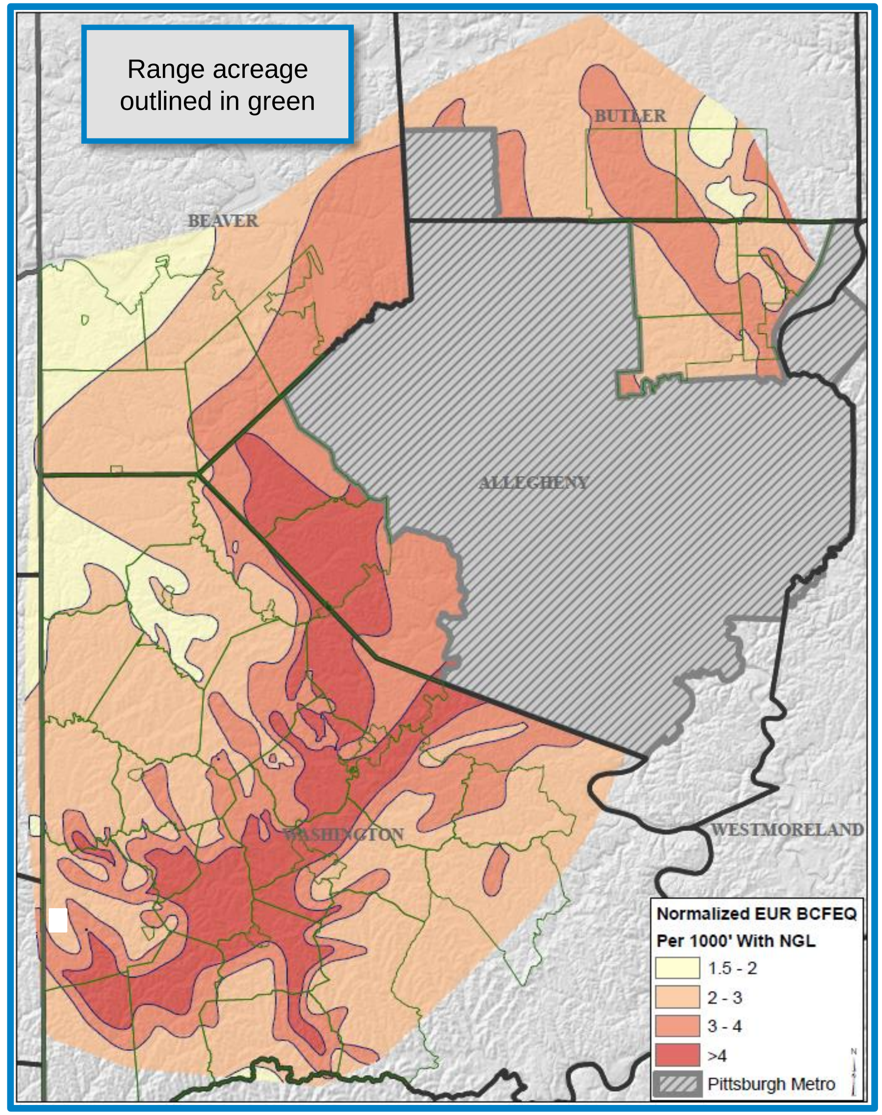
- ~ 40 Tcf of natural gas
- ~ 3 billion barrels of NGLs
- ~ 149 million barrels of condensate

Significant inventory of highly prolific Utica wells extends Range's dry gas opportunity

Existing natural gas and NGL infrastructure de-risks future development

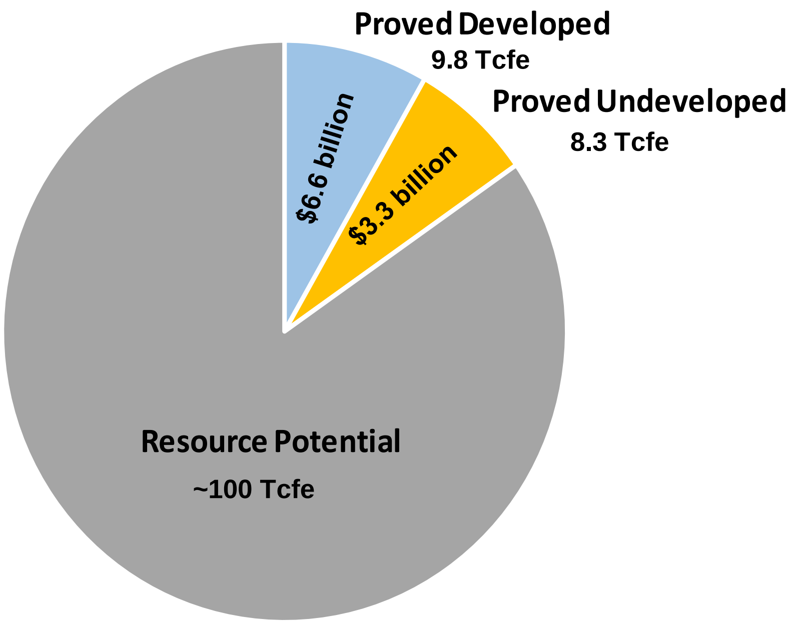
Contiguous acreage position provides for operational efficiencies and industry leading well costs:

- **Long-lateral development**
- **Efficient water handling and long-term infrastructure utilization**



(a) Estimates as of YE2018; based on production history from ~1,000 wells. Includes ~300 locations not shown on map. Based on 10,000 ft lateral length
(b) Does not include 18.1 Tcfe of YE2018 proved reserves.

Value of Year-end 2018 Proved Reserves - $24 per share



Included in Reserves, as defined by SEC

- Only 5 years of development activity
- Proved Developed reserves of 9.8 Tcfe with PV_{10} of $6.6 billion at YE18 strip
- Proved Undeveloped reserves of 8.3 Tcfe with PV_{10} of $3.3 billion at YE18 strip
- Approximately 400 Marcellus locations

Reserve Value Ignores Resource Potential

- Activity in years 6 and beyond
- Resource Potential of ~100 Tcfe
- Approximately 3,300 undrilled core Marcellus wells, or over 35 years of inventory at current drilling pace
- Potential from ~400,000 net acres of core Utica and ~500,000 net acres of Upper Devonian

Reserve History

- PUD Development Costs consistently better than Appalachia peers
- Positive performance revisions to reserves each year for the last decade

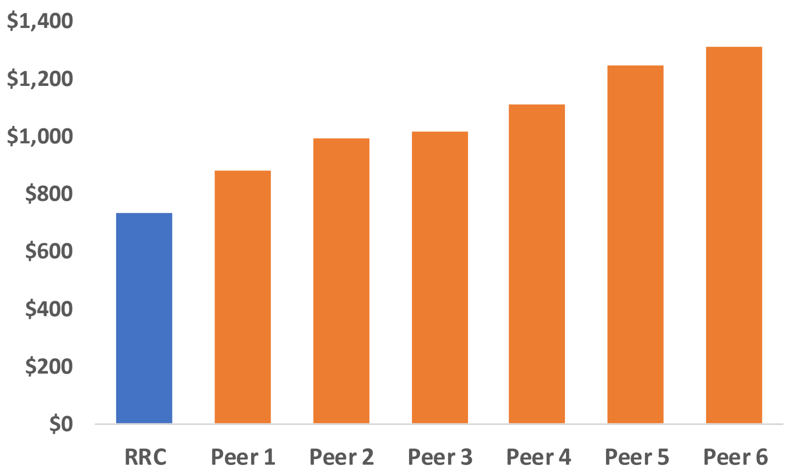
Note: PV-10 estimate assumes strip pricing. For reference, the 10-year average was $2.83/mmbtu NYMEX natural gas and $51.54/bbl WTI

Peer-Leading Development Costs

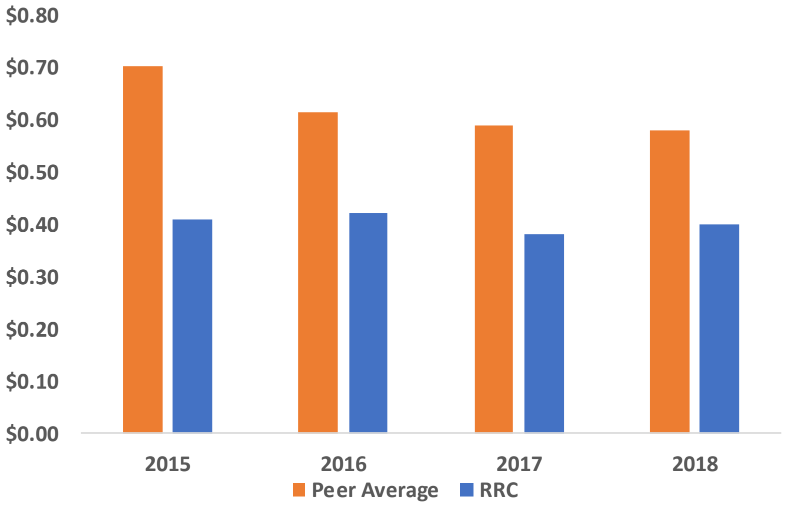
Blocked-up acreage allows for long laterals and efficient operations driving peer-leading well costs

Peer-leading well costs and recoveries result in top-tier development costs per mcfe

Appalachian Well Cost per Lateral Foot[(a)]

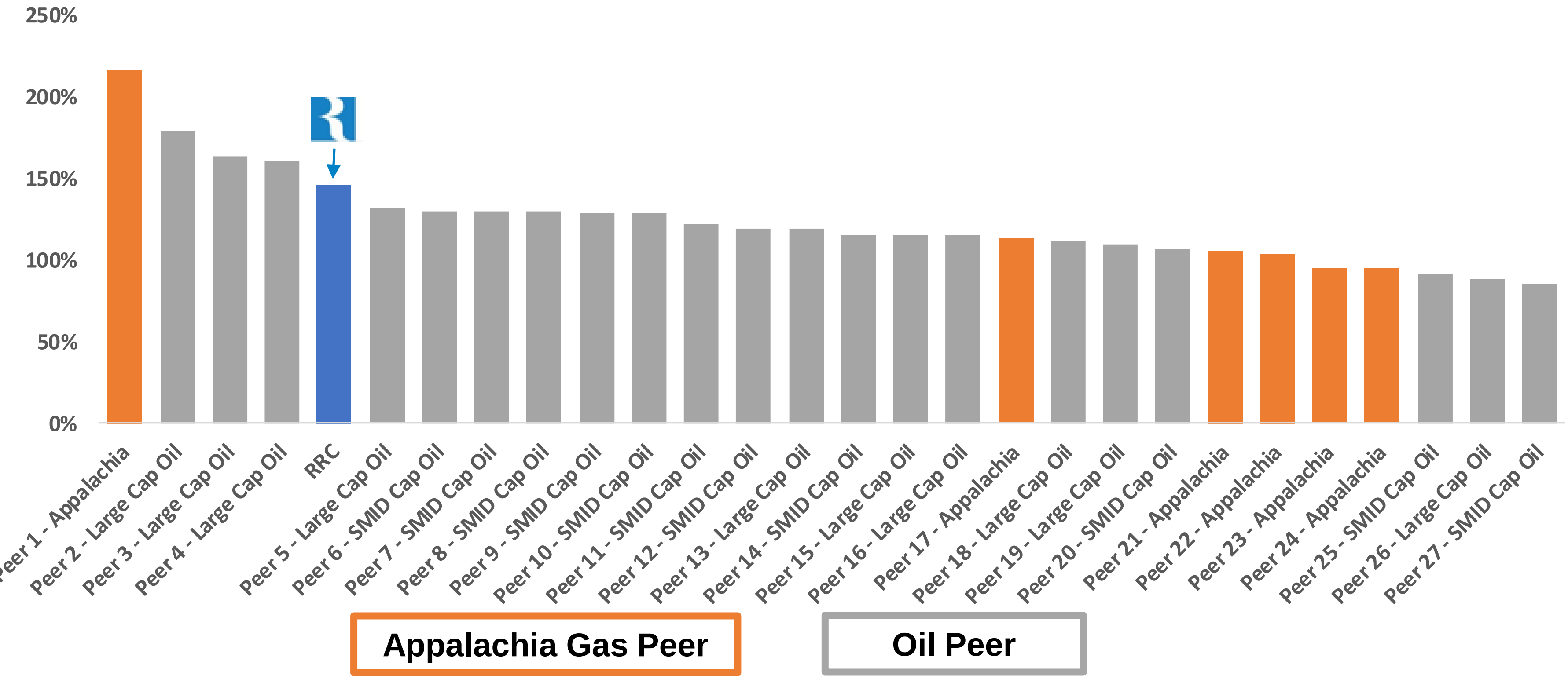


PUD Development Costs per Mcfe[(b)]



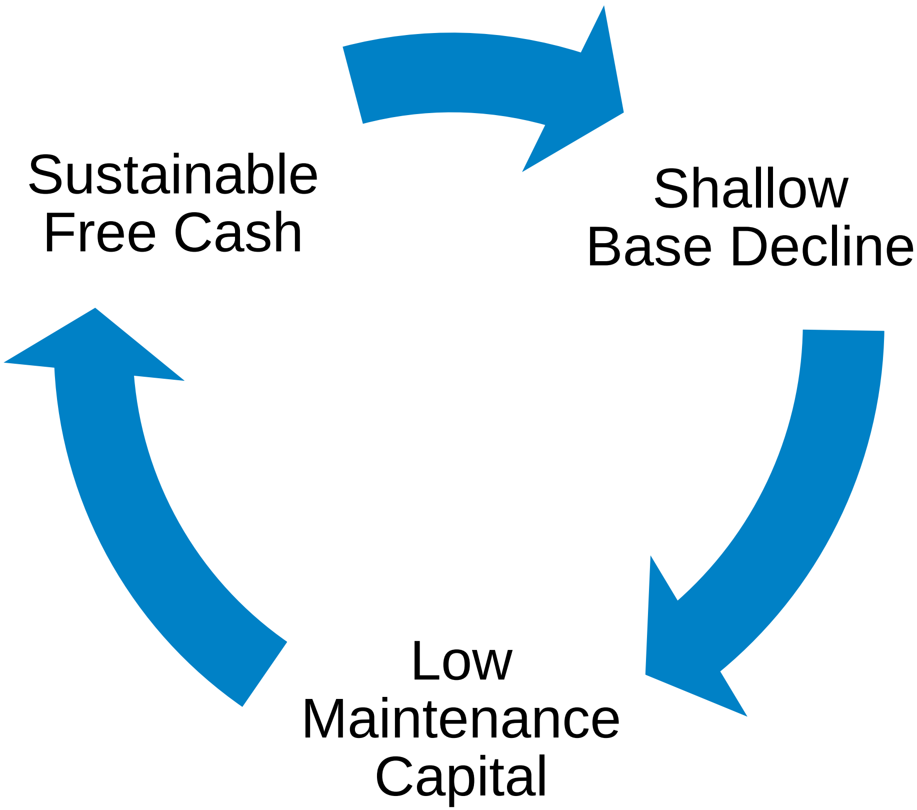
(a) Peers include AR, CNX, COG, EQT, GPOR and SWN. Peer estimates calculated based on operator guidance and statements for 2019.
(b) Peers include AR, CNX, COG, EQT, GPOR and SWN. SWN excluded from peer group in 2015 and 2016. PUD Development Costs defined as future development costs / PUD reserves.

Cash Recycle Ratio Shows Quality and Durability of Asset Base



Source: MKM Partners. "Energy/Exploration & Production Outlook". June 2019. Cash Recycle Ratio = Cash Operating Margin divided by Capital Intensity. Companies shown include APC, AR, CHK, CLR, CNX, COG, CRZO, CXO, DVN, ECA, EOG, EQT, GPOR, HES, HPR, LPI, MRO, MTDR, MUR, PDCE, PXD, SM, SRCI, SWN, WLL, WPX and XEC.

Maintenance Capital Drives Free Cash Flow Through the Cycles



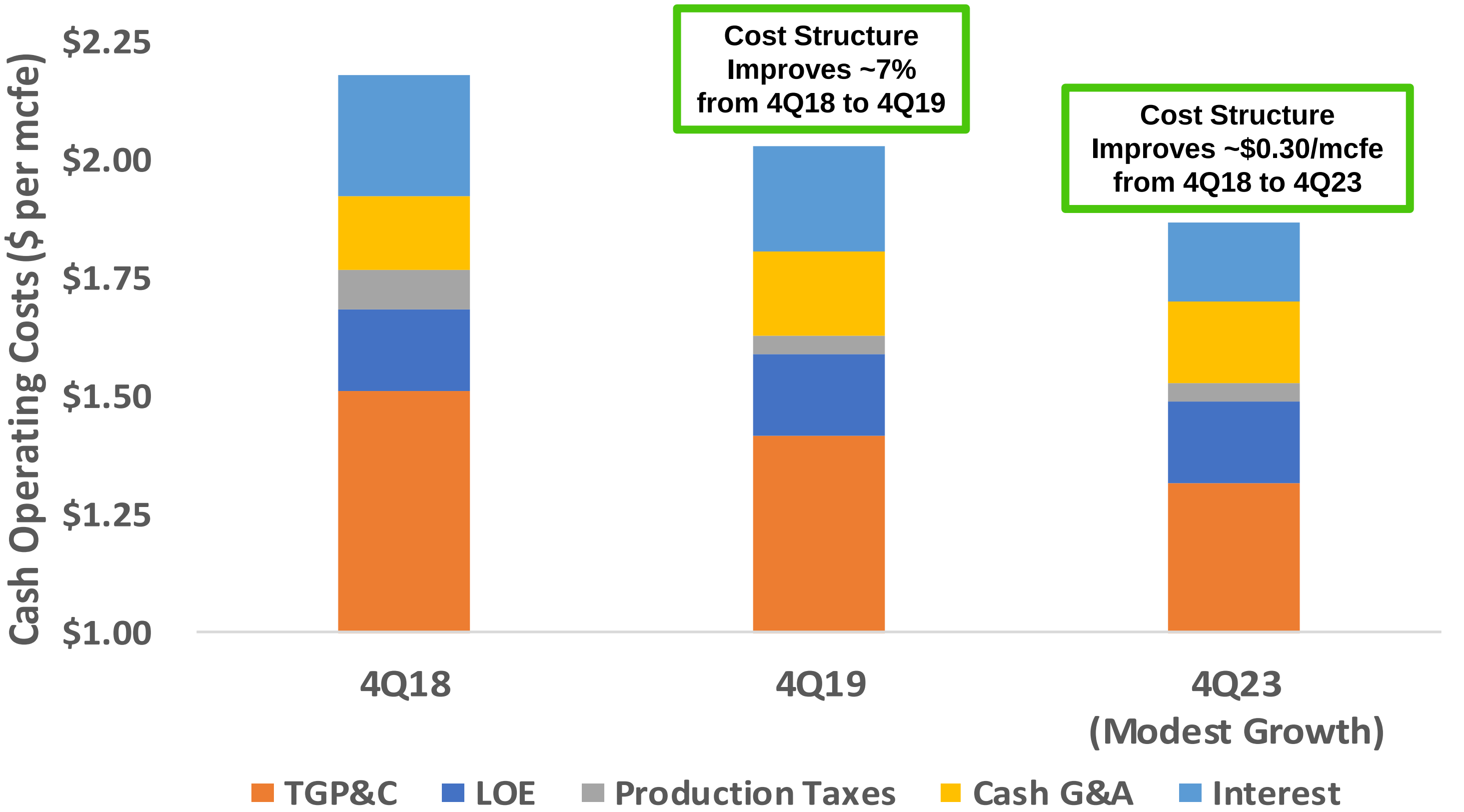
Shallow Base Decline Driven by:

- Core Marcellus position
- 10+ years of drilling in Marcellus provides solid base of low-decline wells
- Infrastructure built to maximize returns, not peak initial rates
- 2019 base decline rate of ~20% is sustainable, even with modest growth in base production
- Shallow base decline, coupled with efficient operations allows for low maintenance capital

Low Maintenance Capital Supports Sustainable Free Cash Flow

- Minimum capital requirements to maintain existing production levels compared to peers
- Generating free cash flow is priority in capital allocation process
- Free cash flow is durable given Range's multi-decade core Marcellus inventory

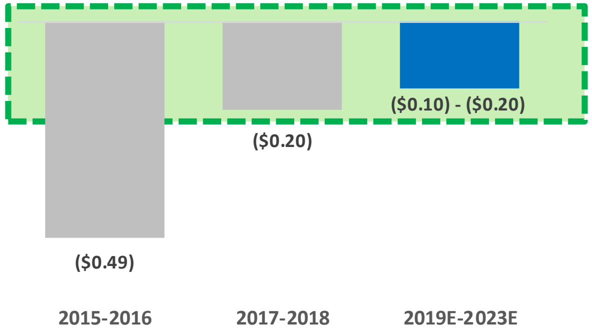
Improving Cost Structure Enhances Cash Flow & Margin Growth



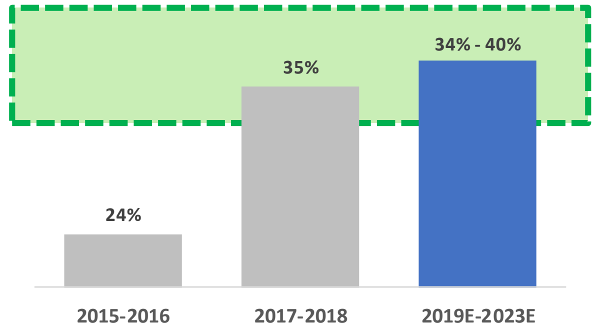
Cost structure improves as Range utilizes existing infrastructure, G&A declines and interest expense improves as free cash flow reduces debt

Differentials Have Stabilized and Improved vs Historical Levels

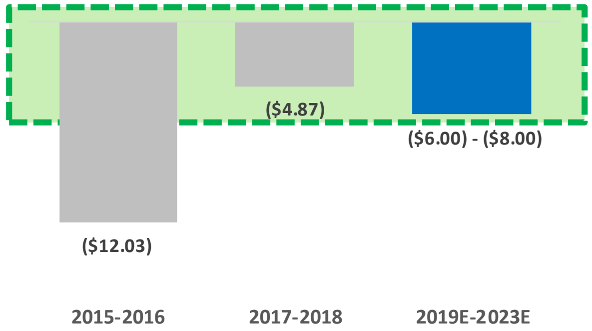
Natural Gas Differential[a]



NGL as a % of WTI[b]



Condensate Differential



Natural Gas

- Differentials stabilizing closer to NYMEX as pipeline transportation projects were completed in 2018, providing access to Midwest, Gulf Coast and Southeast markets
- With long-haul transport projects completed in 2018, TGC&P expense per mcfe expected to peak in 4Q 2018 before trending downward

Natural Gas Liquids

- Range has sent 20,000 barrels per day of ethane to Marcus Hook export facilities since early 2016 using Mariner East I
- Range is also sending propane and butane out of Marcus Hook, using a combination of pipe and rail.
- Beginning in 2020, Range expects to have Mariner East pipe capacity to move 40,000 barrels per day combined of propane and butane to export markets
- NGL fundamentals improve in 2H 2019

Condensate (Oil)

- 2018 oil price drove highest condensate realizations since 2014

(a) NG estimate includes basis hedges and is based on strip pricing at 4/12/19 (b) 2019E based on NGL strip pricing at 4/12/19. 2018 represents recent accounting change.

Corporate Sustainability Report Highlights

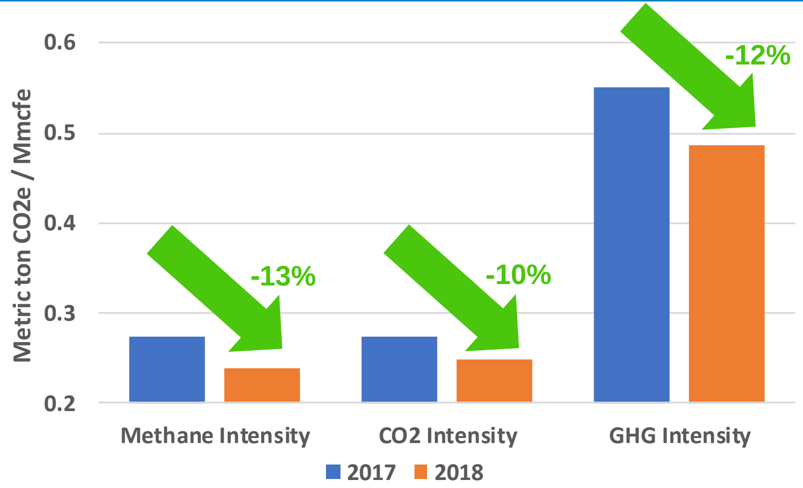
Emissions Target Across Operations

- **Range proactively works to optimize facility designs to reduce environmental footprint and improve production**
- **Design changes drove a ~12% reduction in greenhouse gas emissions per mcfe in 2018**
- **Ranked in the top tier of operators on methane emissions management and reporting by As You Sow, a nonprofit that promotes ESG-related shareholder advocacy**

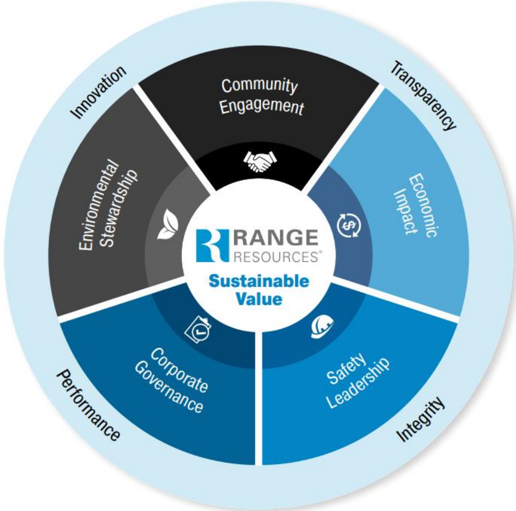
Industry Leader in Water Management

- **Range achieved a ~153% water recycle rate in Appalachia by recycling effectively all of Range's produced water as well as water from 10+ other operators through a Water Sharing Program**
- **Reduced total truck trips in Pennsylvania by more than 100,000 trips to locations in 2018 through new technologies and improved logistics**
- **Range's water management efforts provided capital savings in excess of $10 million for 2018 and improved LOE**

2018 Emission Reduction Results



Focus on Responsible ESG Practices



More information on Range's efforts regarding Environmental, Social and Governance issues can be found at the Sustainability page on the Company website.

Natural Gas Demand – Increases 21 Bcf/d in Next 5 Years

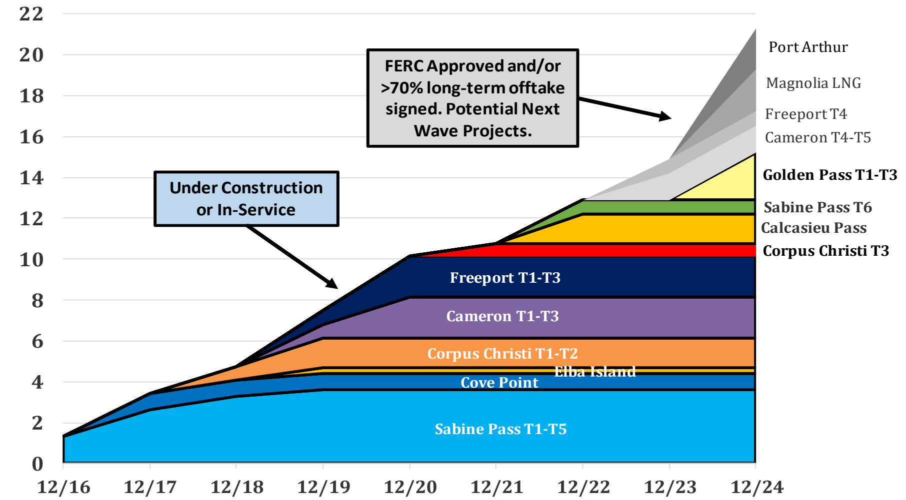
2019-2024 Demand Outlook

- **Total demand growth of +21 Bcf/d through 2024 from LNG and Mexican exports, industrial and electric power demand growth**
- **LNG export capacity to double by mid-2020 to 10 Bcf/d from projects under-construction**
- **Second Wave LNG Projects could add another +10 Bcf/d of exports by 2025**
- **Continued coal (currently ~30% of power stack) and nuclear retirements (~20% of power stack)**

U.S. LNG Export Demand Outlook

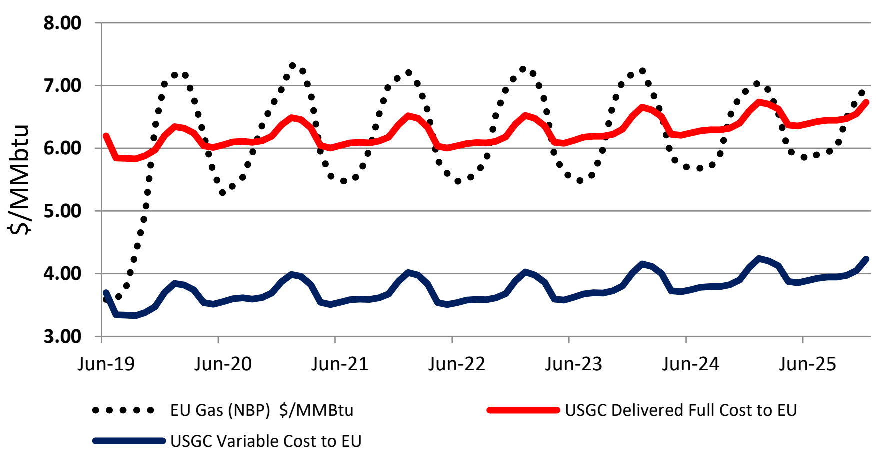
- **Second Wave of U.S. LNG Projects has started, with 5.1 Bcf/d already under-construction and another +5 Bcf/d likely to FID in 2019-2020**
- **Over 30 Bcf/d of Second-Wave LNG projects have been proposed**
- **Futures prices support additional LNG exports**
- **Range forecasts U.S. LNG export capacity to reach ~13 Bcf/d in 2022 and ~18 Bcf/d by late 2023-early 2024**

U.S. LNG Export Terminal Capacity (Bcf/d)



Source: EIA, LNG Operator announcements

Futures Market Indicates LNG Arb is OPEN



Bloomberg prices as of 6/12/19.

Natural Gas Supply - Base Decline & Capital Discipline

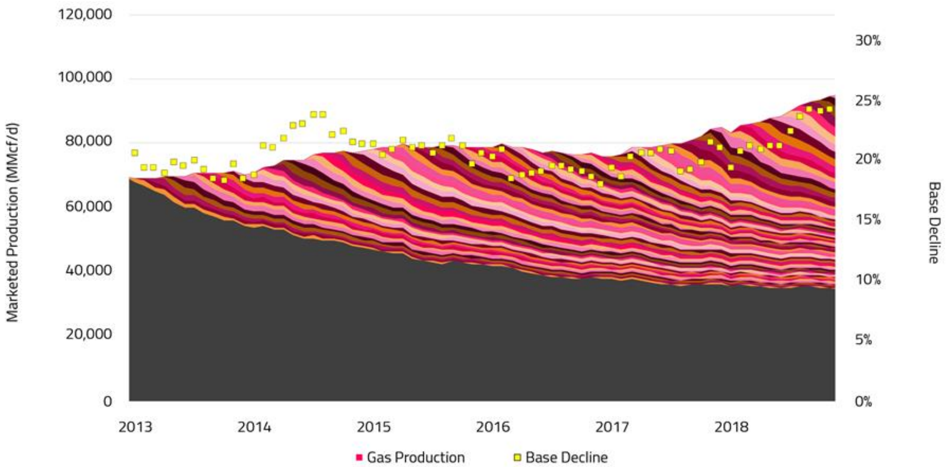
Base Declines Offset Current Activity

- Average U.S. decline rate of 24% equates to ~23 Bcf/d of new gas required to simply hold production flat
- U.S. decline rate likely increase given large ramp in 4Q18 TILs
- After drawing down DUCs, industry growth should slow meaningfully into exit 2019 and 2020 if strip prices hold
- Industry spending being limited to cash flow in 2019 makes base decline more difficult to offset

Producer Discipline Materially Impacts Supply Forecast

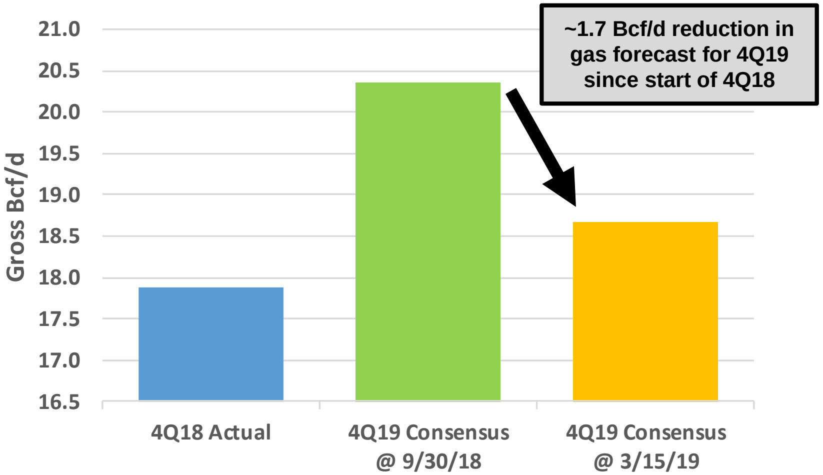
- Consensus 4Q19 gross gas estimates for Appalachia peer group (~65% of basin gas production) have been cut ~1.7 Bcf/d since start of 4Q18
- Consensus 4Q-4Q growth forecast now just ~4% (0.8 Bcf/d) for Appalachia peer group, significantly improving gas macro for late 2019 and 2020+
- Private Equity-backed operators may shift to a free cash flow model as traditional exit strategies become challenged (IPO, corporate M&A, etc.)

U.S. Natural Gas Base Decline Rate



Source: RS Energy

Consensus Gas Production for Appalachia Producers



Source: Bloomberg. Assumes average NRI of 80%. Appalachia producers include AR, CNX, COG, EQT, GPOR, RRC and SWN. SWN excludes Fayetteville.

NGL Macro Improving

New Infrastructure

Transitory Issues Impacting NGL Exports in 1Q19 Now Resolved

- **Approximately 200 MBPD in exports affected over 45 day period due to fog and ITC Tank Farm fire restricting Houston Ship Channel**

Fundamentals Set to Improve in 2H19

- **U.S. waterborne export capacity increases equivalent to ~15% of U.S. LPG supply, which should tighten balances going forward**
  - **2019 export capacity to increase by ~355 MBPD (Targa Galena Park, Enterprise Houston Ship Channel, Mariner East 2 / Marcus Hook) versus EIA gas plant LPG supply estimate of 2,381 MBPD at 4/30/19**

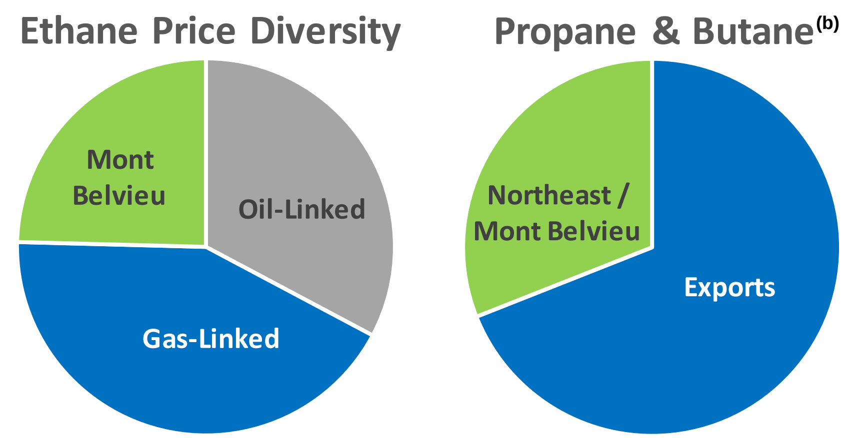
Storage and Supply

- **U.S. weekly propane YTD[(a)] production shows zero growth relative to December 2018 EIA weekly average. Export adjusted days of supply set a new 5-year low[(a)]**
- **NE propane storage >7% below last year on a 4-week moving average basis[(a)]**

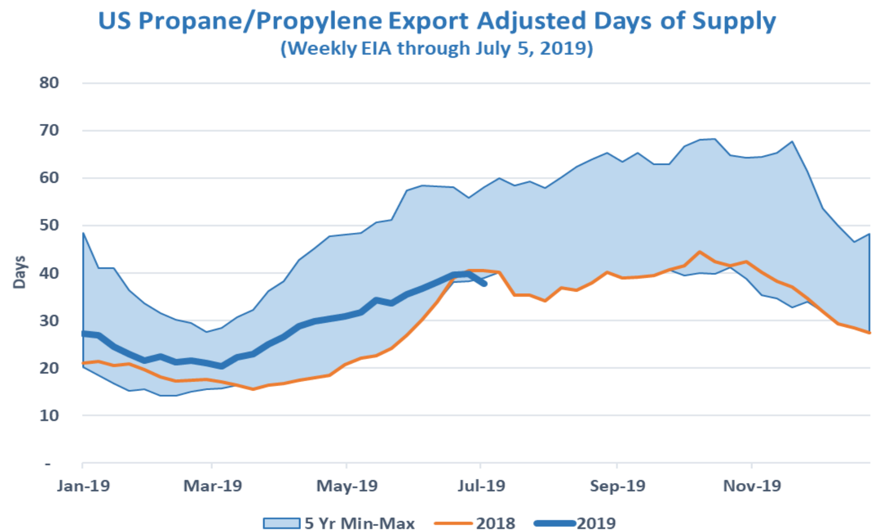
New Demand

- **3 PDH plants in China start up with combined capacity of 80 MBPD in 2019**
- **Indian LPG import terminals with capacity of 400 MBPD start up in 2019**
- **Relative economics support use of LPG over naphtha for international steam crackers**

Range's Ability to Export Provides Price Diversity



Propane Storage Based on Days of Supply



(a) As of 7/5/19. (b) Pie chart represents annual average. Range has the ability to increase domestic sales in winter months when local prices are strong.

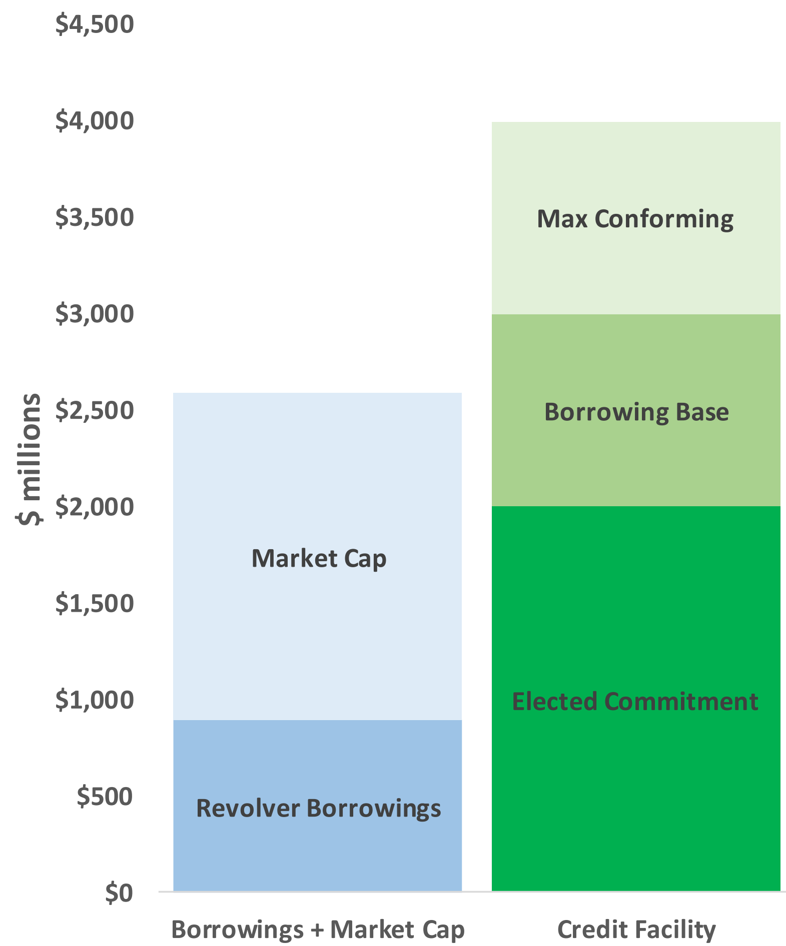
Range is Positioned Well for Low Commodity Prices

Self-Funded Business Model

- Range is growing, generating free cash flow and reducing absolute debt
- Flexible capital program as all of Range's firm transportation commitments have been met
- Shallow base decline supports low maintenance capital requirement
- Low maintenance capital and high capital efficiency promote free cash flow generation through the cycles
- Marcellus inventory enables multi-decade, sustainable free cash flow profile

Liquidity Exceeds Market Cap

- Ample liquidity given sustainable free cash flow profile
- $4B credit facility unanimously ratified in March 2019
- Revolver borrowings expected to be reduced via free cash flow generation and potential asset sales



Note: Revolver borrowings as of 3/31/19. Market capitalization as of 6/13/19.

RANGE RESOURCES

Appendix

Five-Year Outlook Assumptions

Assumptions:

- Production growth is driven by de-risked Marcellus inventory.
- Commodity Price Assumptions (strip pricing as of February 2019):
  - Henry Hub: $2.90 (2019), $2.70 (2020-2023)
  - Natural Gas Differential: $(0.14) in 2019, $(0.11) in 2020-2023
  - WTI: $57.50 (2019), $55 (2020-2023)
  - NGL: 37% of WTI (2019), 40% (2020-2023 average)
- Free cash flow used to reduce debt.
- Range is pursuing multiple asset sales, but no asset sales have been included in five-year outlook. Any additional asset sale proceeds would be used to accelerate timeframe for de-levering and returning capital to shareholders.
- Utica and Upper Devonian not considered in 5-year development outlook, though they provide thousands of additional drilling locations to Range inventory.
- Lateral lengths kept at 10,000 feet for calculating efficiencies.
- Additional efficiency gains from drilling and completion improvement and optimization are not included, though historical trends realized by the company would suggest this is possible.
- Capital savings from operational efficiencies assumed to be minimal.
- Minimal capital spent in North Louisiana.

Definitions:

Recycle ratio - ***Cash margin per mcfe / PUD development costs per mcfe. Example in Appendix***

Non-GAAP cash flow - ***Net cash from operations before changes in working capital***

Free cash flow - ***Non-GAAP cash flow minus total capital spending***

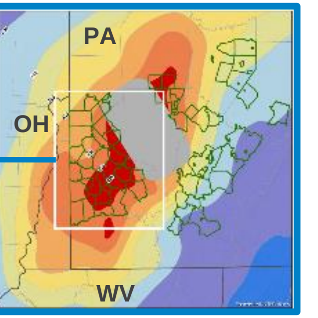
Free cash flow yield - ***Free cash flow / Market Cap.***

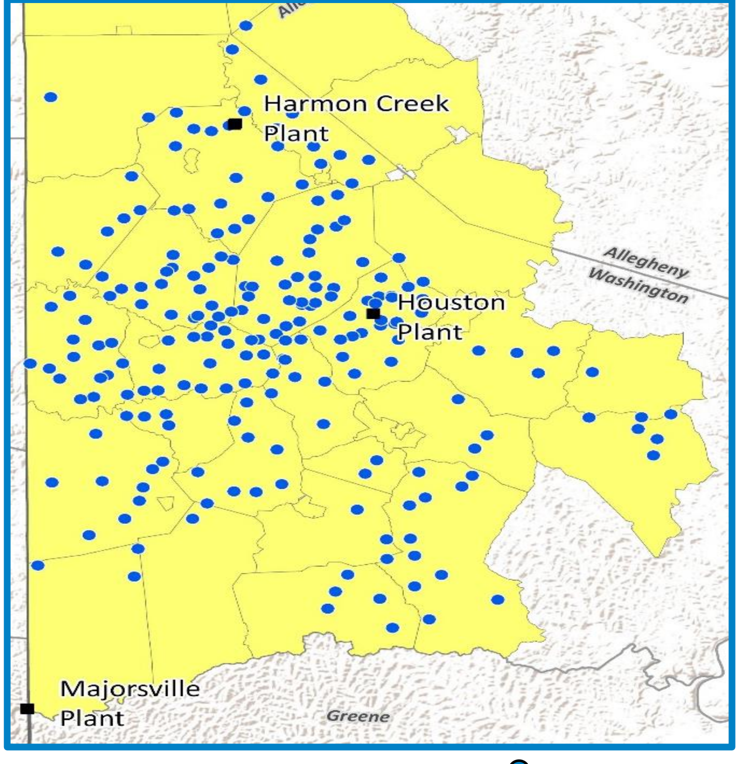
Maintenance capital - ***Estimated capital required to hold production flat from the previous year's exit rate***

Southwest Appalachia Acreage Position

- Longer laterals and existing pads in 2019 provide low-risk efficiency gains
- Liquids and dry optionality with existing pads across acreage position
- Concentrated acreage position simplifies water logistics and drives further cost savings, as Range continues to recycle ~100% of produced water

Note: Grey area is greater Pittsburgh area. Range acreage outlined in green.





= Existing Pad

Southwest Marcellus Economics

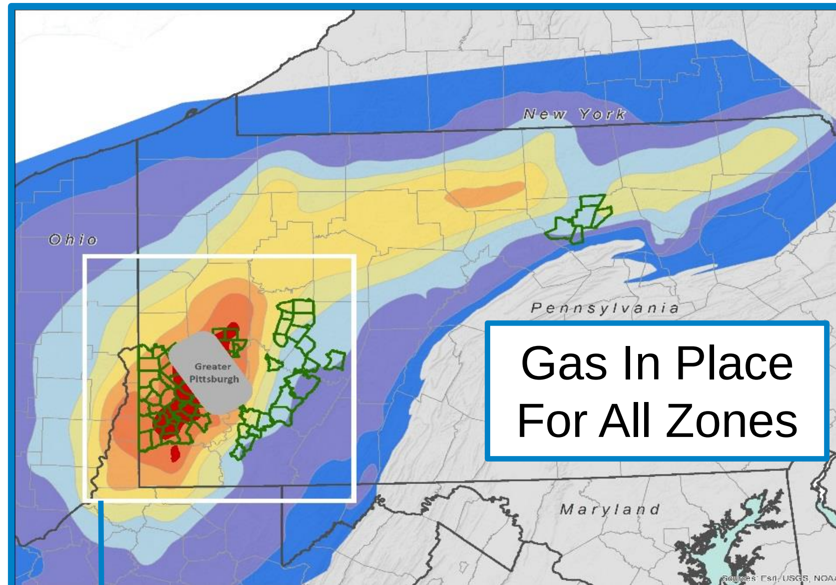
	Dry	Wet	Super-Rich
EUR	25.2 Bcf	29.6 Bcfe	26.0 Bcfe
EUR/1,000 ft. lateral	2.52 Bcf	2.96 Bcfe	2.60 Bcfe
Well Cost	$6.6 MM	$7.7 MM	$8.5 MM
Cost/1,000 ft. lateral	$661 K	$756 K	$845 K
Lateral Length	10,000 ft.	10,000 ft.	10,000 ft.
IRR* - $3.00	61%	69%	68%
IRR* at Strip as of 1/31/2019	46%	51%	52%

** Returns as of 1/31/19. For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl to life.*

Appalachia Assets – Stacked Pay

- ~1.5 million net effective acres [(a)] in PA leads to decades of drilling inventory
- Gas In Place analysis shows the greatest potential is in Southwest Pennsylvania
- Approximately 1,000 producing Marcellus wells demonstrate high quality, consistent results across Range's position
- Near-term activity led by Core Marcellus development in Southwest PA
- Range's Utica wells continue to produce strongly and our most recent well continues to be one of the best in the play
- Adequate takeaway capacity in Southwest PA

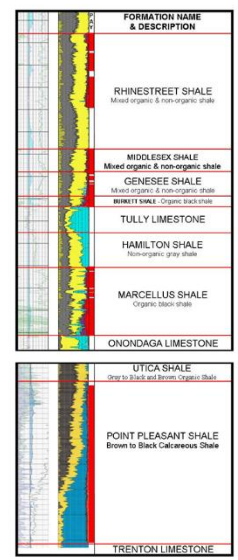
Stacked Pay and Existing Pads Allow for Multiple Development Opportunities



Upper Devonian

Marcellus

Utica/Point Pleasant



(a) Assumes stacked pay opportunities in Marcellus, Utica and Upper Devonian

Capital Allocation Scenarios – Five-Year Outlook Summary

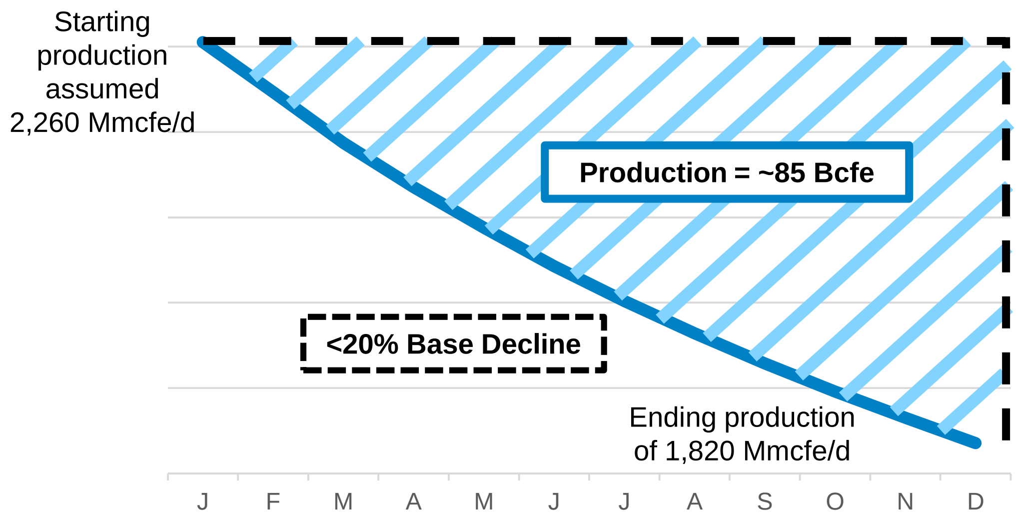
	Base Prices @ $2.70 gas/$55 WTI			Upside Prices @ $2.85 gas/$60 WTI
	Maintenance Capital	**Balanced Approach**	**Full Reinvestment**	**Balanced Approach**
2019-2023 Cumulative Free Cash Flow	$1.2-$1.3 billion	$1.2-$1.3 billion	$0	$2.0-$2.1 billion
Ending Net Debt (Year-End 2023)	$2.7-$2.8 billion	$2.7-$2.8 billion	~$4.0 billion	$1.9-$2.0 billion
Year-End 2023 Net Debt/EBITDAX	3.0x - 3.1x	2.0x - 2.1x	1.9x - 2.0x	1.1x - 1.2x
2023 Cash Unit Costs per Mcfe	$2.10 - $2.15	$1.87 - $1.92	$1.70 - $1.75	$1.85 - $1.90
Base Decline (Exit 2023)	<15%	<20%	~20%	<20%

As planned for 2019, a balanced approach towards capital allocation allows Range to decrease debt while improving unit costs and leverage.

FCF generation provides corporate optionality for uses of cash (share buybacks, dividends, etc.) after near-term leverage targets are realized.

Note: Five-year outlook projections assume midpoint of cost guidance and strip as of 2/22/19 in 2019, and $2.70/mmbtu natural gas and $55/bbl WTI in 2020-2024. Upside Case projections assume midpoint of cost guidance and strip as of 2/22/19 in 2019, and $2.85/mmbtu natural gas and $60/bbl WTI in 2020-2024. Additional assumptions on slide 17.

Maintenance Capital Example



1st year recoveries[a] for SW PA wells:

- Super Rich = 2.8 Bcfe gross (2.3 Bcfe net)
- Wet = 3.7 Bcfe gross (3.0 Bcfe net)
- Dry = 4.3 Bcf gross (3.5 Bcf net)

Simple Average: ~2.9 Bcfe net per well

Well Costs[a] for SW PA:

- Super Rich: $8.5 million
- Wet : $7.7 million
- Dry: $6.6 million

Average: $7.6 million cost per well

Blue-Sky Example[b]

- Average well contributes ~1.45 Bcfe net in calendar year if brought on mid-year under perfect conditions
- Production can be held flat with ~60 wells

  60 wells x 1.45 Bcfe recovery = ~85 Bcfe
- 60 wells x $7.6 average well cost = $455 million

~$455 million Maintenance D&C Capital

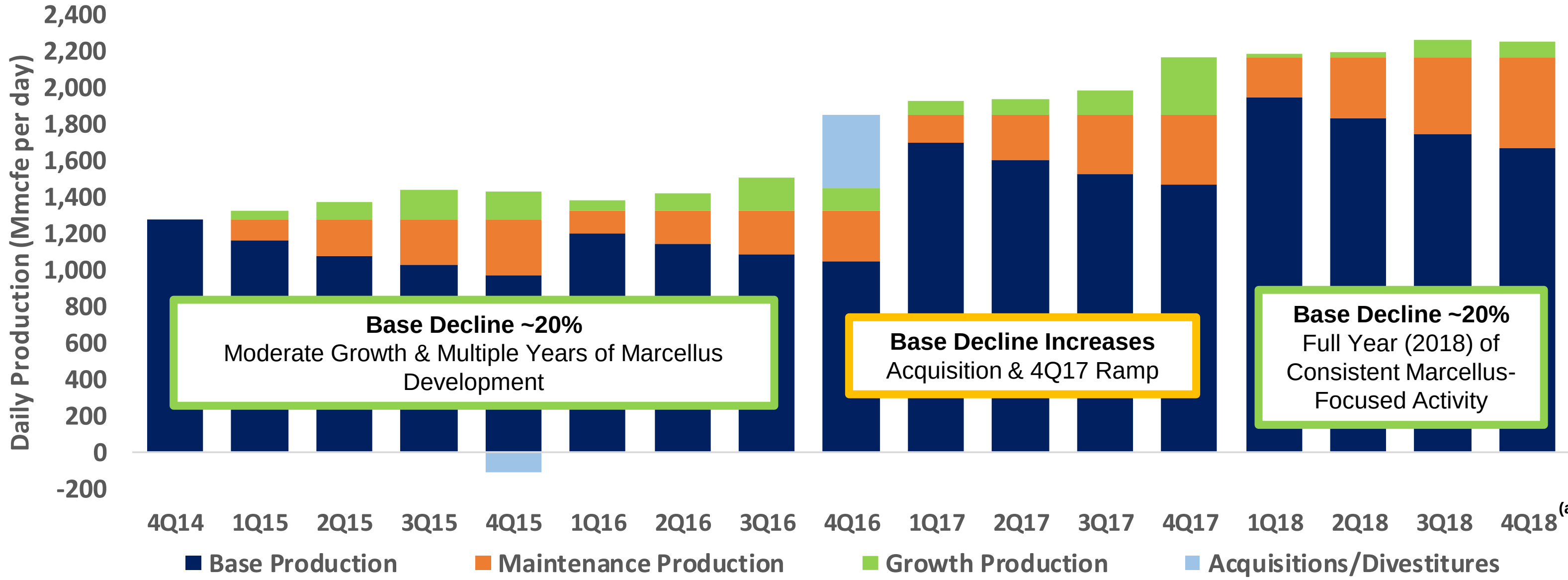
Typical Operating Adjustments[b]

- Considerations impacting annual development
  - Ethane flexibility
  - TIL allocation (wet vs. dry)
  - Timing of TILs
  - Maintenance
  - Weather

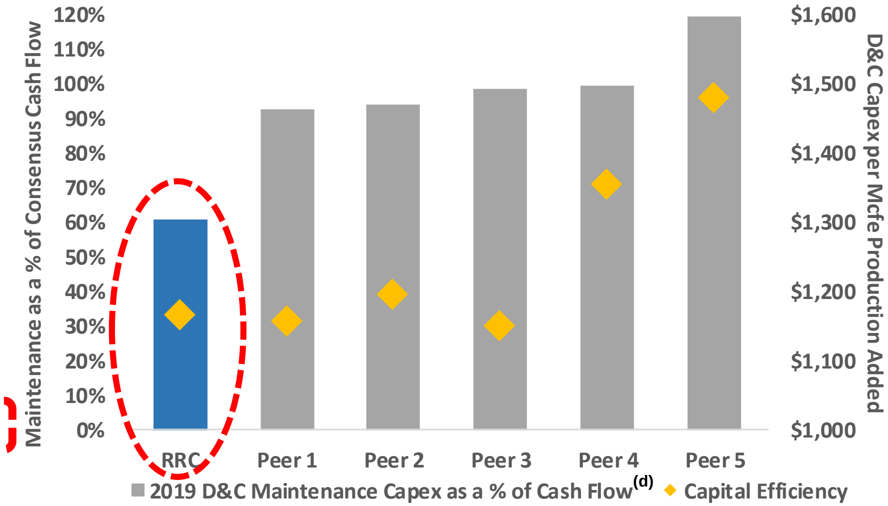
~$525 million Maintenance D&C Capital

(a) Assumes 10,000 ft. laterals (b) Assumes constant DUC inventory

Base Decline & Capital Efficiency Improving



	2015	2016	2017	2018	2019E
4Q Production (Mmcfepd)	1,435	1,854	2,170	2,260[a]	
Decline Rate from Prior Year 4Q		20%	24%	23%	~20%
4Q-4Q Base Decline (Mmcfepd)		287[b]	449	508	
4Q-4Q Growth (Mmcfepd)		129[c]	316	90	
Total Production Added (Mmcfepd)		416	765	597	
D&C Costs Incurred ($ millions)		$535	$1,180	$836	
D&C Capex per mcfe Production Added		**$1,286**	**$1,542**	**$1,399**	**~$1,200**



Note: Southwest Appalachia peers include AR, CNX, EQT, GPOR and SWN. (a) Includes 10 Bcfe of curtailments in 4Q18 from third-party processing downtime. (b) Pro-forma sale of Nora. (c) Pro-forma sale of Nora and excludes volumes added from North Louisiana acquisition. (d) Peer D&C maintenance capital and capital efficiency estimates based on company guidance and statements on 2019 decline rate. Consensus cash flow estimates as of 5/8/19, adjusted for capitalized G&A and interest.

SW PA Super-Rich Area Marcellus 2019 Well Economics

- Southwestern PA – (Wet Gas case)
- ~110,000 Net Acres
- EUR / 1,000 ft. – 2.6 Bcfe
- EUR – 26.0 Bcfe
  (360 Mbbls condensate, 1,999 Mbbls NGLs & 11.9 Bcf gas)
- Drill and Complete Capital $8.5 MM
  ($845 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.39/mcf

NYMEX Gas Price	Rate of Return
Strip -	52%
$3.00 -	68%

Estimated Cumulative Recovery for 2019 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	87	1,150	193
2 Years	122	1,949	328
3 Years	146	2,637	443
5 Years	179	3,791	637
10 Years	230	5,942	996
20 Years	291	8,683	1,460
EUR	360	11,890	1,999

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

SW PA Wet Area Marcellus 2019 Well Economics

- Southwestern PA – (Wet Gas case)
- ~240,000 Net Acres
- EUR / 1,000 ft. – 2.96 Bcfe
- EUR – 29.6 Bcfe
  (80 Mbbls condensate, 2,440 Mbbls NGLs & 14.5 Bcf gas)
- Drill and Complete Capital $7.7 MM
  ($756 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.31/mcf

NYMEX Gas Price	Rate of Return
Strip -	51%
$3.00 -	69%

Estimated Cumulative Recovery for 2019 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	29	1,737	292
2 Years	43	2,890	486
3 Years	52	3,823	644
5 Years	63	5,300	892
10 Years	73	7,849	1,321
20 Years	78	10,982	1,849
EUR	80	14,491	2,440

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

SW PA Dry Area Marcellus 2019 Well Economics

- Southwestern PA – (Dry Gas case)
- ~150,000 Net Acres
- EUR / 1,000 ft. – 2.52 Bcf
- EUR – 25.2 Bcf
- Drill and Complete Capital $6.6 MM
  ($661 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.32/mcf

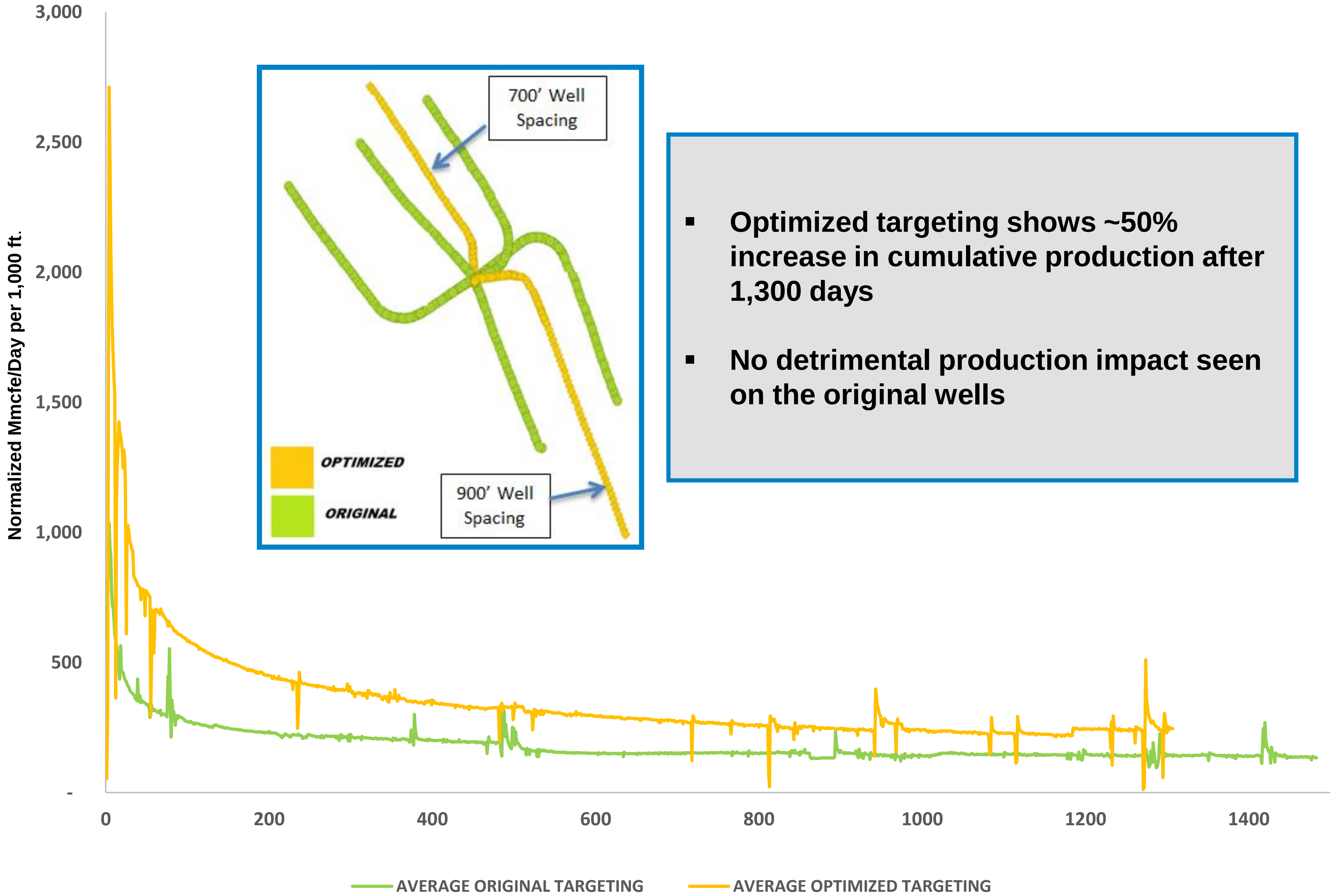
NYMEX Gas Price	Rate of Return
Strip -	46%
$3.00 -	61%

Estimated Cumulative Recovery for 2019 Production Forecast	Residue (Mmcf)
1 Year	4,341
2 Years	6,677
3 Years	8,379
5 Years	10,870
10 Years	14,846
20 Years	19,487
EUR	25,199

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

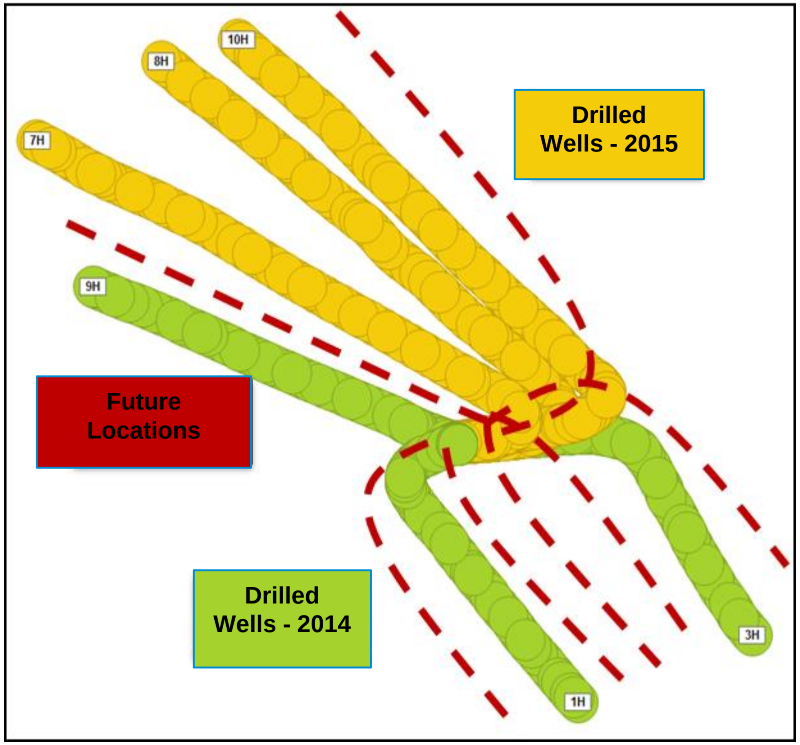
Based on Washington County well data

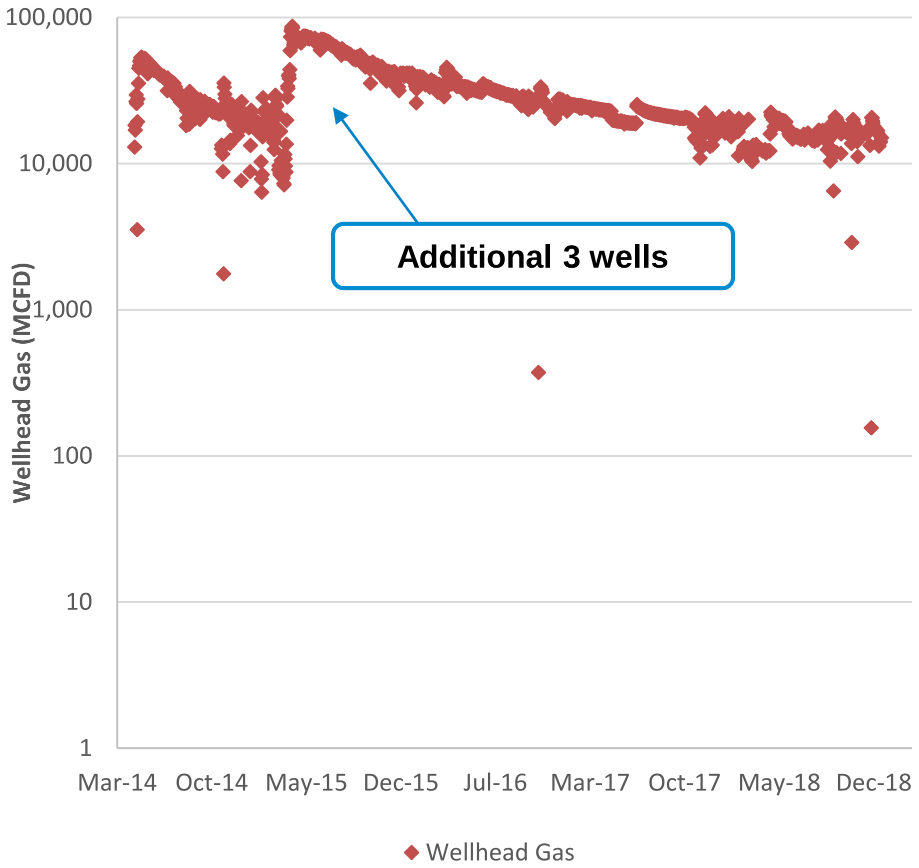
Targeting / Downspacing Production Results



- **Optimized targeting shows ~50% increase in cumulative production after 1,300 days**
- **No detrimental production impact seen on the original wells**

Return to Existing Pads – Marcellus



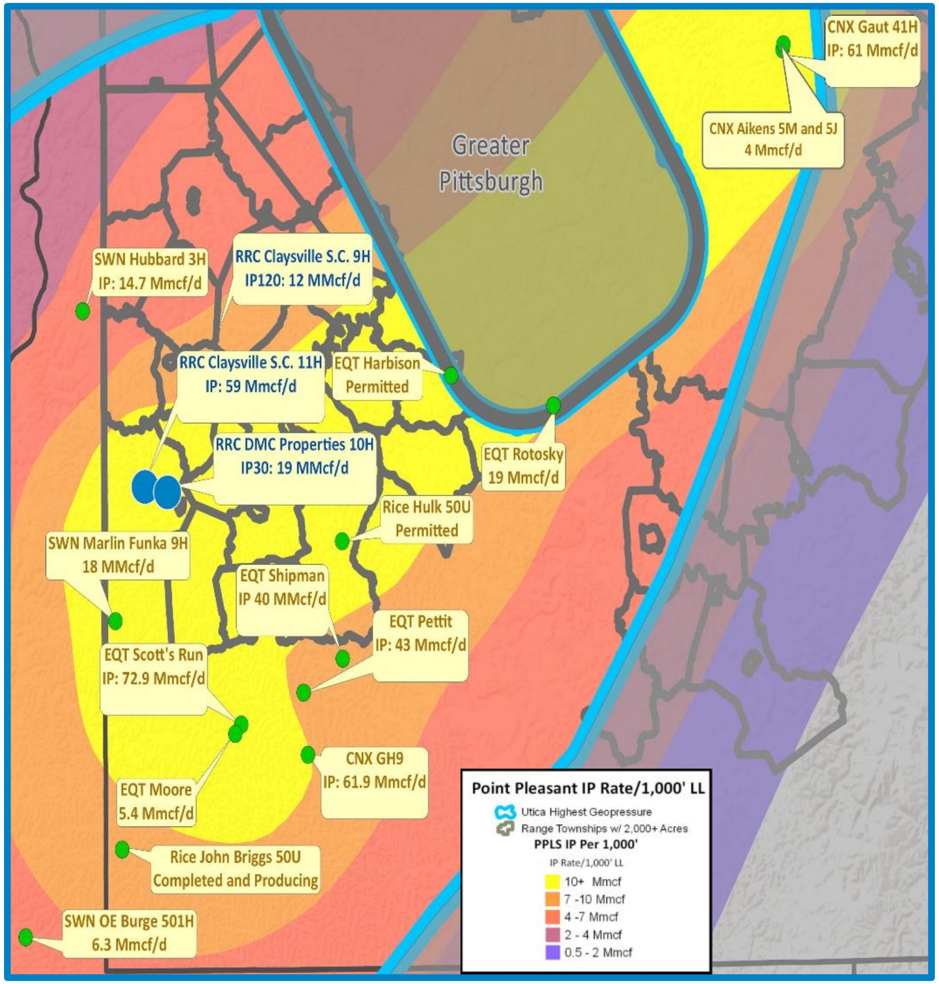


Ability to target our best areas with significant cost savings

Utica Activity

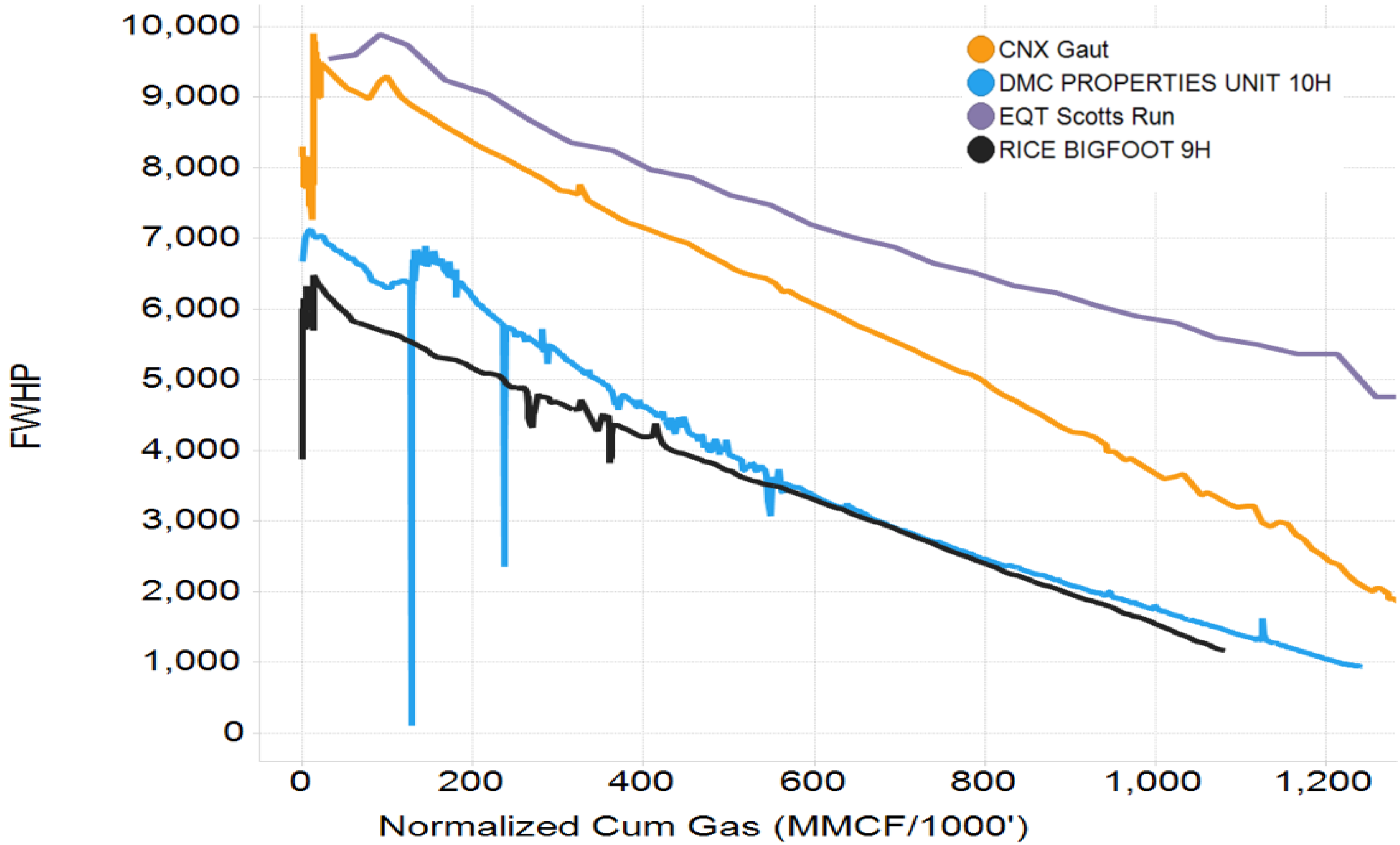
- Range has drilled three Utica wells
- Range's third well appears to be one of the best dry gas Utica wells in the basin (next slide)
- Continued improvement in well performance due to higher sand concentration and improved targeting
- 400,000 net acres in SW PA prospective

The Industry Continues to Delineate the Utica around Range's Acreage



Note: Townships where Range holds ~2,000+ or more acres are shown outlined above

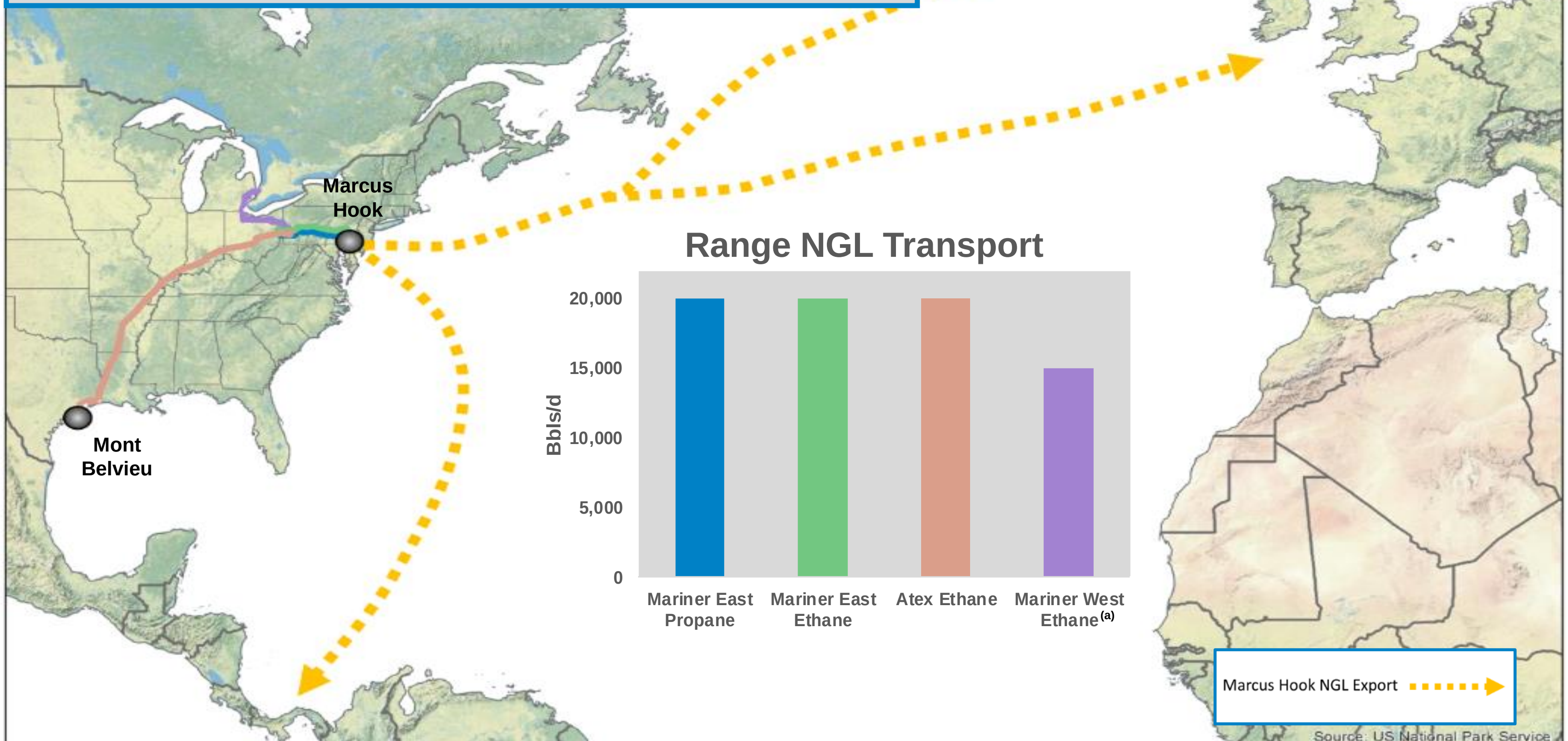
Utica Wells – Wellhead Pressure vs. Cumulative Production



Range's DMC Properties well one of the best in the Utica

Innovative NGL Marketing Agreements Enhance Pricing

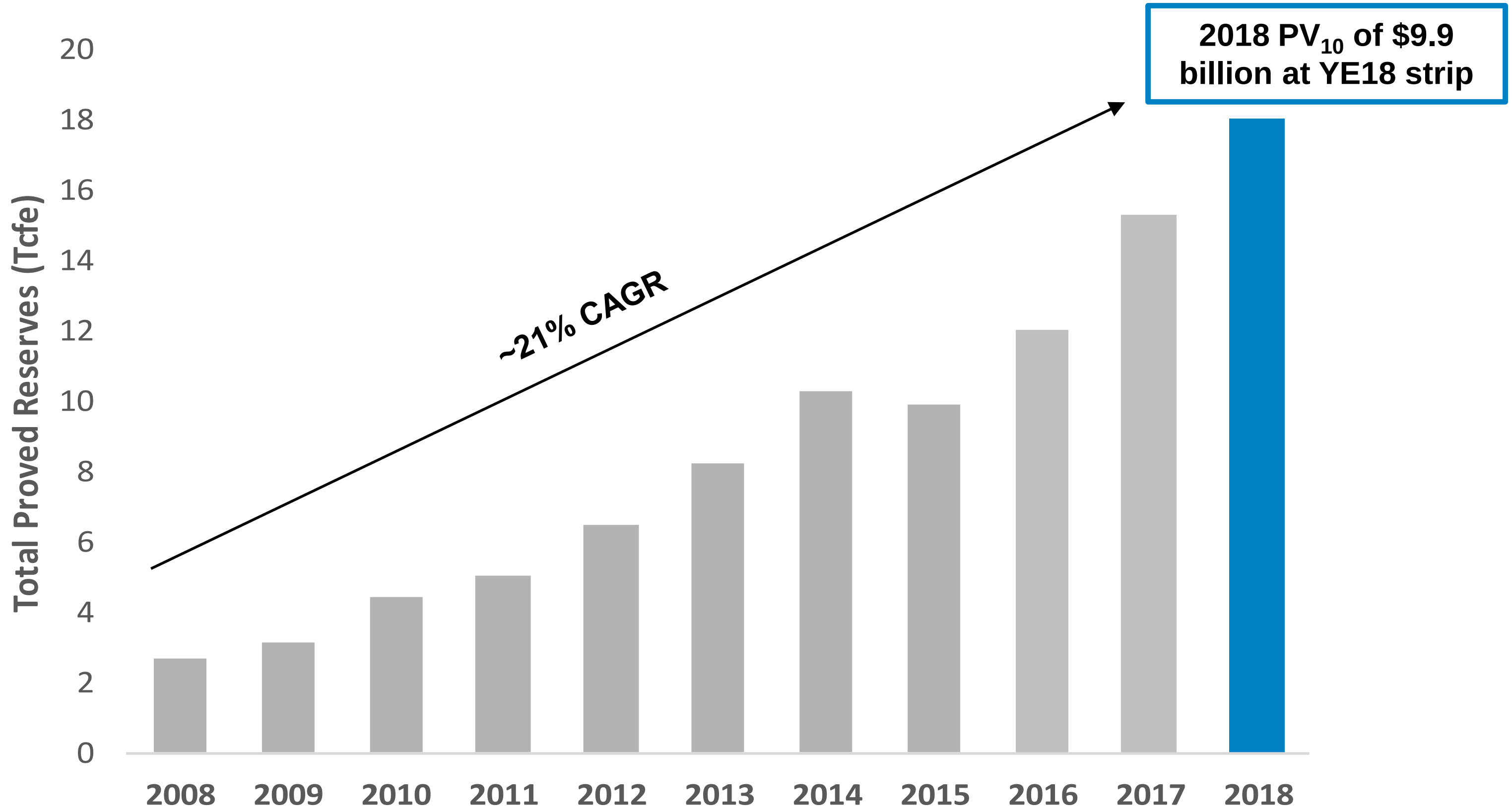
- First-mover on Appalachian NGL exports to Europe via ethane sales to INEOS using Mariner East capacity
- Range’s propane has been sold internationally since 2016 through Marcus Hook, with option to sell into premium NE winter markets
- Mariner West ethane sent to Nova Chemical (Canada)
- ATEX moves Appalachia ethane to the Gulf Coast (Mont Belvieu)



(a) FOB Houston Plant

Consistent Track Record of Reserve Growth

- Proved reserves of 18.1 Tcfe as of year end 2018
- YE18 proved reserves increased ~18% y/y
- Future development costs for proved undeveloped reserves are estimated to be $0.40 per Mcfe at YE2018



Positive Performance Revisions for Last Decade Indicate Quality of Reserves

RANGE RESOURCES®

Natural Gas & NGL Macro Outlook

Natural Gas - 35% of the U.S. Generation Mix in 2018

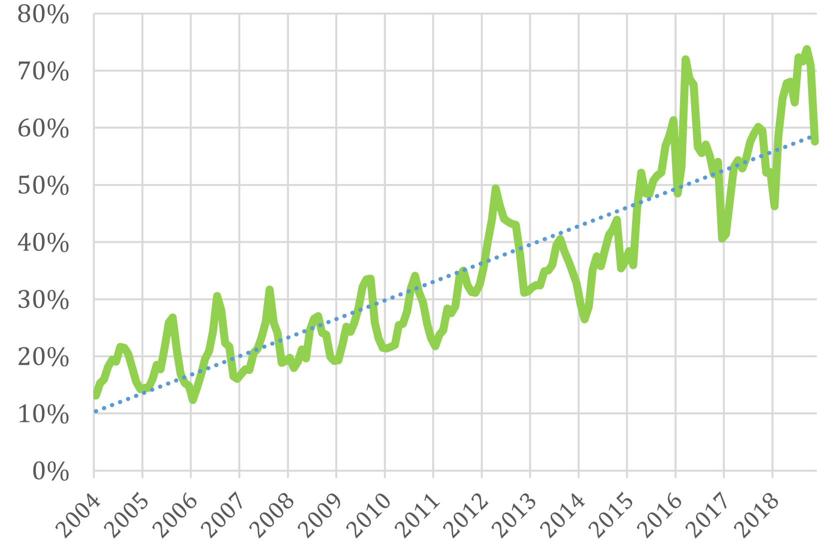
Growing Market Share in Power Gen.

- Gas power demand grew by 11 Bcf/d from 2009-2018, while coal declined 11 Bcf/d[(a)] and renewables grew 5.3 Bcf/d[(a)]

Market Share Growth Should Continue

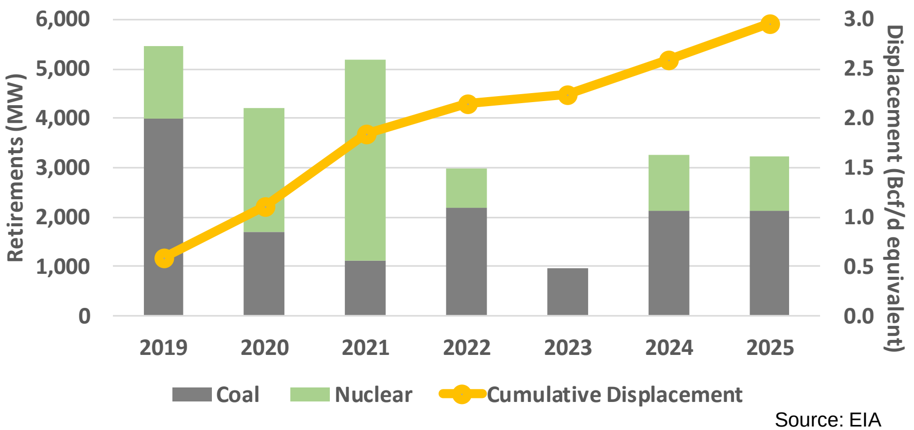
- 25 Bcf/d of coal generation remains to be displaced, or ~27% of U.S. Power Generation Mix
- 53 GW of coal plant capacity retired from 2013-2018, and another 12 GW of plant retirements have already been announced for 2019-2024
  - More retirement announcements expected to occur in coming months/years
- Planned nuclear retirements also remove large base-load of power generation
- New gas-fired reciprocating engines being added to balance grid instability issues created by renewables

U.S. Natural Gas Generation as a % of Gas + Coal



Source: EIA

Announced Coal & Nuclear Reactor Retirements



Source: EIA

(a) Assumes 7x Heat Rate for gas equivalence

Shale Efficiency Gains Are Slowing

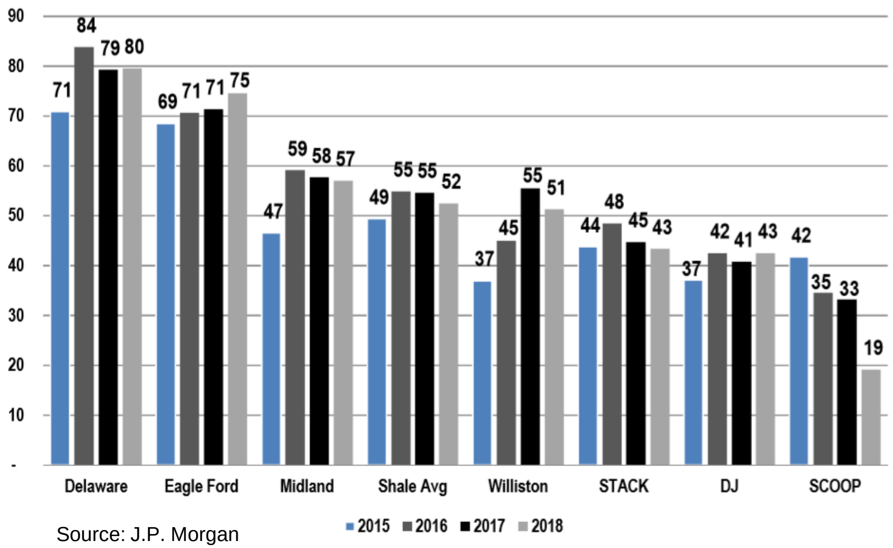
Oil Basins

- Limited Tier-1 runway left in Williston and Eagle Ford as cores are believed to have been heavily drilled
- Up-spacing across several plays reduces core inventory life
- Efficiency gains from lateral length and proppant intensity now seeing diminishing returns versus 3 years ago
- Parent-Child issues becoming more prevalent as child wells produce materially less than parent wells

Haynesville

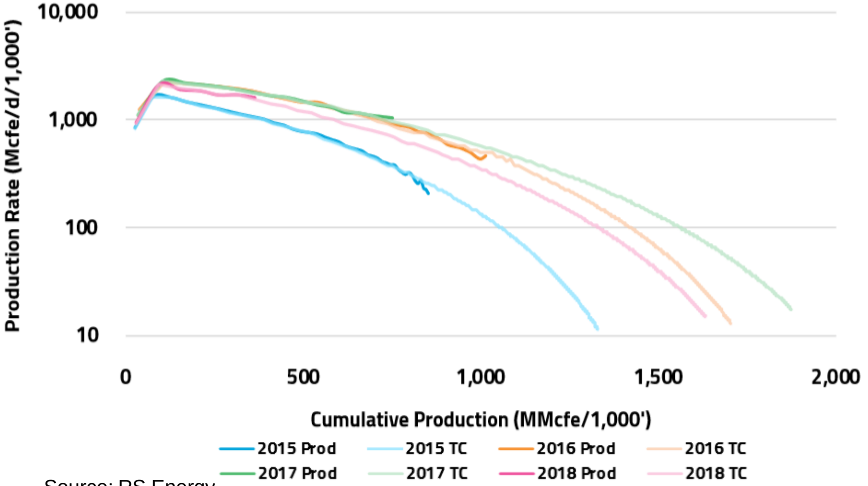
- Well productivity in the Haynesville appears to have plateaued
- Runway for current productivity may be limited given current pace of development in the play and that the core is known to be small
- Private operators may be forced to reduce growth as traditional exit strategies have become challenged

6-Month Daily Oil Production per 1,000 Lateral Ft.



Source: J.P. Morgan

Haynesville Production per 1,000 Lateral Ft.



Source: RS Energy

Dry Gas Basin Economics Under Pressure at Current Strip

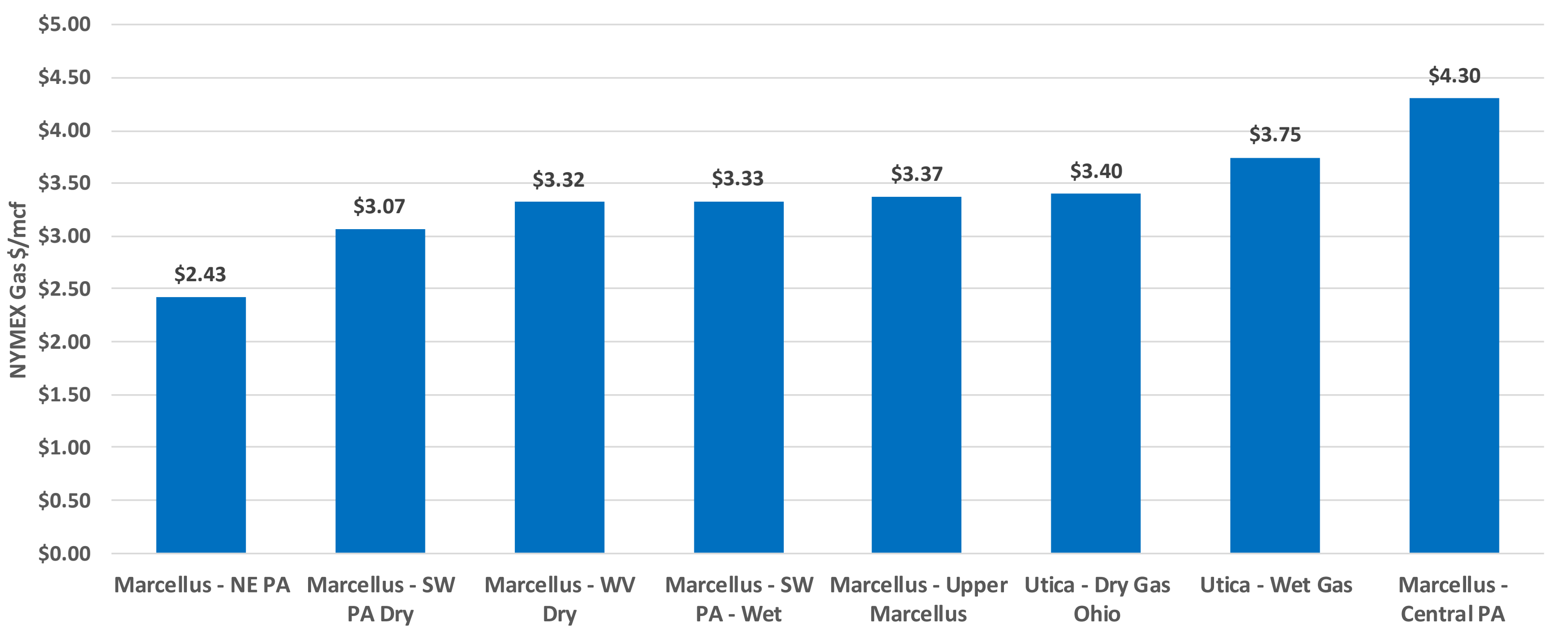
Supply Growth Needed from Dry Gas Basins

- **EIA forecasts 6.7 Bcf/d of 2019-2024 supply growth from outside of Northeast (mostly associated gas)**
- **Demand growth forecast of +21 Bcf/d from 2019-2024 will require growth from dry gas basins to balance market**

Higher-Than-Strip Prices Will Be Needed to Support Dry Gas Basin Growth

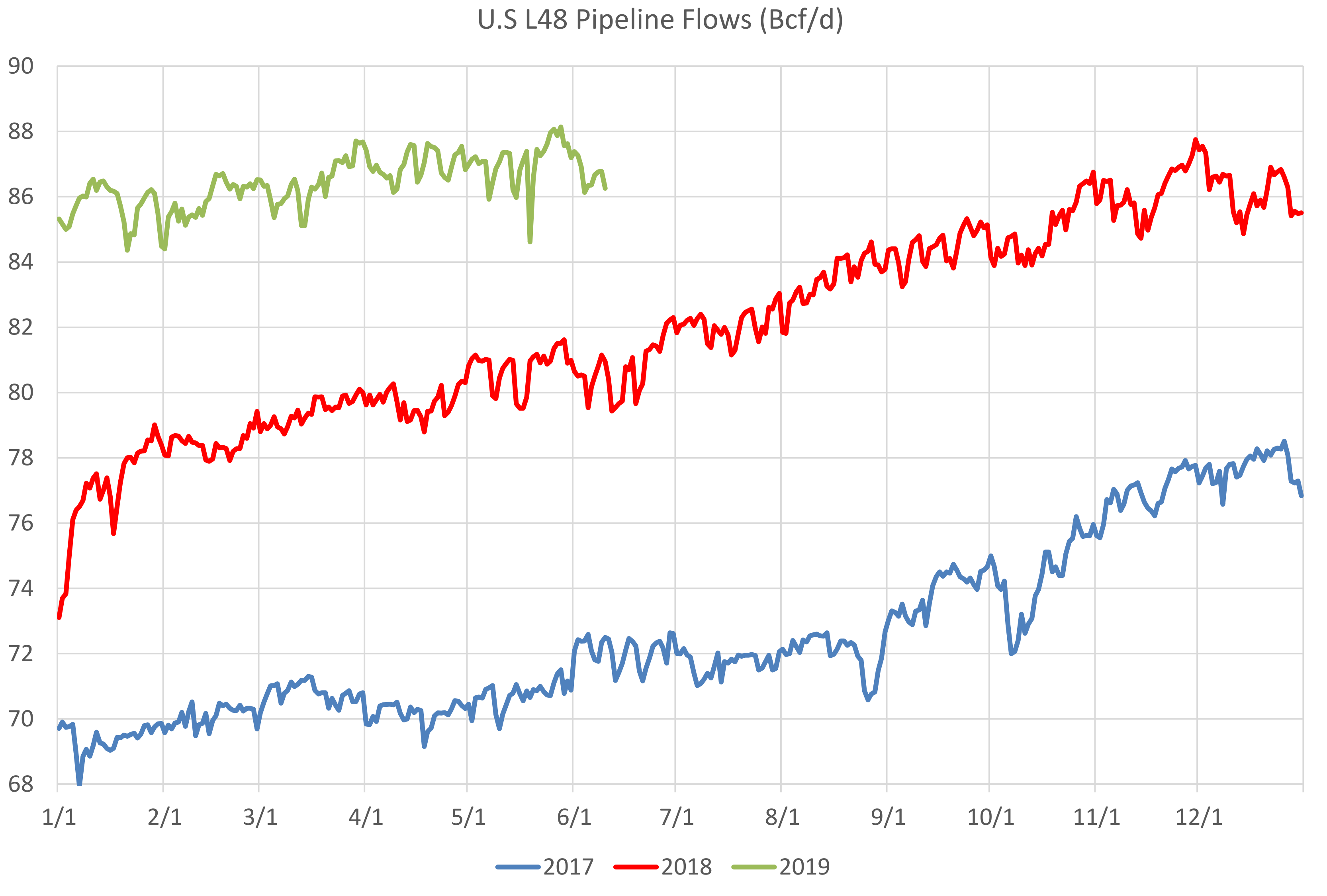
- **Northeast PA will face constraints to growing beyond 2-3 Bcf/d given current lack of infrastructure**
- **Dry gas basins likely require >$3/Mmbtu natural gas to support sustainable growth**

Basin Break-Evens Above NYMEX Futures Curve



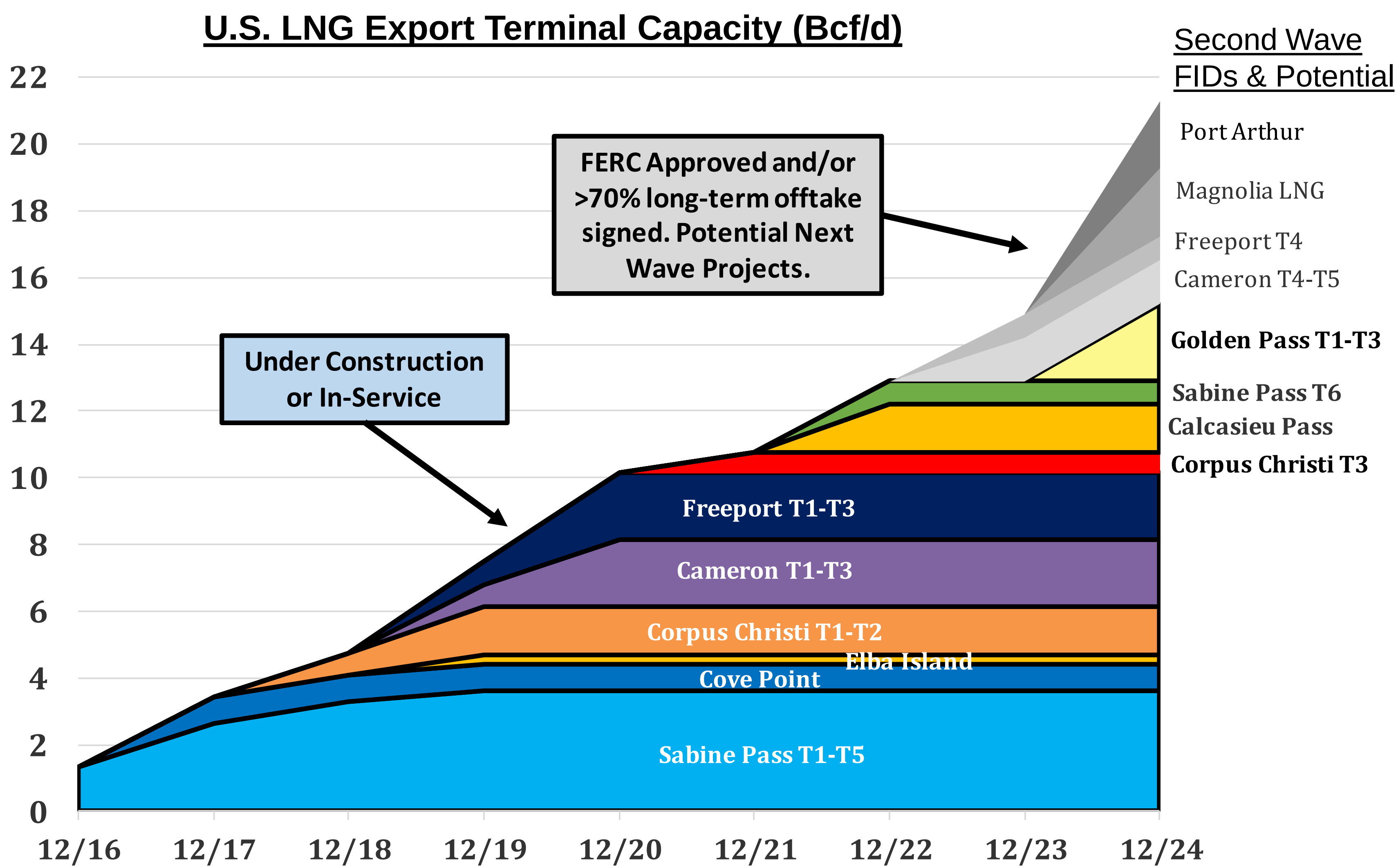
Source: J.P. Morgan. Break-evens assume 25% pre-tax full-cycle rate of return to account for corporate G&A, interest expense and acreage costs.

L48 Dry Gas Production Growth Slowing



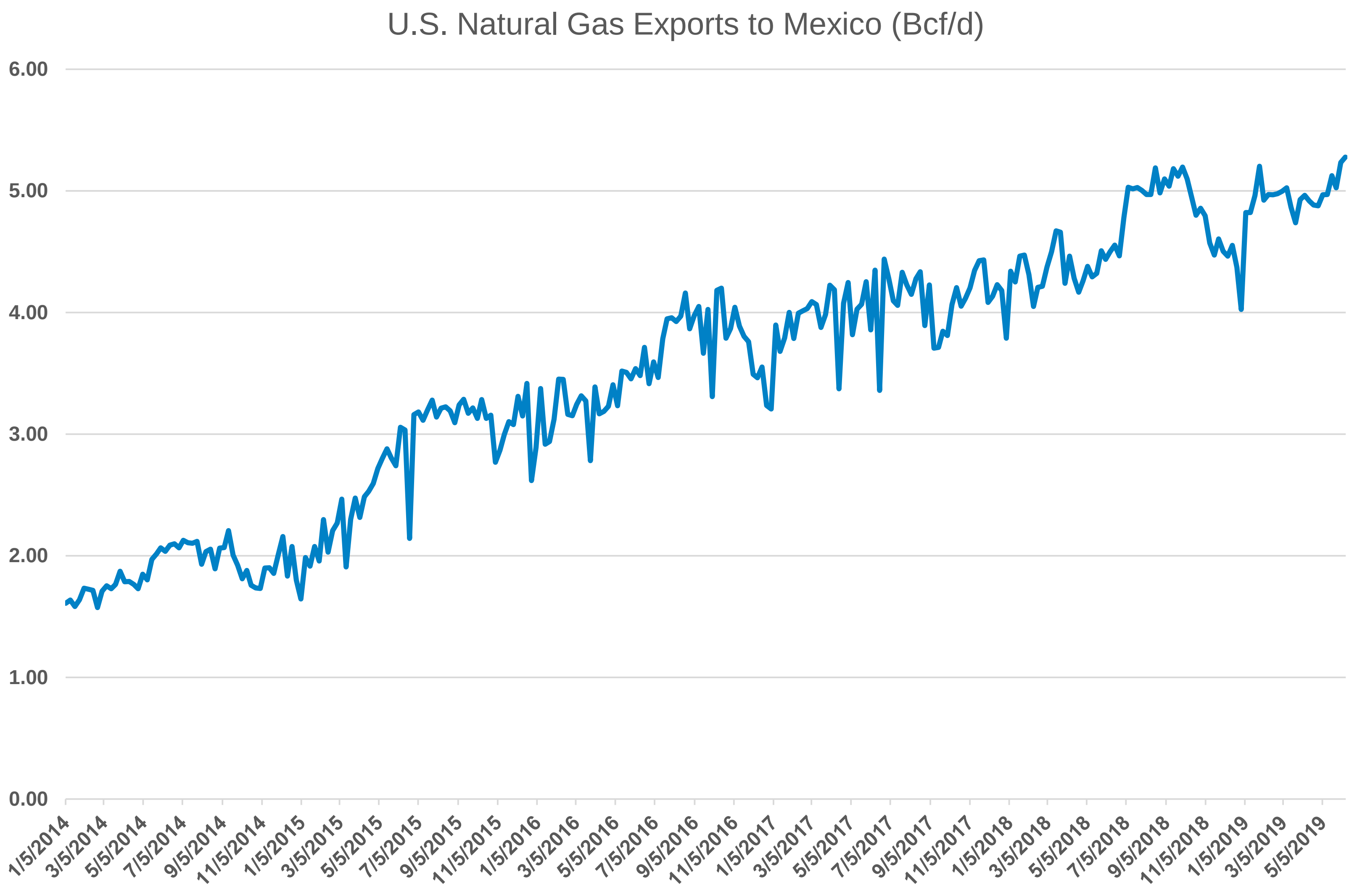
Source: Platts

LNG Growth Expected to Continue



Source: Operator Estimates

U.S. Natural Gas Exports to Mexico Making New Highs



Source: Bloomberg

NGL Macro Outlook

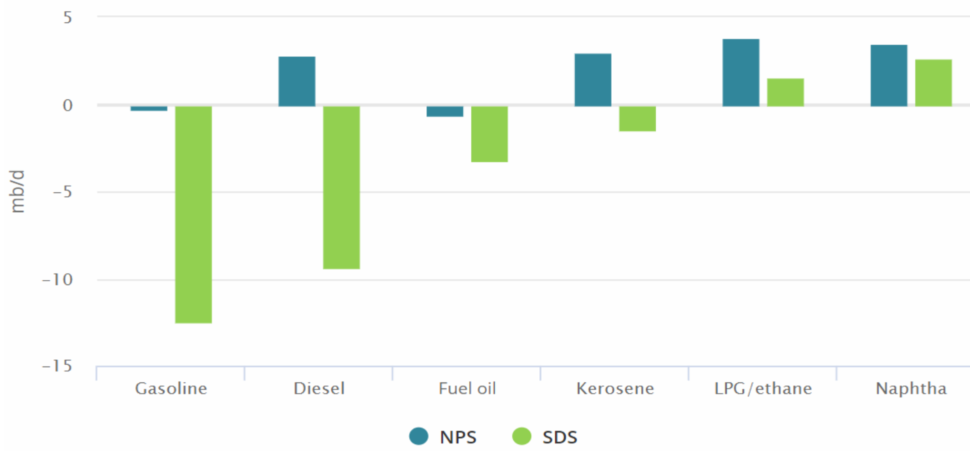
NGL Demand

- IEA forecasts LPG (propane and butane) and ethane to be the fastest growing global oil products over medium and long term
- Demand growth driven primarily by petrochemical feedstock demand and residential demand in developing countries
- U.S. waterborne export capacity increases in 2019 equivalent to ~15% of U.S. LPG supply, which should tighten balances going forward

Fractionation Tightness to Return in 2019

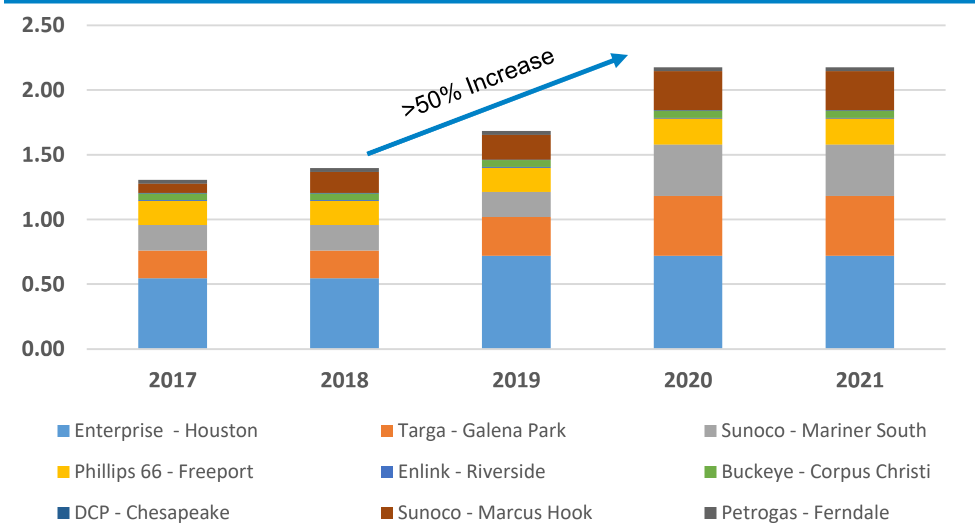
- NGL price rally in Summer 2018 was driven by U.S. fractionation capacity tightness that was temporarily relieved by:
  - Winter weather driving natural gas price spikes and lower C2 recovery
  - Midwest C3 being consumed locally rather than flowing to the Gulf Coast
- Range expects fractionation tightness to return in Summer 2019 as new ethane cracker startups (demand) outpace new fractionation additions (supply)

2017-2040 Change in Global Oil Product Demand by Scenario



Source: IEA World Energy Outlook 2018 (NPS = New Policy Scenario, SDS = Sustainable Development Scenario)

U.S. LPG Export Capacity (MMBL/D) Set to Increase



Source: Operator Estimates

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Financial Detail

Guidance

	2Q 2019	Full-Year 2019
Production (Mmcfe per day)	**2,270 to 2,280**	**2,325 to 2,345**
Capital Expenditures		**$756 million**
Operating Expense Guidance		
Direct Operating Expense per mcfe	$0.16 - $0.18	
TGP&C Expense per mcfe	$1.47 - $1.51	
Production Tax Expense per mcfe	$0.05 - $0.06	
Exploration Expense	$7 - $9 million	
Unproved Impairment Expense	$15 - $18 million	
G&A Expense per mcfe	$0.18 - $0.20	
Interest Expense per mcfe	$0.23 - $0.25	
DD&A Expense per mcfe	$0.68 - $0.74	
Net Brokered Marketing Expense	$3 million	
Pricing Guidance		
Natural Gas Differential to NYMEX	($0.24)	($0.15) - ($0.20)
NGLs (pre-hedge & including ethane)		34% - 38% of WTI
Oil/Condensate Differential to WTI		($6.00) - ($8.00)

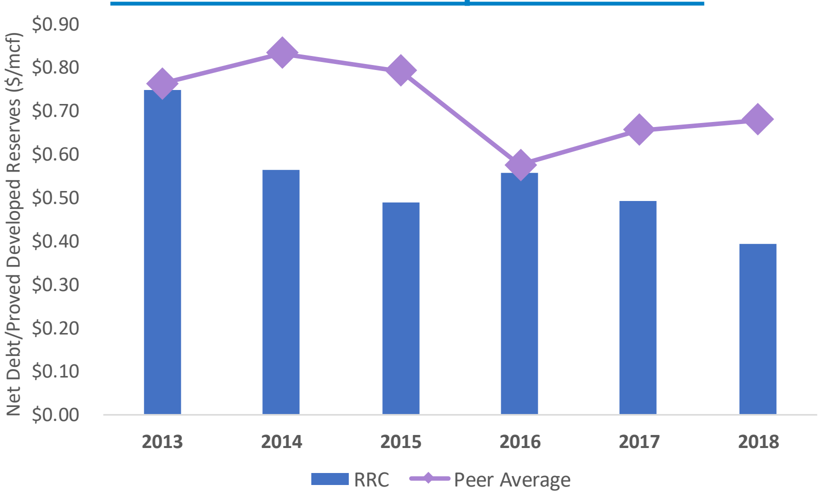
Well-Structured, Resilient Balance Sheet

- $4 billion credit facility,
  ($3B borrowing base, $2B committed)
- No note maturities until 2021
- Simple capital structure
- Near-term cash flow protected with hedges

Capital Structure[a]

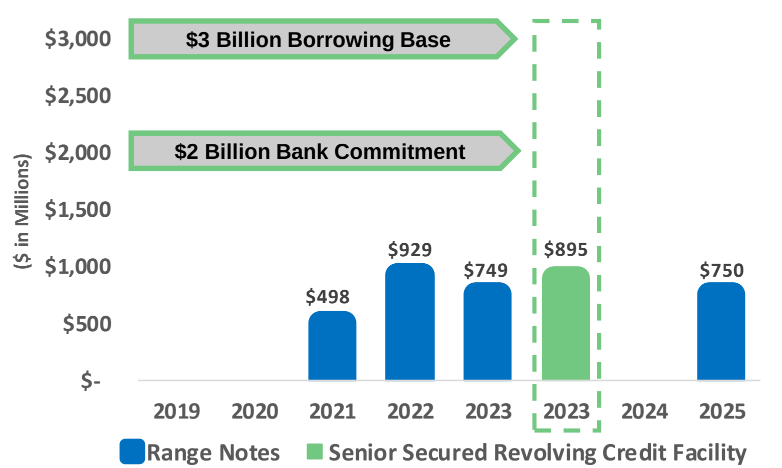
(millions)	1Q19
Bank Debt	$ 895
Senior Notes	2,877
Senior Sub Notes	49
Debt	3,821
Debt to Capitalization	48%
Debt/TTM EBITDAX	3.2x

Debt/Proved Developed Reserves



Note: Peer average includes AR, CHK, CNX, COG, EQT, GPOR and SWN.

Debt Maturity Schedule[a]



Interest Rate	2021	2022	2023	2025
	5.75%	5.3%[b]	5.0%	4.875%

(a) As of 3/31/19 (b) Weighted-average interest rate of 2022 notes

Development Cost & Recycle Ratio Calculation

Cash margin per mcfe / PUD development costs per mcfe.

Numerator:

1Q19 Pre-Hedge Realized Price	$	3.37	per mcfe
1Q19 All-In Cash Costs	$	2.13	per mcfe
Adjusted Margin per Mcfe	$	1.23	per mcfe

Denominator:

Future Development Costs of YE 2018 PUDs	$	3.3	billion
Proven Undeveloped (PUD) Reserves at YE 2018		8.3	Tcfe
Future Development Costs per Mcfe	$	0.40	per mcfe

Unhedged Recycle Ratio	**3.1x**

Natural Gas & Oil Hedging Status

	Time Period	Volumes Hedged (Mmbtu/day)	Average Hedge Prices ($/Mmbtu)
Natural Gas[1] (Henry Hub)	2Q19 Swaps	1,350,000	$2.80
	3Q19 Swaps	1,425,109	$2.80
	4Q19 Swaps	1,428,261	$2.82
	FY20 Swaps	334,973	$2.77

	Time Period	Volumes Hedged (bbl/day)	Average Hedge Prices ($/bbl)
Oil (WTI)	2Q19 Collars	1,000	$63 x 73
	2H19 Collars	1,000	$63 x 73
	2Q19 Swaps	7,500	$55.25
	3Q19 Swaps	7,250	$55.50
	4Q19 Swaps	7,666	$55.64
	FY20 Swaps	1,624	$60.95

**As of 3/31/19*

1) *Range also sold call swaptions of 20,000 Mmbtu/d for winter 2019/2020 and 290,000 Mmbtu/d for calendar 2020 at average strike prices of $3.20 and $2.80 per Mmbtu, respectively.*

Liquids Hedging Status

	Time Period	Volumes Hedged (bbls/day)	Average Hedge Prices ($/gal)
Ethane (C2)	2Q19 Swaps	500	$0.35
Propane (C3)	2Q19 Collars 2Q19 Swaps	1,000 8,500	$0.90 x $0.96 $0.878
Natural Gasoline (C5)	2Q19 Swaps 3Q19 Swaps 4Q19 Swaps	5,000 1,500 1,500	$1.341 $1.472 $1.475

*As of 3/31/19

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