WHITING

Corporate Presentation

August 1, 2018

WLL POWER

Forward-Looking Statements and Non-GAAP Measures

This presentation contains statements that Whiting Petroleum Corporation (“Whiting”) believes to be “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding the expected future reserves, production, future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels of Whiting, and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. These risks and uncertainties include, but are not limited to: declines in, or extended periods of low, oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness, ability to comply with debt covenants and periodic redeterminations of the borrowing base under our credit agreement; impacts to financial statements as a result of impairment write-downs; our ability to successfully complete asset dispositions and the risks related thereto; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; inaccuracies of our reserve estimates or our assumptions underlying them; risks relating to any unforeseen liabilities of ours; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations; federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions; unforeseen underperformance of or liabilities associated with acquired properties; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; availability of, and risks associated with, transport of oil and gas; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; the potential impact of changes in laws, including tax reform, that could have a negative effect on the oil and gas industry; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry; cyber security attacks or failures of our telecommunication systems; and other risks described under the caption “Risk Factors” in our Annual Report on Form 10-K for the period ended December 31, 2017. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this news release. Whiting’s 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.

In this presentation, we refer to Discretionary Cash Flow, which us a non-GAAP measure that Whiting believes are helpful in evaluating the performance of its business. A reconciliation of such non-GAAP measure to the relevant GAAP measures can be found at the end of the presentation.

Strategic Vision

Achieve Industry Leading Results in Capital Efficient Development of Resource Plays

- **Maximize economic returns at the drilling spacing unit and corporate level.**
- **Deliver multi-year growth and free cash flow at a $55 NYMEX oil price.**
- **Reduce Debt to EBITDAX ratio below 2:1 at a $55 NYMEX oil price.**
- **Maintain a strong hedge position (60-70% of oil volumes) 12-24 months forward.**
- **Maximize value from the sand face to the sales point.**

2018: Disciplined Growth and Free Cash Flow

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2018 Initiatives

- Implemented an optimized completion strategy to enhance capital efficiency at the drilling spacing unit level.
- Added a drilling rate of return metric to the executive compensation plan.
- Improved netbacks at the wellhead through a greater focus on the oil and gas marketing process and contract structure.
- Reorganized the Bakken team structure to streamline communications and learning across the organization.

2Q Results

- Q2 2018 average production of 126,180 BOE/d at the high end of guidance.
- Q2 2018 net cash from operations of $310 million exceeded capex by $107 million and discretionary cash flow of $269 million exceeded capex by $66 million.
- Q2 2018 LOE of $7.81 per BOE at low end of guidance.
- Successful infill pilot McNamara Project in Sanish.
- Completed bolt-on in McKenzie County of 54,833 net acres and 1,290 BOE/d for $130 million.

2018 Capital Budget: Spending Below Cash Flow

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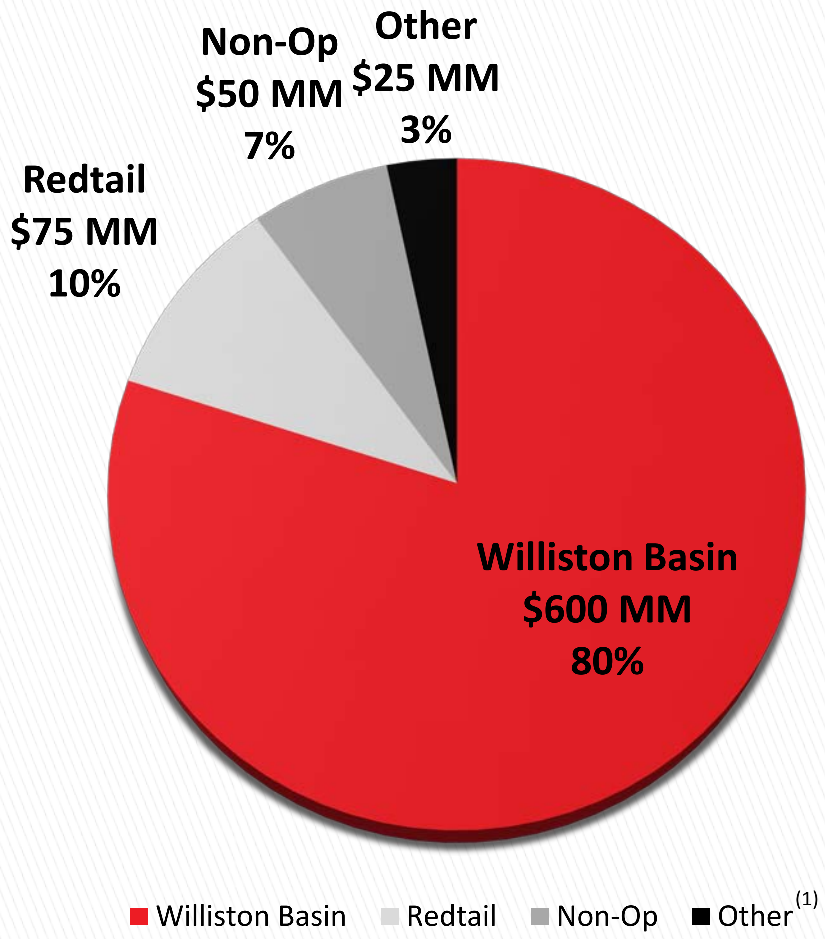
Capital Plan Highlights

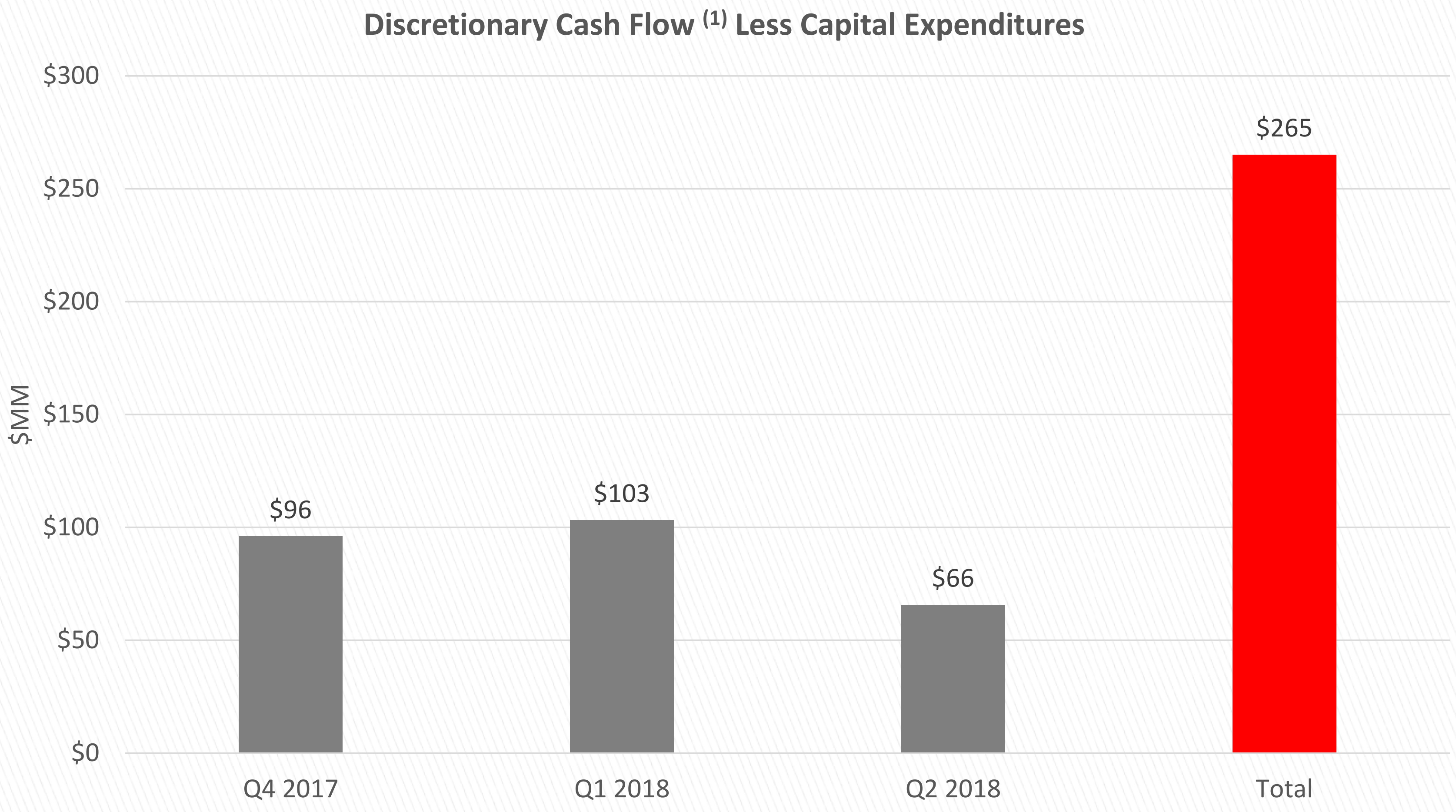
- Forecast Average 2018 Production of 128,400 BOE/d
  - 9% Growth over 2017 Average
- Williston Basin operated production forecast to grow 14% from Q4 2017 to Q4 2018
- Forecast to generate solid free cash flow at a $55+ NYMEX oil price
- 2018 Total Capex of $750 Million
- Plan to drill 120 Bakken/Three Forks wells in the Williston Basin
- Plan to Put On Production (POP) 145 Wells
  - 123 Williston Basin
  - 22 Redtail

Capital Budget of $750 Million



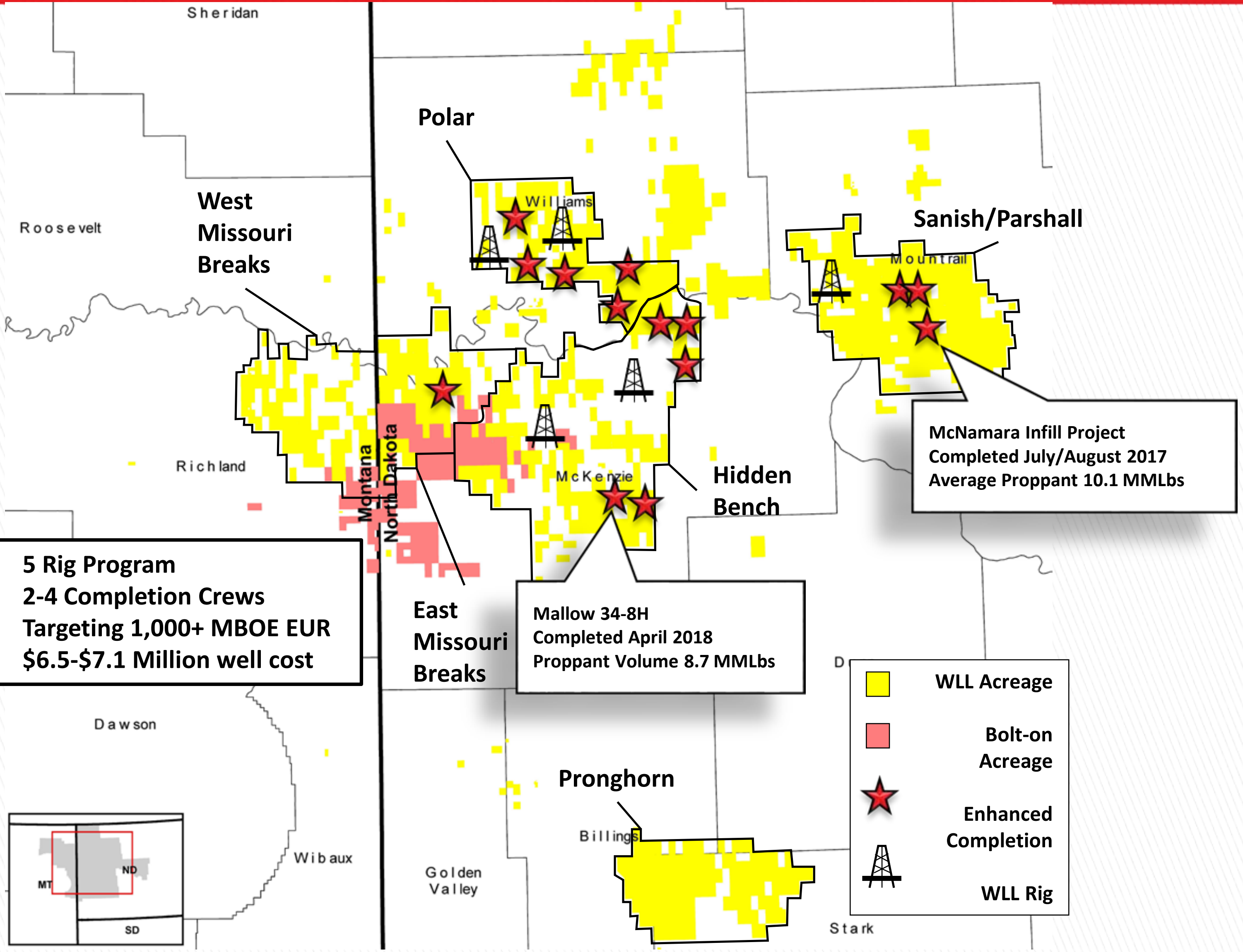
(1) Other consists of land and facilities.

Consistently Generating Cash Flow Above Capex



(1) For reconciliation of discretionary cash flow above capex to the applicable GAAP measure, see the reconciliation later in this presentation.

Top Acreage Position across the Core Williston Basin



- 5 Rig Program
- 2-4 Completion Crews
- Targeting 1,000+ MBOE EUR
- $6.5-$7.1 Million well cost

Tier 1 Areas

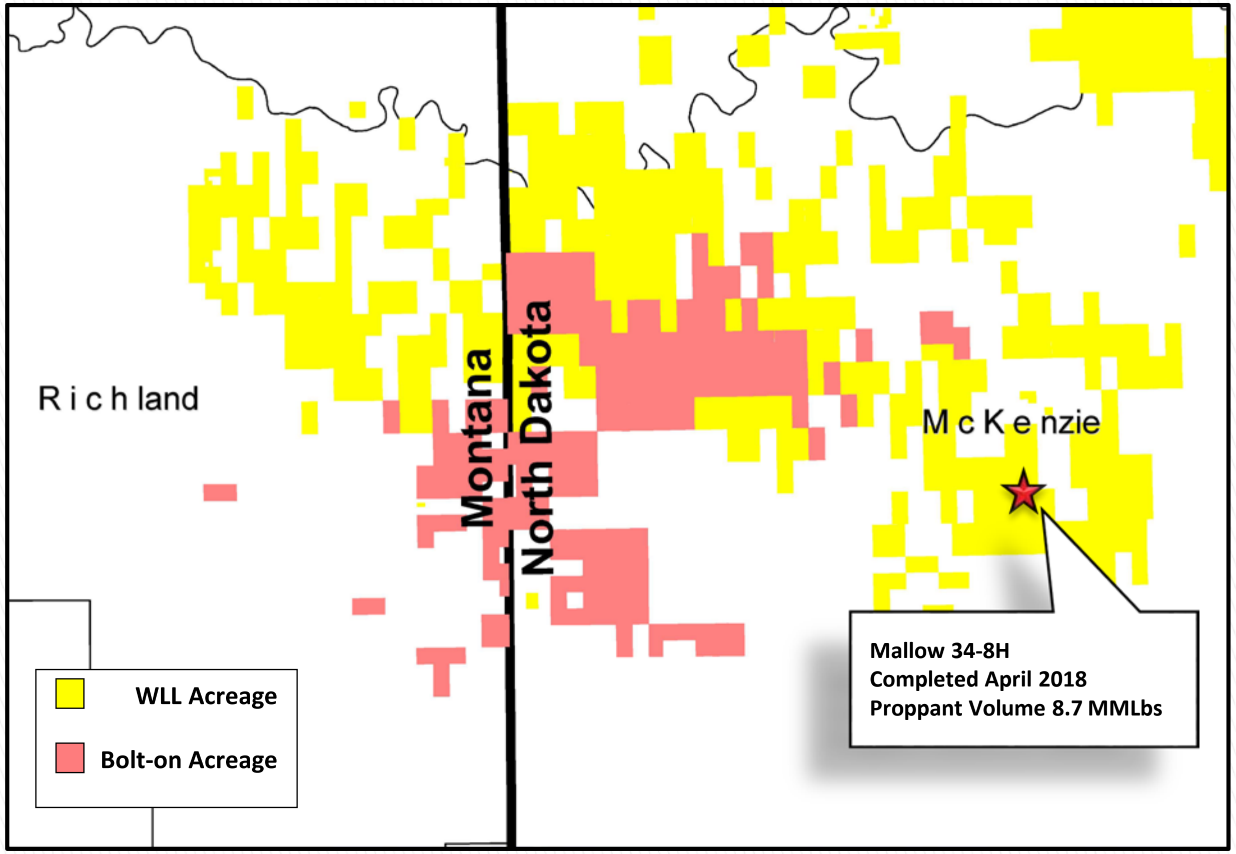
Area	Gross Acres	Net Acres	Total Potential Net Wells
East Missouri Breaks	61,527	29,882	90
Hidden Bench	103,486	75,381	440
Polar	98,311	51,271	256
Sanish / Parshall	171,413	82,099	336
Total Tier 1	**434,737**	**238,633**	**1,122**

Tier 2 Areas

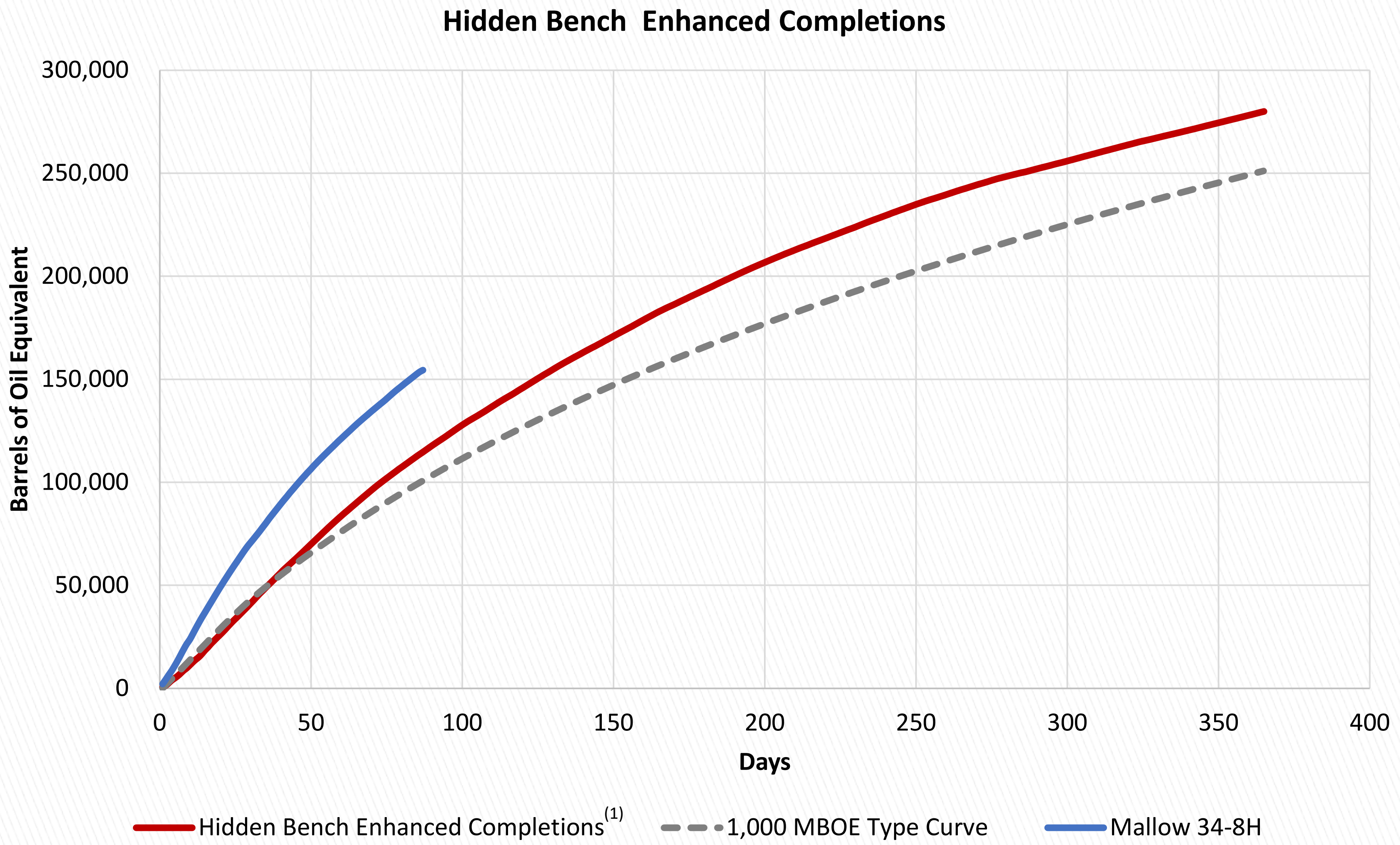
Area	Gross Acres	Net Acres	Total Potential Net Wells
Pronghorn	114,633	81,029	176
West Missouri Breaks	65,722	51,769	152
Other	64,848	35,671	230
Total Tier 2	**245,203**	**168,469**	**558**
Grand Total	**679,940**	**407,102**	**1,680**

Bakken Bolt-On Contiguous with Core Areas

- $130 million purchase price funded from free cash flow.
- 54,833 net acres overlap in Hidden Bench and East Missouri Breaks acreage.
- 1,290 BOE/d of production.
- 26 MMBOE of estimated proved reserves.
- Closed July 31, 2018



Mallow Highlights Southern Hidden Bench Quality



(1) Data set includes 27 wells completed since January 2015.

Polar Generation 4.0 Completions Outperforming Legacy 10 Million lb. Offset

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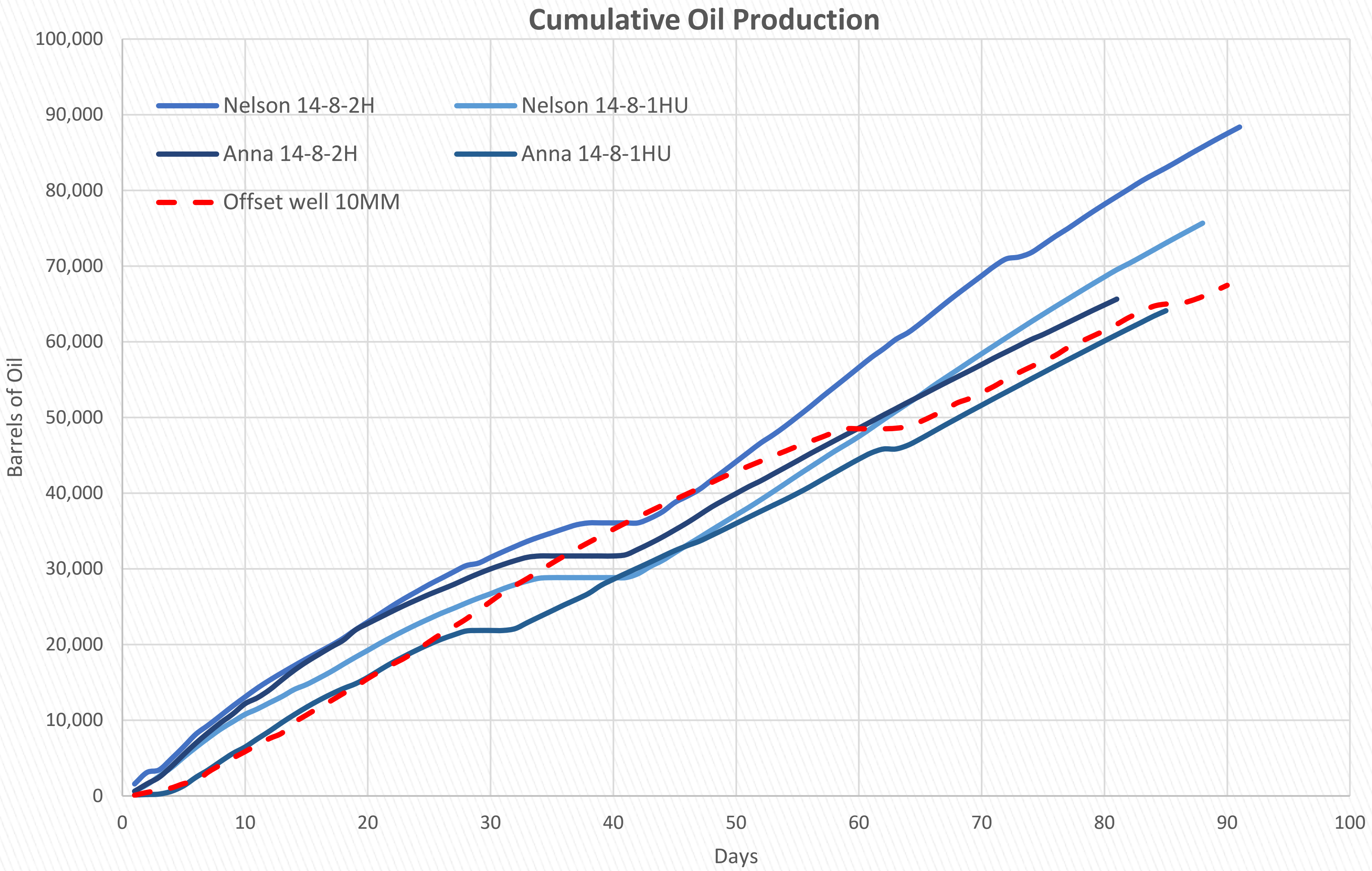
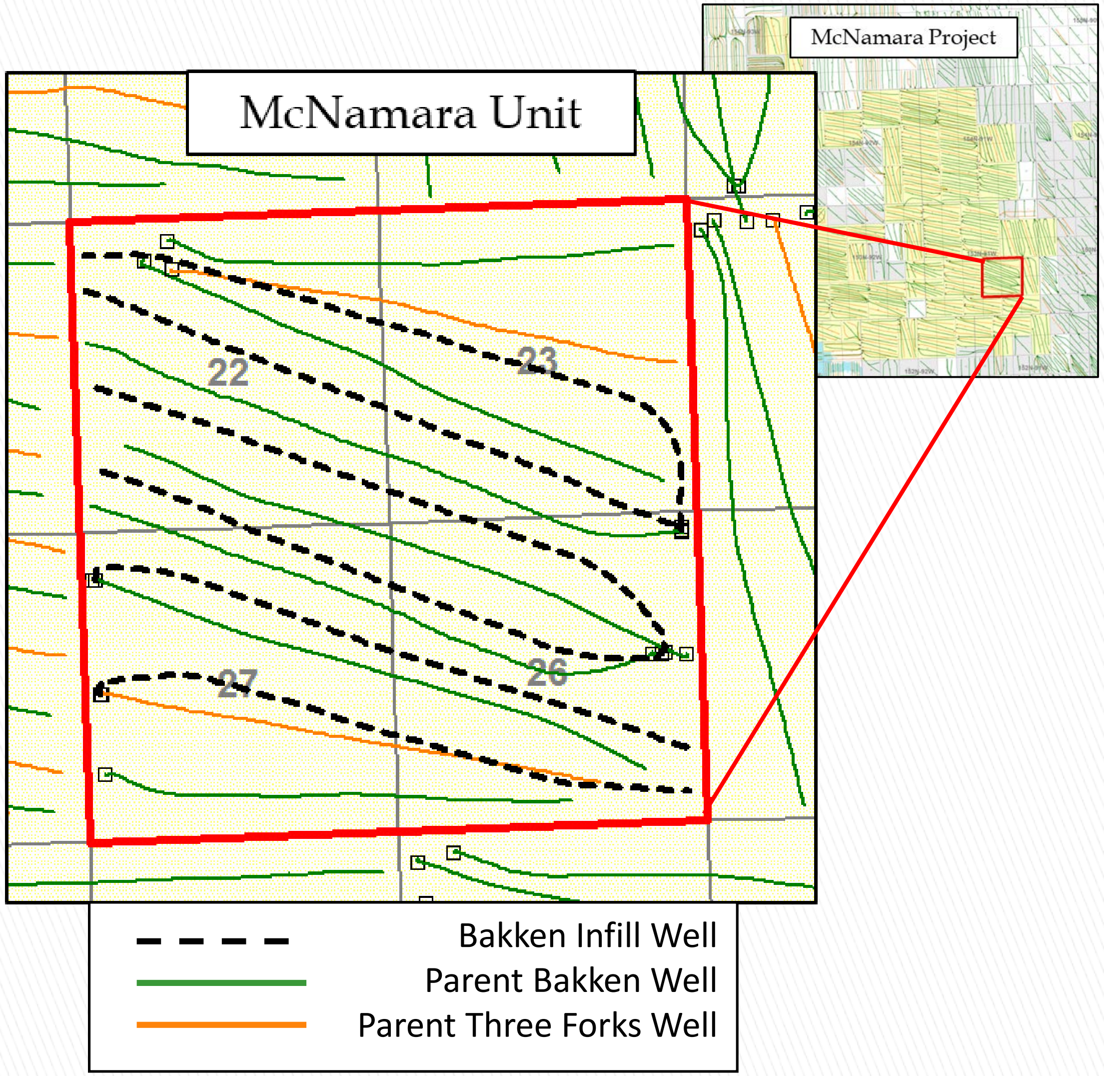
- **North Polar, Anna/Nelson wells completed w/ 6.5MM to 7.5MM lbs & Gen 4.0 diversion techniques.**
- **Nearby offset well (red dashes) completed w/ 10 MM lb job and less sophisticated diversion method.**
- **New diversion technique allowing WLL to complete better performing wells with a 30% reduction in proppant, reducing capex by approximately $400,000 per well.**
- **This efficient completion strategy also allows WLL to better contain frac in zone. This has reduced the water cut by 10% vs the 10MM well. This is estimated to lower our overall LOE by $600,000 over the life of a new Gen 4.0**
- **SUMMARY: Diversion and "Right Sizing" completions reduces capex and LOE while delivering strong well performance.**



McNamara Infill Project Highlights Sanish Quality



Project Goals

- Drill 6 Bakken infill wells and complete utilizing Whiting optimized completions.
- Maximize recovery factor in a high OOIP area.
- Protect parent well production.

Parent Well Stats

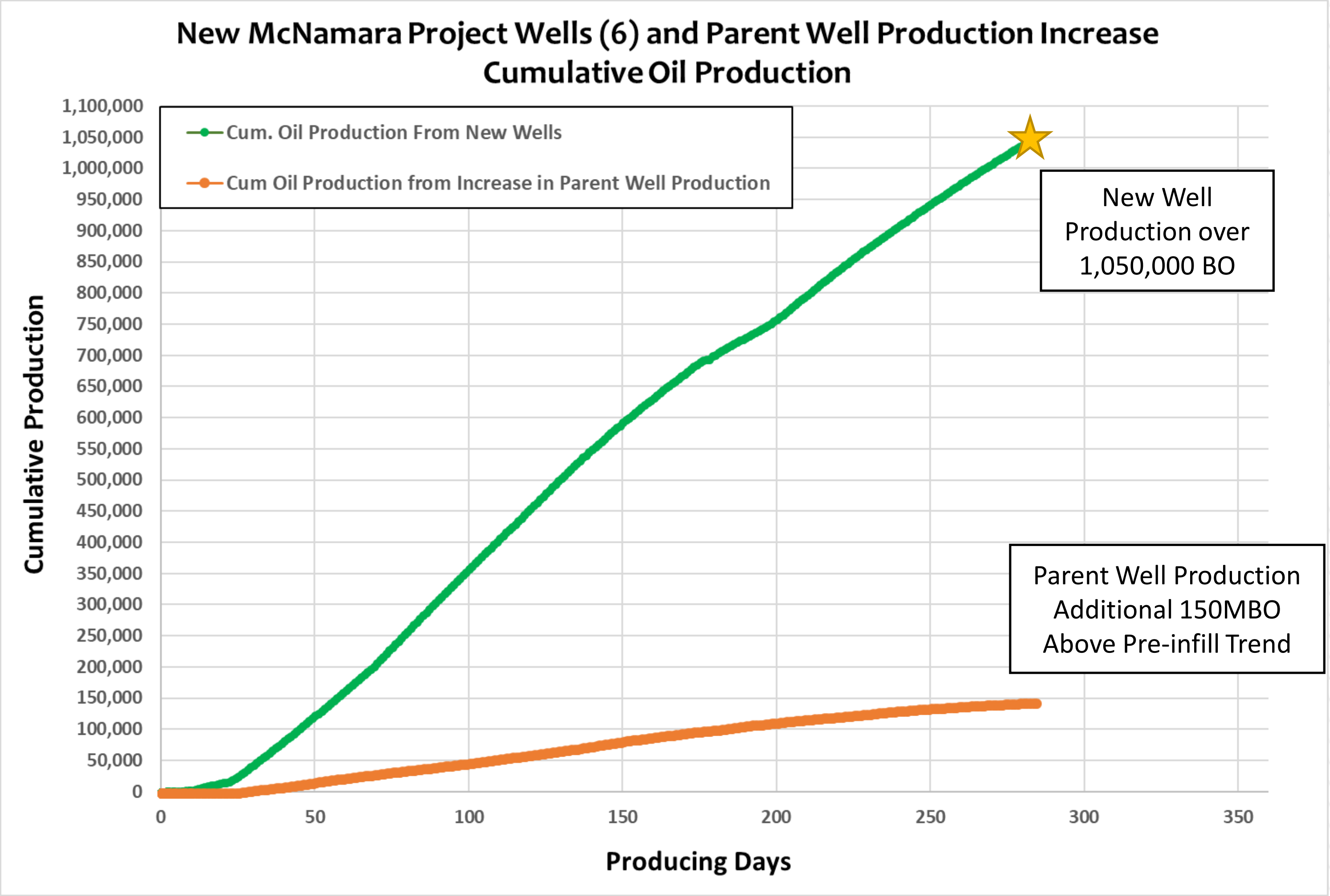
- 9 Parent wells completed in 2007 & 2012.
- 7 Bakken & 2 Three Forks Wells.

Result

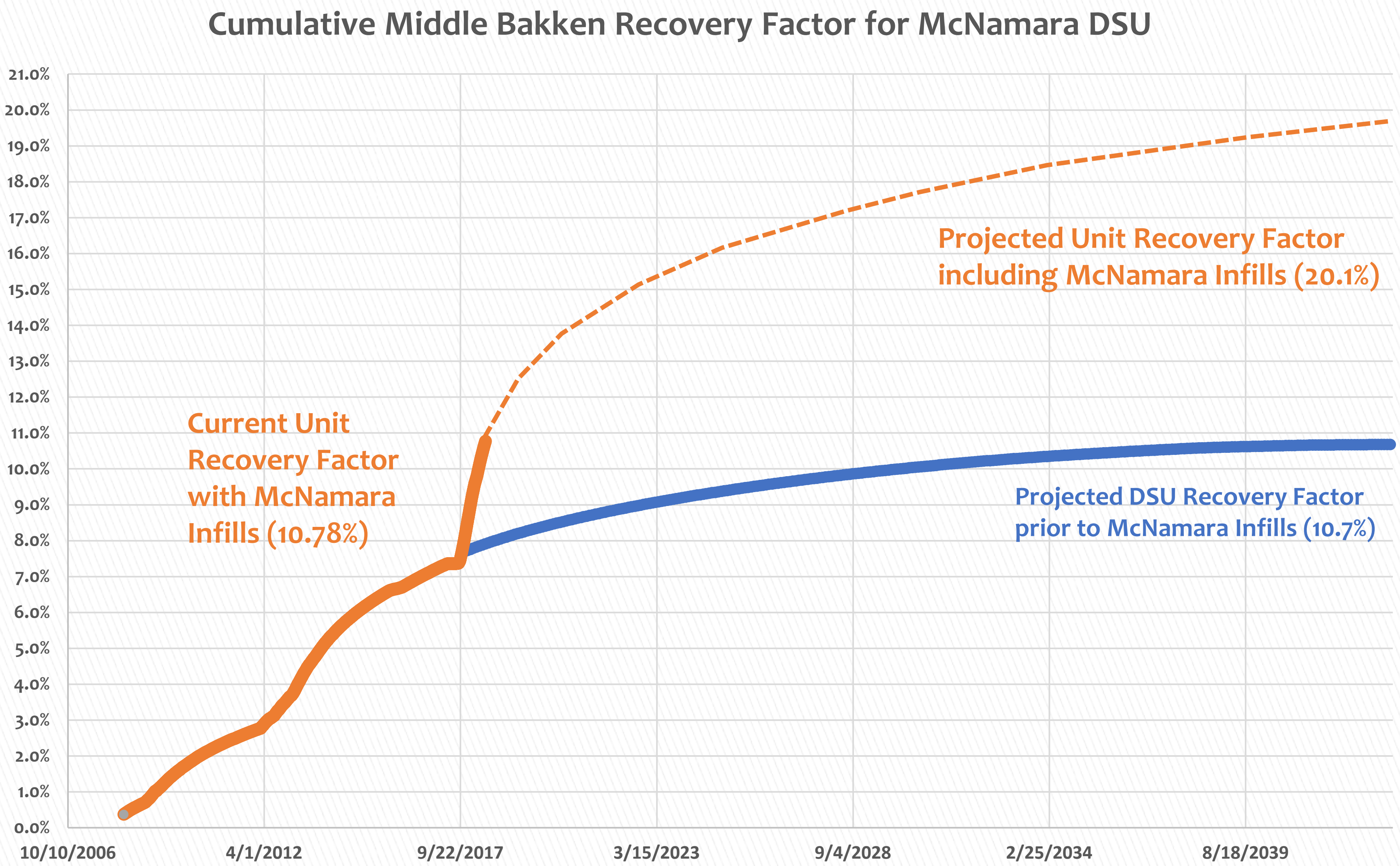
- At $60 NYMEX oil price McNamara project generates an estimated IRR of 53%.
- With learnings from the first infill project in the field we could reduce frac protect costs and capex. 53% could move to 70%+ IRR.
- 1.5 year payout.

Total McNamara DSU Recovery Enhanced

Project Has Produced More Than 1.2 MMBO Since September 2017



McNamara Unit Projected Recovery Factor



A Leader in Optimizing Completions

Previous Designs

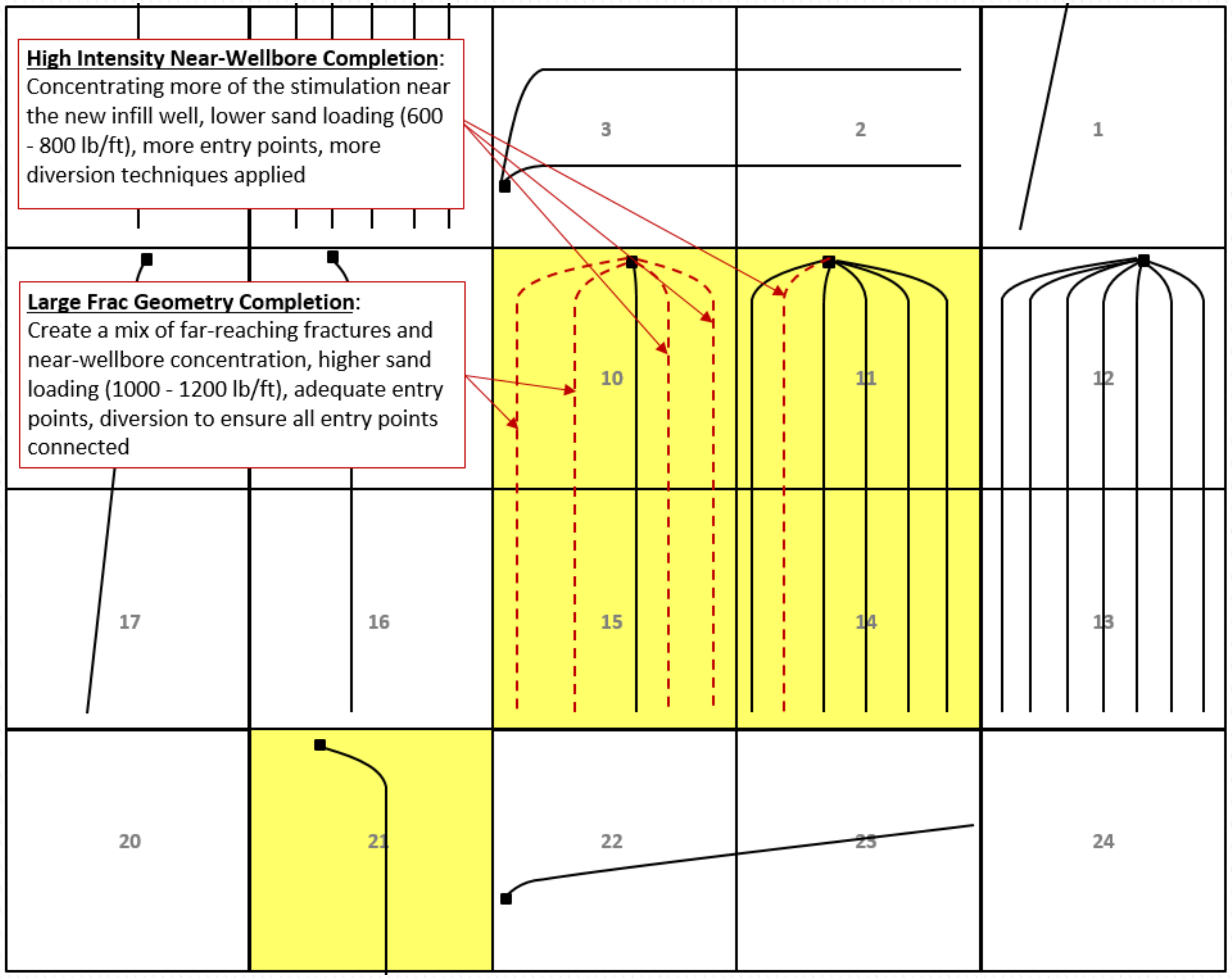
Generation 1: 2010-2012
- 240 lbs/ft proppant
- 380' stage spacing
- 4 bbl/ft fluid
- 380' cluster spacing
- Packer, Ball-and-Sleeve

Generation 2: 2013-2015
- 390 lbs/ft proppant
- 300' stage spacing
- 9 bbl/ft fluid
- 150' cluster spacing
- Mix of Packer, Ball-and-Sleeve & Cemented liner PnP

Generation 3: 2016-2017
- 930 lbs/ft proppant
- 240' stage spacing
- 25 bbl/ft fluid
- 42' cluster spacing
- All cemented liner PnP
- Diversion technology in use

Optimized Design

Generation 4 (Right-Sized Completions): 2018
- 600 – 1,200 lbs/ft proppant
- 200' – 300' stage spacing
- 15 - 40 bbl/ft fluid
- 30' – 50' cluster spacing
- All cemented liner PnP
- Diversion technology in use, evolving
- Optimize the completion to the situation
- Large geometry completions for Infill wells in DSUs with high remaining recoverable oil in place
- Near-wellbore completions for DSUs with high parent well count



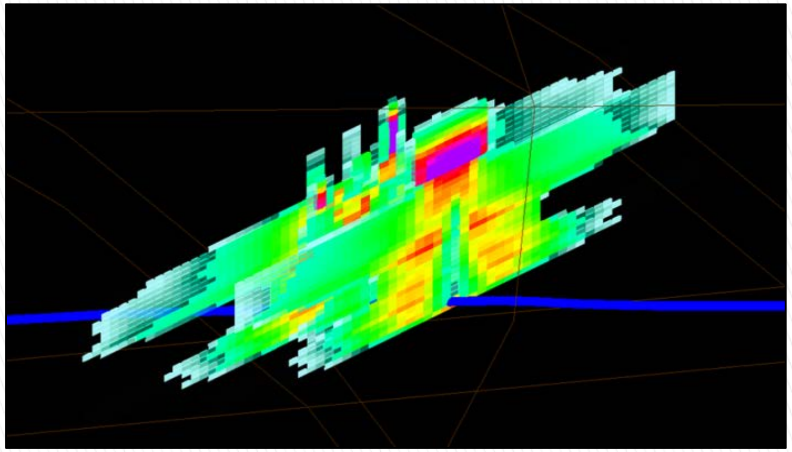
The Optimum Frac Design for each specific area

Differences in reservoir and mechanical properties exist across the Williston Basin.

- Every area requires a customized completion design.

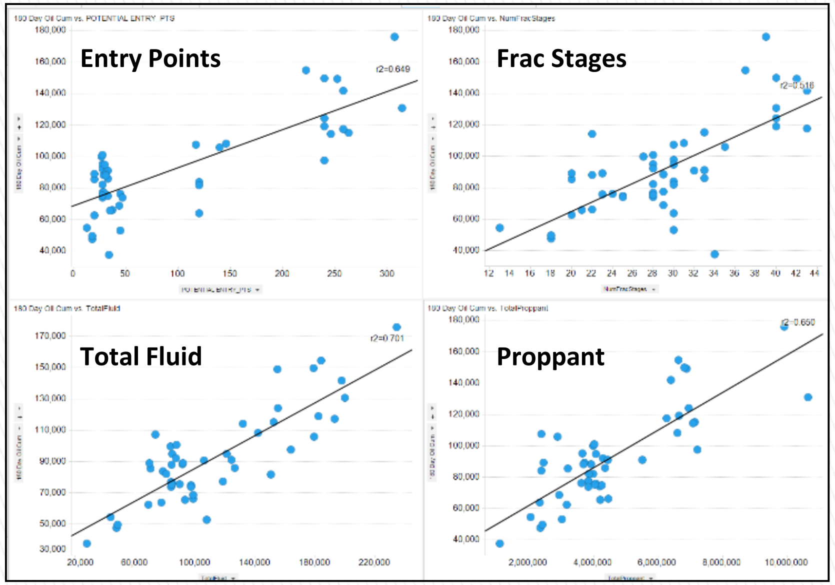
Strategy for the optimum design:

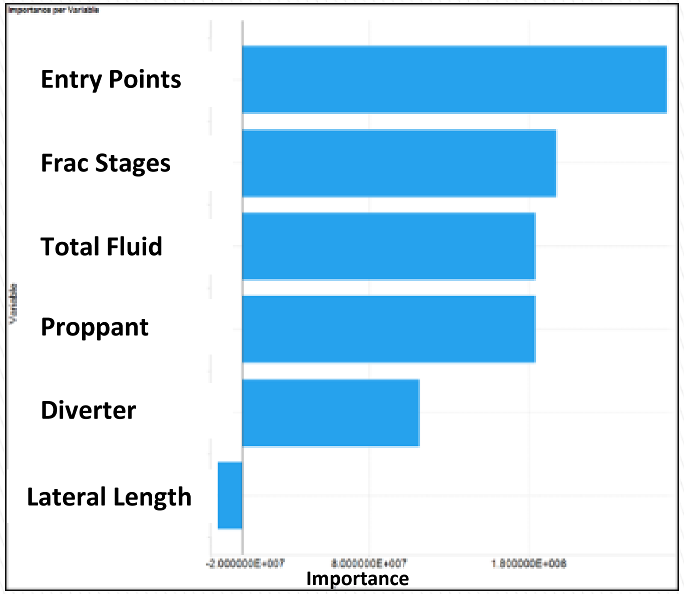
- Build calibrated completion models for every prospect area.
- Use multivariate analysis to understand which completion factors most heavily affect the results in each area.
- Pilot and adopt the latest completion technologies available through preferred service companies.



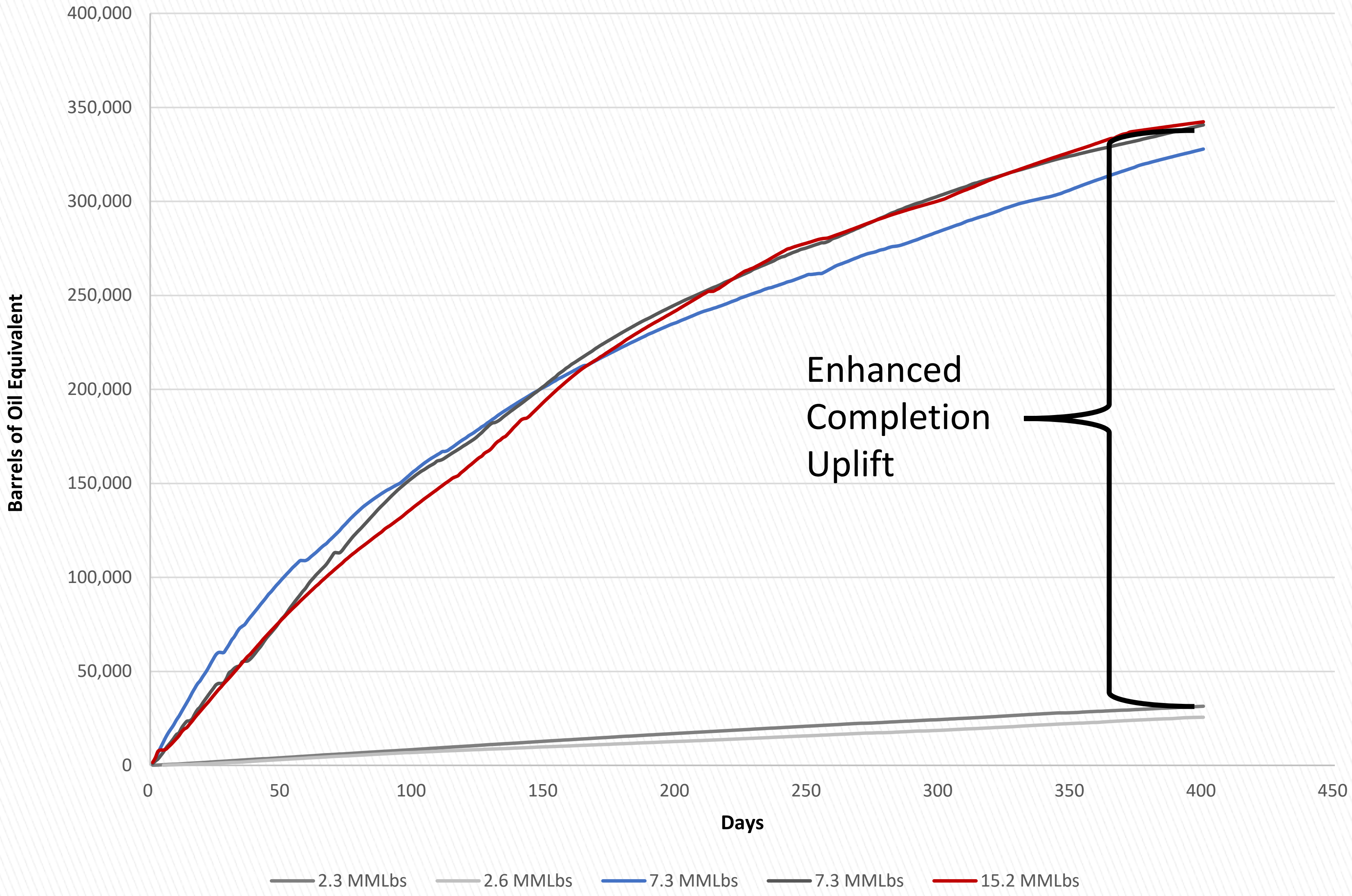
Example frac geometry from GOHFER® frac model

Example of Multivariate Analysis for a Specific Region





Finding the Optimum Size at Hidden Bench

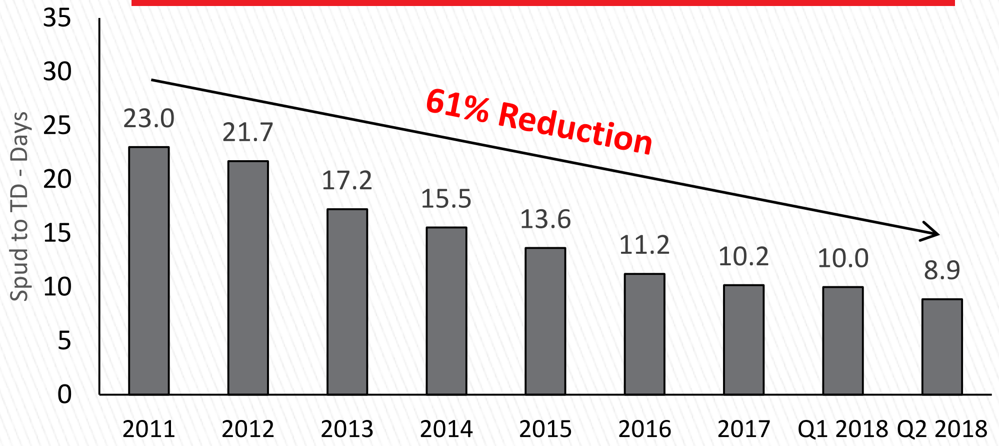


Optimizing a DSU

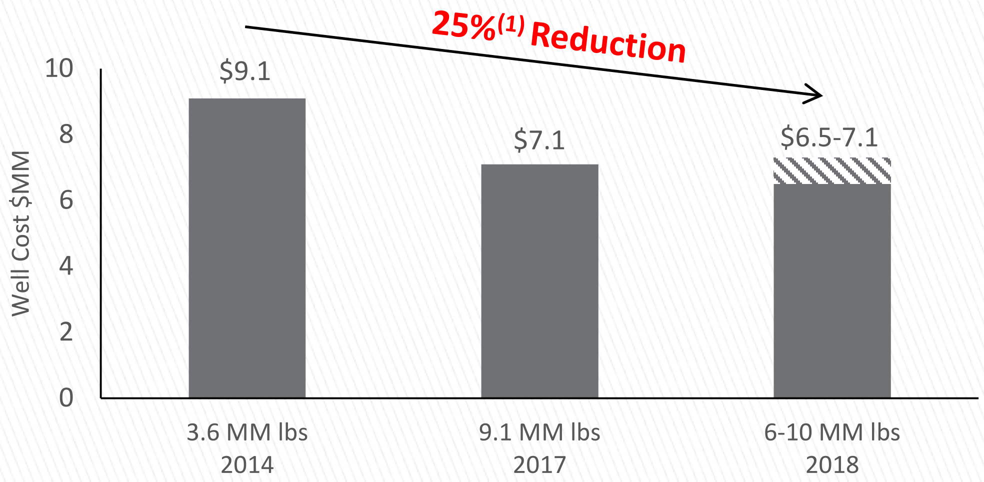
- 5 Bakken wells (Hidden Bench Area)
- Single DSU
- Wells stimulated with less than 3 MMlbs were underperformers
- Strong production increase going to 7.5 MMlbs
- No apparent production increase seen at 15 MMlbs

Continuous Improvement in Operations

Continually Improving Drilling Efficiency



Industry Leading Completion Technology



(1) Based on the estimated 2018 mid-point well cost.

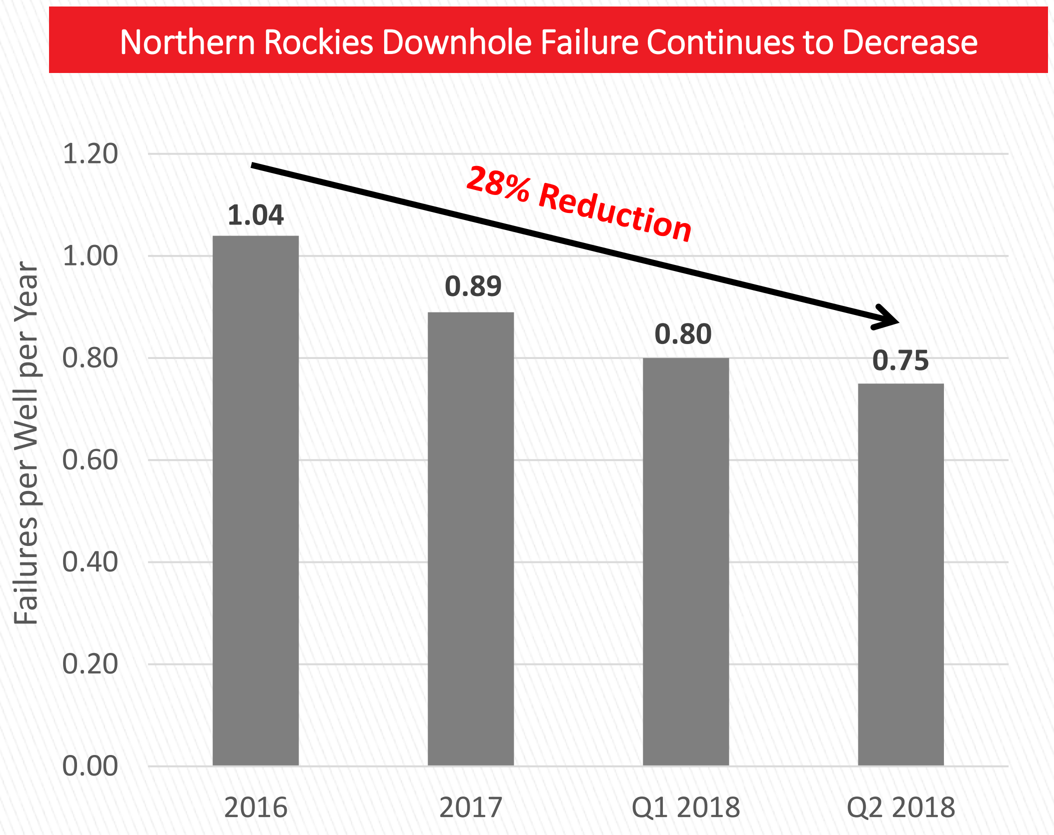
Drilling

- Industry leader in drilling performance with 61% reduction in SPUD to TD since 2011.
- Utilizing state of the art drilling rigs, high-torque mud motors and 3D bit cutter technology to reduce time on location and well costs.
- Leveraging Whiting's vast experience of drilling 6,500 miles of wellbore in the Williston Basin since 2006.

Completion

- Industry leader in advancement of completion technology, completion efficiency and cost efficiency.
- Leverage increased efficiency, logistics and market to increase stimulation by 3x while reducing well costs 25%.
- Continuing to advance leading position in 2018 by implementing technologies to increase pumping efficiency and fracture intensity near wellbore to increase well performance and reduce cost.

Optimization Efforts Lead to Decreased Downtime

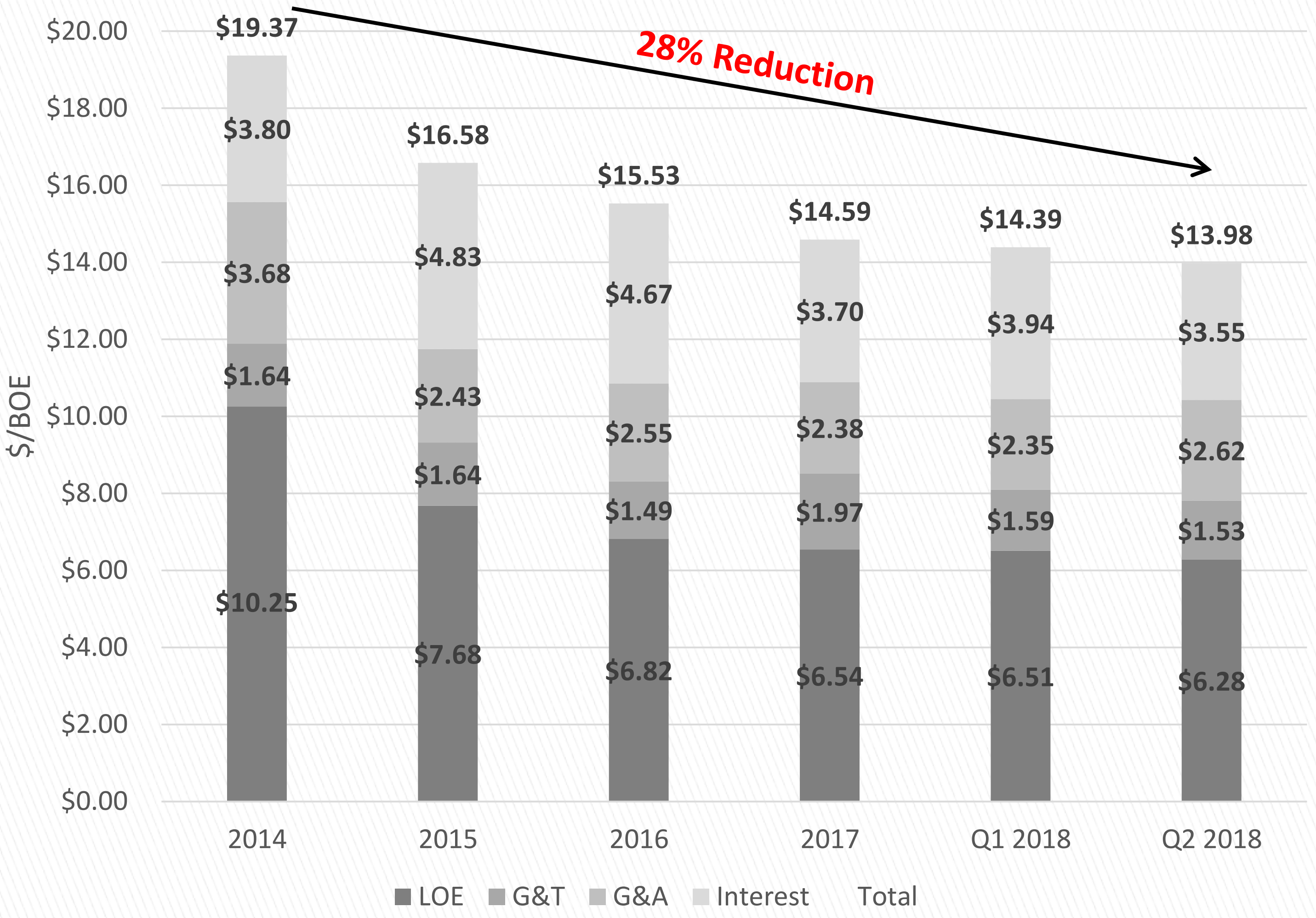


Optimizing Production and Reducing LOE

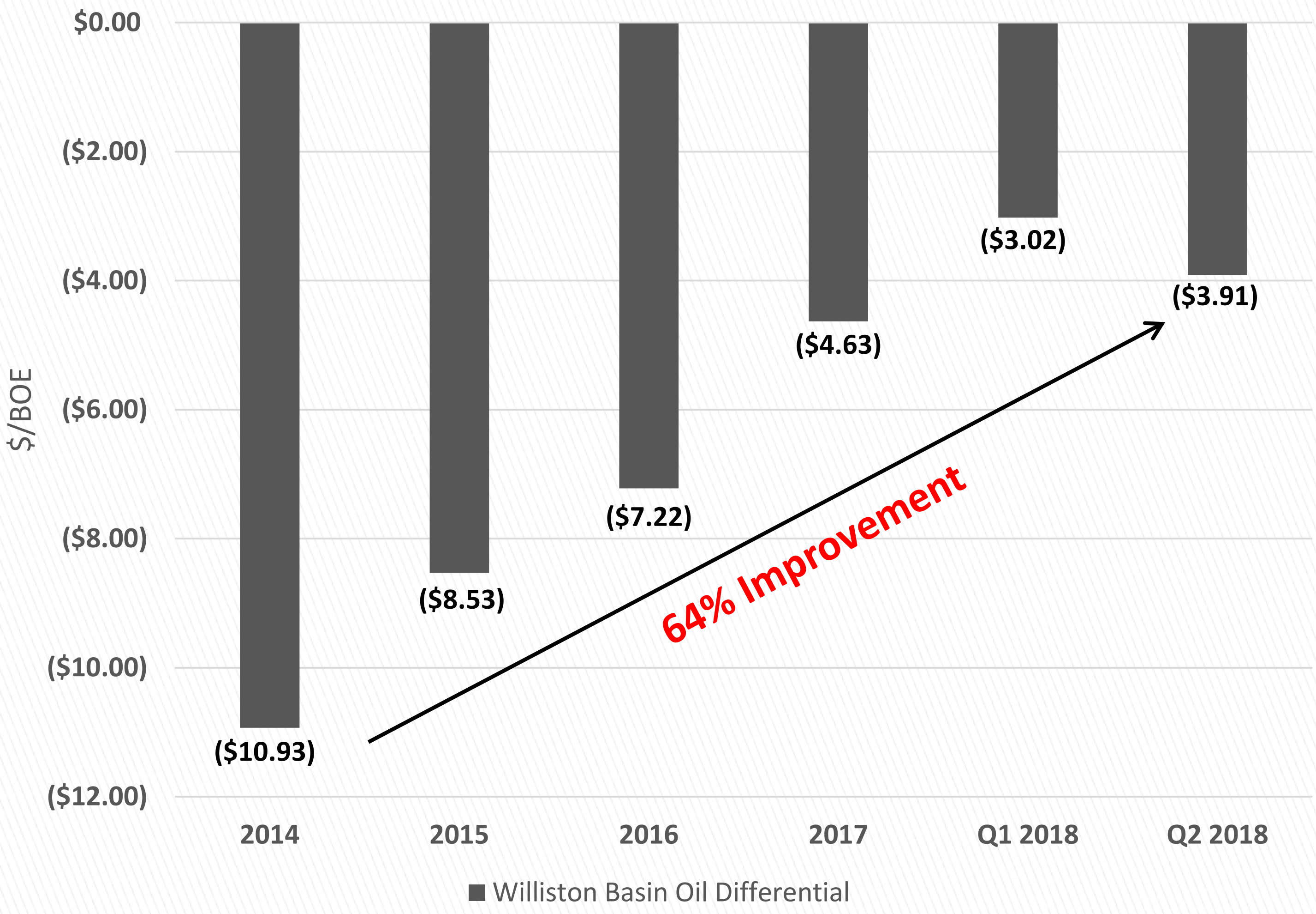
- Implemented advanced well monitoring and intervention techniques utilizing SCADA.
  - Reduced downhole failure rate by 28% over two year period.
  - Employed predictive analytic software to improve downhole design.
  - Utilizing advanced downhole tubular and rod metallurgies.
  - Optimized pumping unit driver parameters and improved chemical programs.

Driving Cash Costs Down

- Established pipe gathering systems for produced water.
- Renegotiated lower rates for existing produced water systems.
- Currently 85% of produced water is piped.
- Implemented advanced well monitoring and intervention technologies.

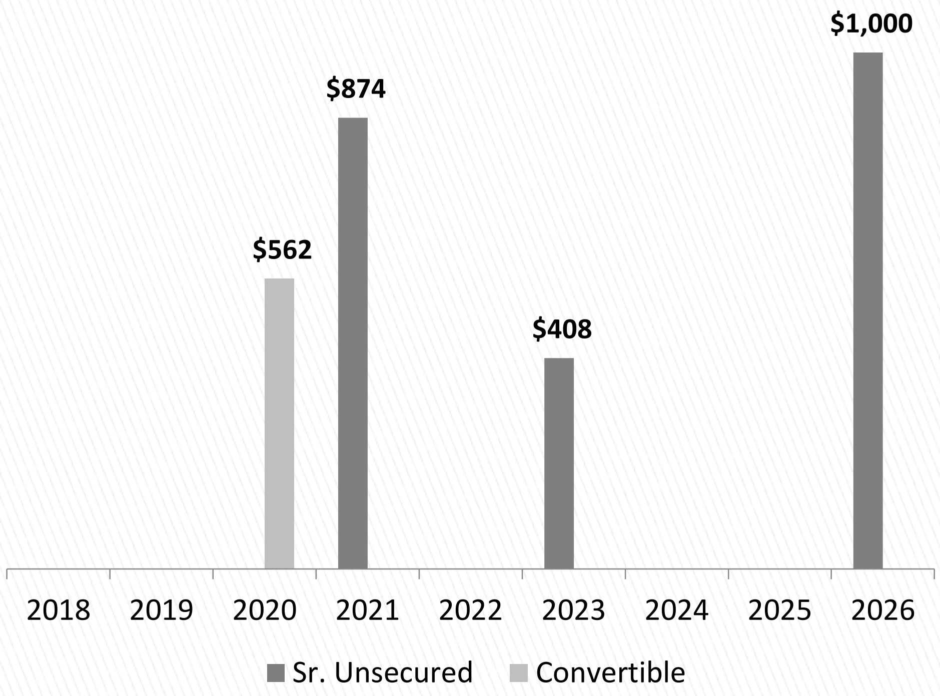


Strong Williston Basin Differentials Enhance Cash Flow



Strong Balance Sheet Liquidity and Financial Flexibility

Well Staged Bond Maturity Profile as of 6/30/2018 ($ Millions)

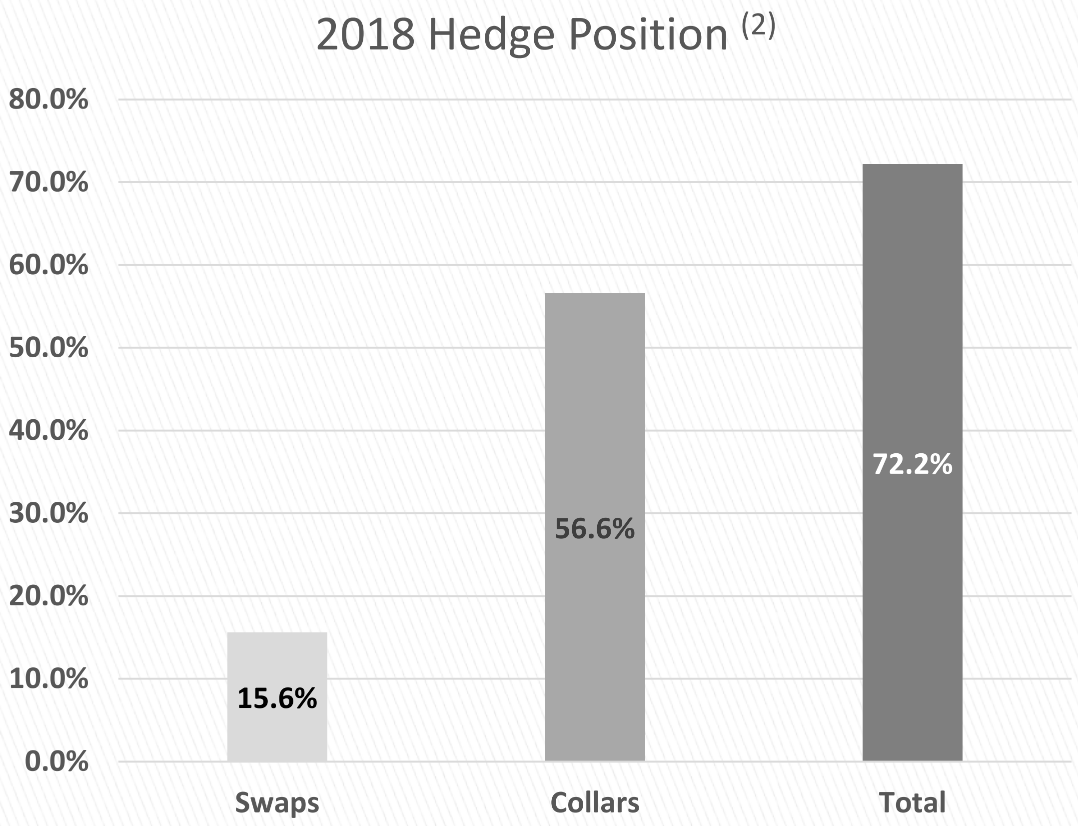


- $1.75 billion of bank credit commitments on a $2.4 billion borrowing base.
  - No borrowings outstanding as of 6/30/2018.
  - Bank credit agreement through 4/12/2023.

- Bank credit agreement covenants:
  - Total Debt to EBITDAX less than 4.0:1. It was 2.5:1 as of 6/30/2018.
  - Current Ratio greater than 1:1. It was 4.0:1 as of 6/30/2018.

- No bond maturities until 2020.
  - Bond Finance Covenant: Ratio of consolidated cash flows to fixed charges (interest expense) must be greater than 2.0:1. It was 5.5:1 as of 6/30/2018.

Strong Hedge Position (1)



Derivative Instrument	Hedge Period	Contracted Crude (Bbls per Month)	Weighted Average NYMEX Price (per Bbl)	As a Percentage of June 2018 Oil Production
Three-way collars (3)	**2018**		**Sub-Floor/Floor/Ceiling**	
	Q3	1,450,000	$37.07 - $47.07 - $57.30	56.6%
	Q4	1,450,000	$37.07 - $47.07 - $57.30	56.6%
Swaps	**2018**		**Fixed Price**	
	Q3	400,000	$61.74	15.6%
	Q4	400,000	$61.74	15.6%
Collars	**2019**		**Floor/Ceiling**	
	Q1	600,000	$50.00 - $71.80	23.4%
	Q2	600,000	$50.00 - $71.80	23.4%

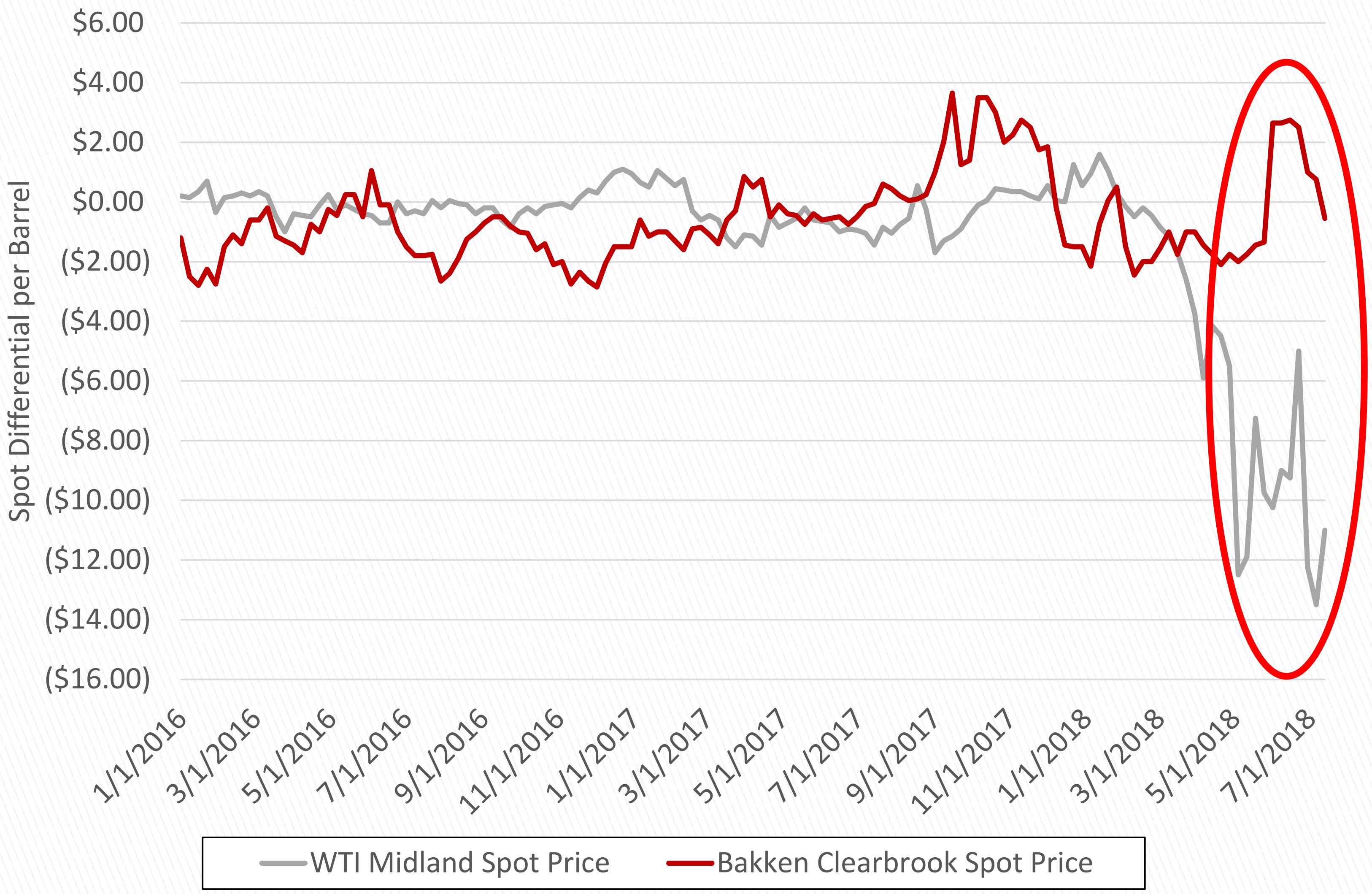
(1) As of July 1, 2018.
(2) As a percentage of June 2018 oil production.
(3) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Turning Rock Into Cash Flow

- Projecting growth and free cash flow in 2018.
- Managing the asset portfolio to maximize capital efficiency and corporate level returns.
- Strong debt maturity profile.
- Strong hedge position.
- A technology leader in the E&P sector.
- Top tier people in unconventional resource development.

Appendix

Recent Williston Basin Differentials Attractive



Source: Bloomberg spot oil prices.

Slower Activity Build Means Less Cost Pressure

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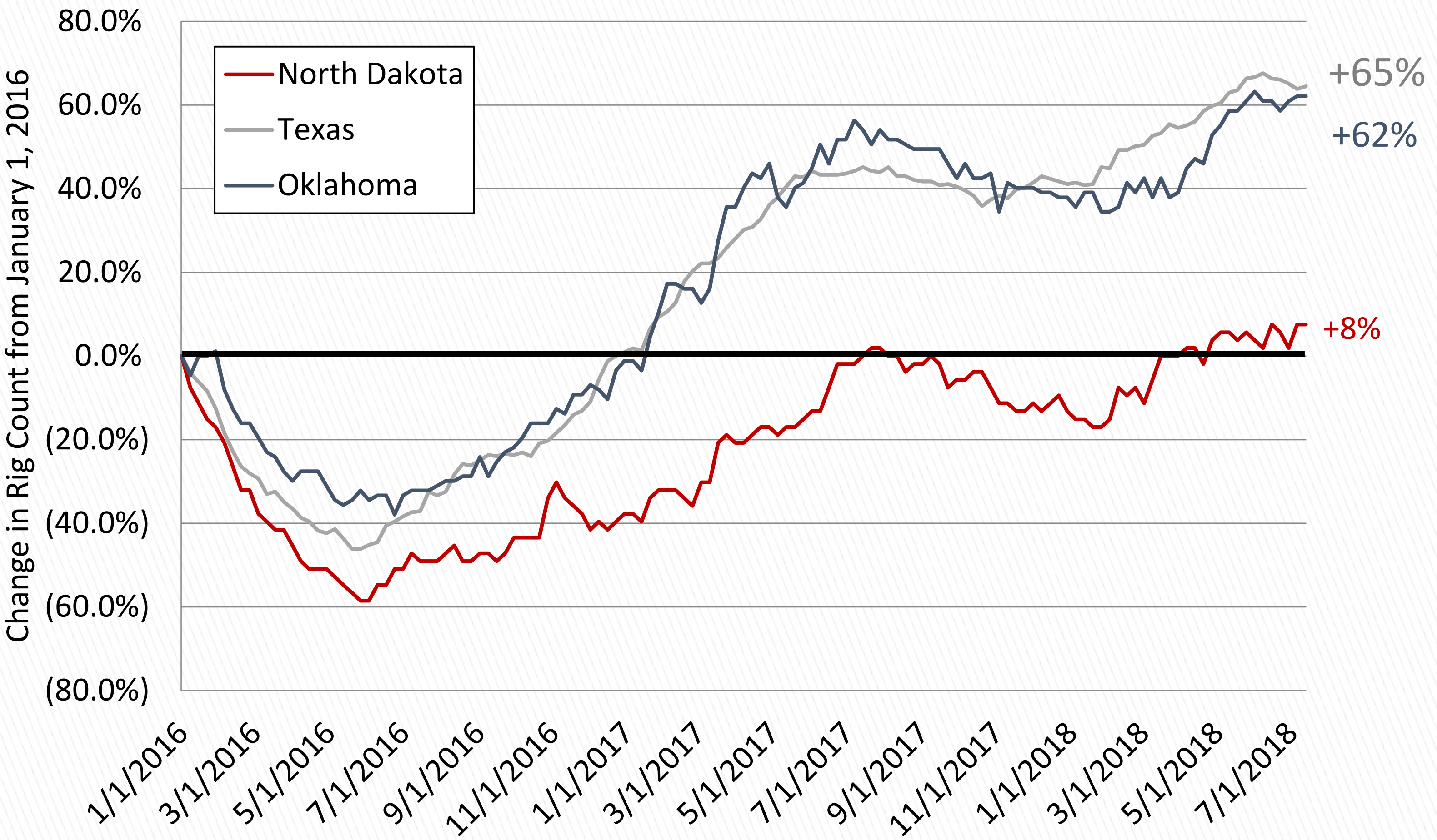
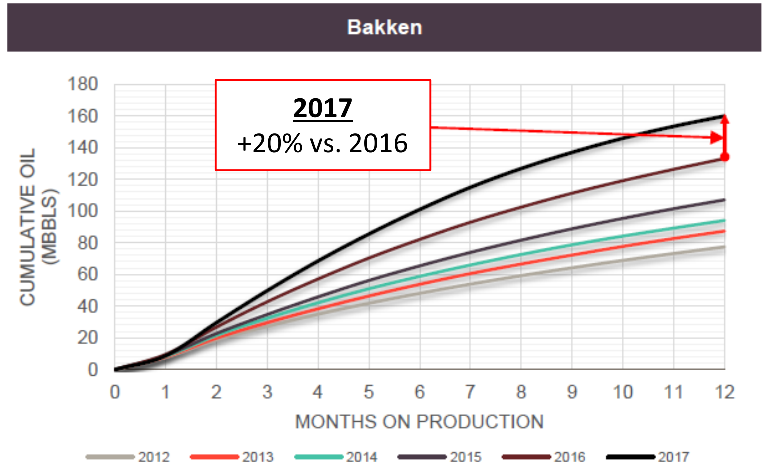
Change in Rig Count from January 1, 2016

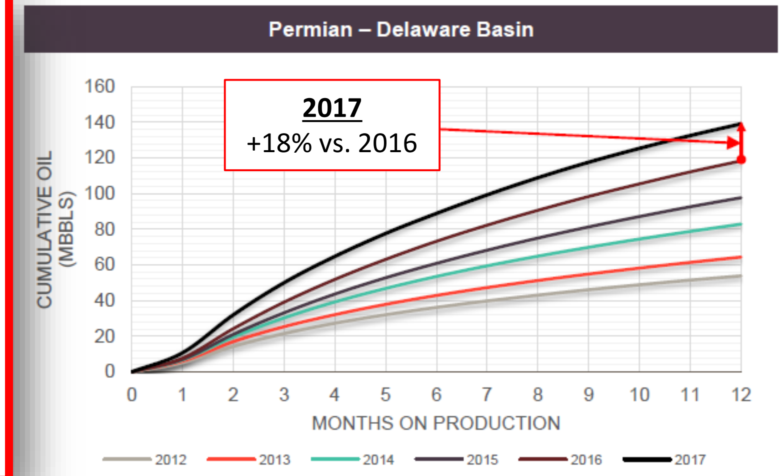


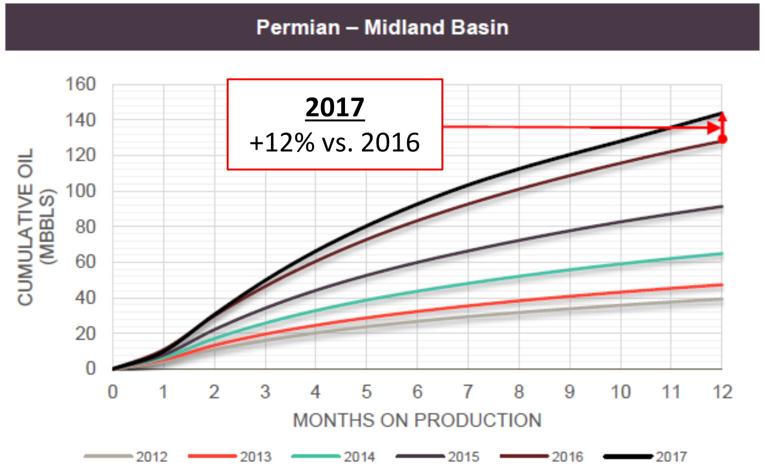
Source: Bloomberg and Company filings.

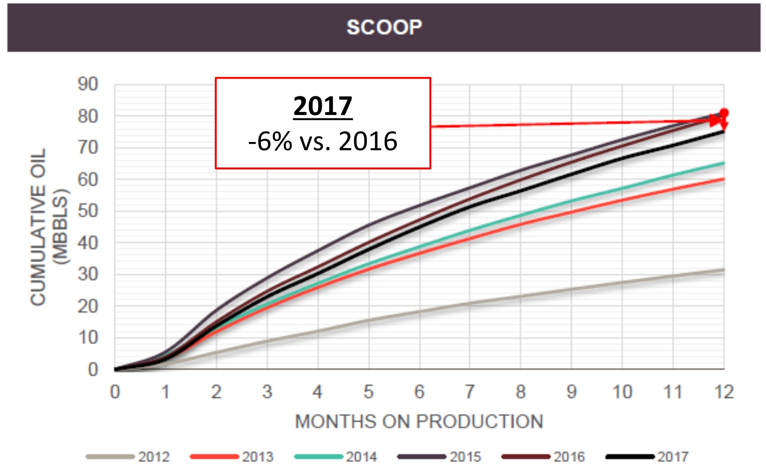
Bakken Outperforms Other Shale Plays

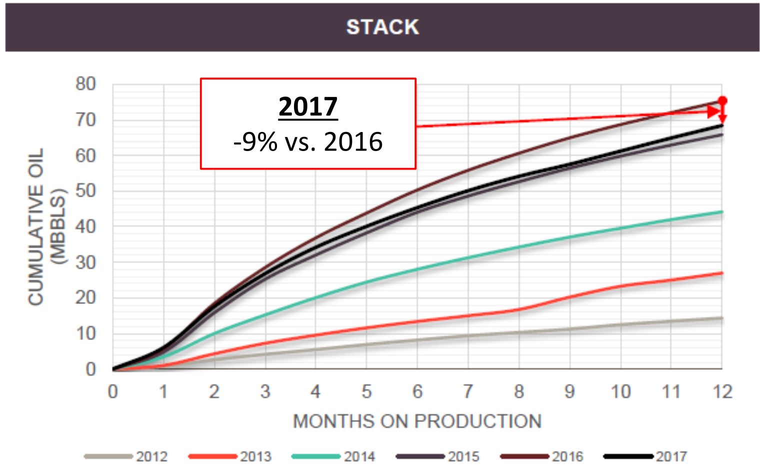
Bakken Achieves Best Year Productivity Gains in 2017

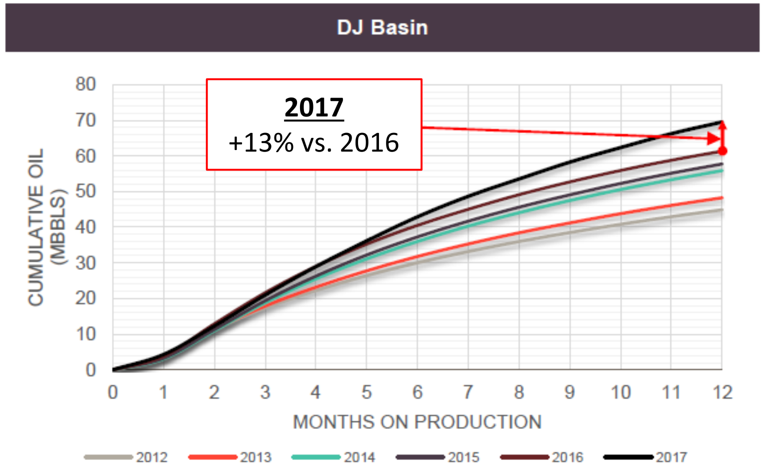








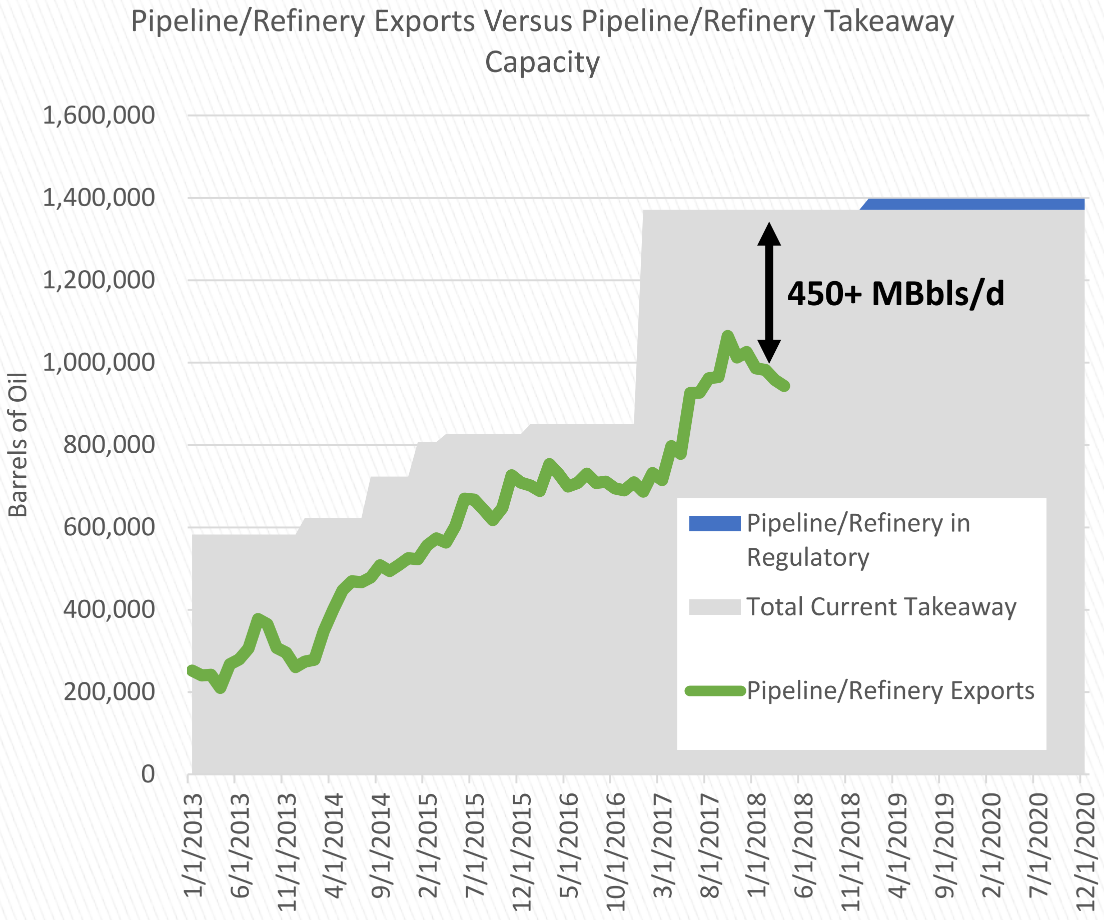


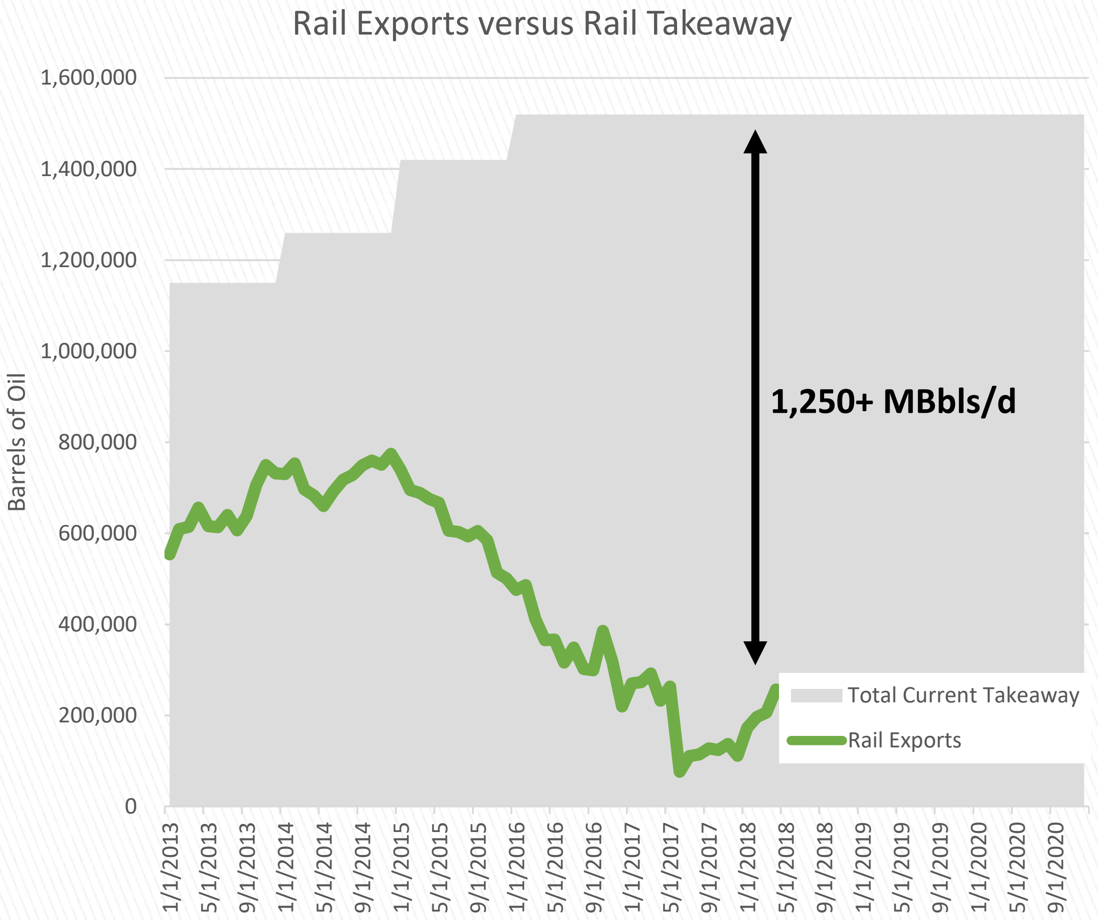


Source: Seaport Global SGS Productivity Analysis April 18, 2018

Excess Takeaway Capacity out of the Basin

Over 1,700 MBbl/d of additional takeaway capacity in the basin.

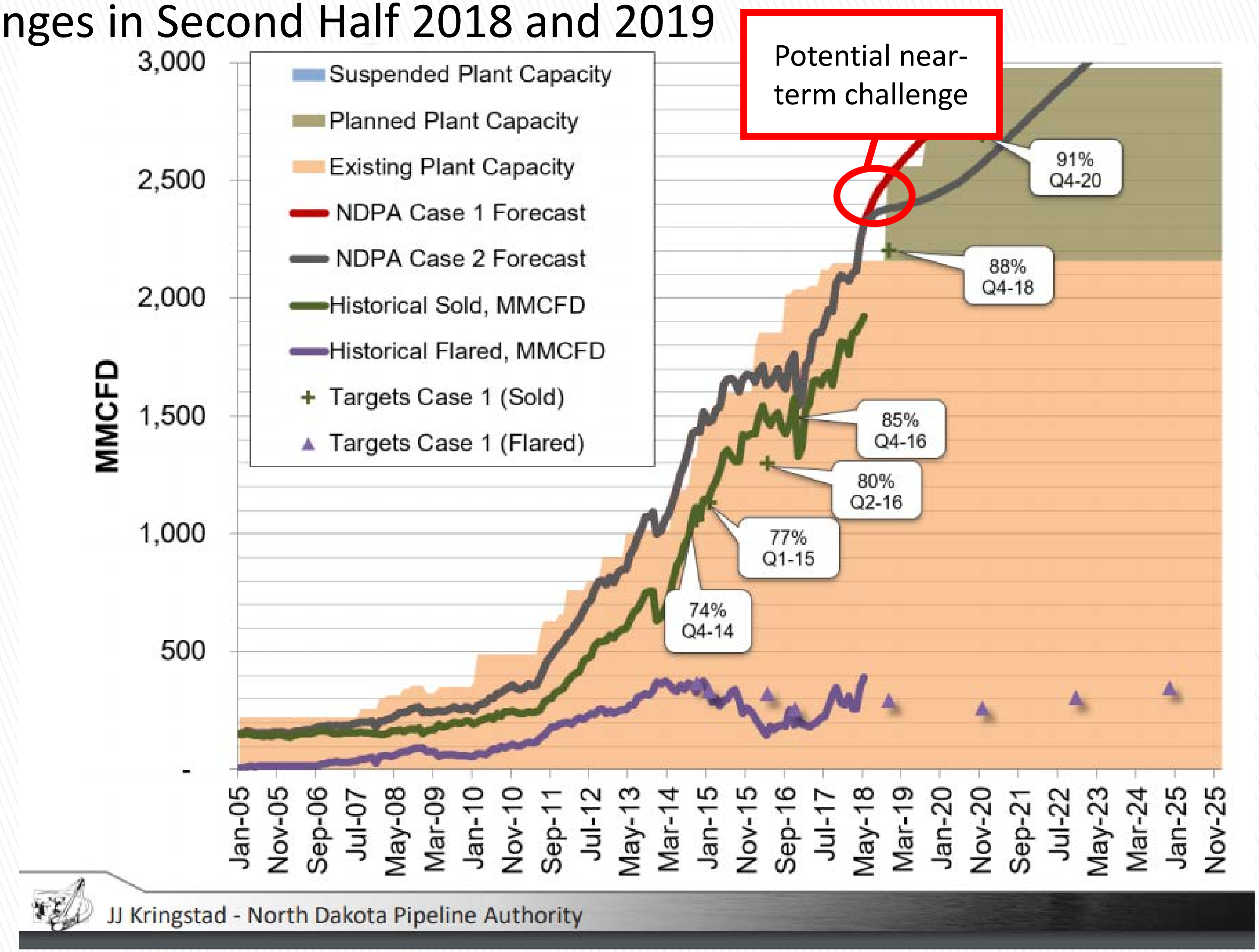




Source: EIA, North Dakota Pipeline Authority.

Infrastructure Build-out Meets Long-Term Goal

Near-term Challenges in Second Half 2018 and 2019



Source: North Dakota Pipeline Authority July 13, 2018 presentation.

Reconciliation of Adjusted Net Income (Loss)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss) attributable to common shareholders	$ 2,120	$ (65,981)	$ 17,132	$ (152,938)
Adjustments:				
Amortization of deferred gain on sale	(2,925)	(3,240)	(5,829)	(6,582)
(Gain) loss on sale of properties	(1,090)	1,024	1,486	2,298
Impairment expense	8,260	18,943	18,310	33,646
Loss on extinguishment of debt	808	-	31,968	1,540
Total measure of derivative (gain) loss reported under U.S. GAAP	103,483	(20,163)	156,147	16,414
Total net cash settlements received (paid) on commodity derivatives during the period	(53,379)	4,588	(78,216)	6,058
Tax impact of adjustments above	-	(429)	-	(19,908)
Adjusted net income (loss) attributable to common shareholders (1)	$ 57,277	$ (65,258)	$ 140,998	$ (119,472)
Adjusted net income (loss) attributable to common shareholders per share, basic (2)	$ 0.63	$ (0.72)	$ 1.55	$ (1.32)
Adjusted net income (loss) attributable to common shareholders per share, diluted (2)	$ 0.62	$ (0.72)	$ 1.54	$ (1.32)

(1) Adjusted Net Income (Loss) Attributable to Common Shareholders is a non-GAAP financial measure. Management believes it provides useful information to investors for analysis of Whiting's fundamental business on a recurring basis. In addition, management believes that Adjusted Net Income (Loss) Attributable to Common Shareholders is widely used by professional research analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted Net Income (Loss) Attributable for Common Shareholders should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

(2) All per share amounts have been retroactively adjusted for the 2017 period to reflect the Company's one-for-four reverse stock split in November 2017.

Reconciliation of Discretionary Cash Flow

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net cash provided by operating activities	$ 310,413	$ 110,993	$ 543,280	$ 191,063
Operating cash outflow for settlement of commodity derivative contract	-	-	61,036	-
Exploration	4,974	6,352	9,671	12,490
Changes in working capital	(46,348)	22,003	(54,479)	118,384
Discretionary cash flow (1)	$ 269,039	$ 139,348	$ 559,508	$ 321,937

(1) Discretionary cash flow, discretionary cash flow in excess of capital expenditures and operating cash flow in excess of capital expenditures are non-GAAP measures. Such measures are presented because management believes they provide useful information to investors for analysis of the Company's ability to internally fund acquisitions, exploration and development. Such measures should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

Reconciliation of Discretionary Cash Flow and Operating Activities in Excess of Capex

	Three Months Ended			
	December 31, 2017	March 31, 2018	June 30, 2018	Total
Net cash provided by operating activities	$ 286,703	$ 232,867	$ 310,413	$ 829,983
Operating cash outflow for settlement of commodity derivative contract	-	61,036	-	61,036
Exploration	16,801	4,697	4,974	26,472
Changes in working capital	(36,621)	(8,131)	(46,348)	(91,100)
Discretionary cash flow [1]	$ 266,883	$ 290,469	$ 269,039	$ 826,391
Capital expenditures	$ (170,757)	$ (187,144)	$ (203,250)	$ (561,151)
Discretionary cash flow in excess of capital expenditures [1]	$ 96,126	$ 103,325	$ 65,789	$ 265,240

	Three Months Ended June 30, 2018	Nine Months Ended June 30, 2018
Net cash provided by operating activities	$ 310,413	$ 829,983
Capital expenditures	(203,250)	(561,151)
Operating cash flow in excess of capital expenditures [1]	$ 107,163	$ 268,832

(1) Discretionary cash flow, discretionary cash flow in excess of capital expenditures and operating cash flow in excess of capital expenditures are non-GAAP measures. Such measures are presented because management believes they provide useful information to investors for analysis of the Company's ability to internally fund acquisitions, exploration and development. Such measures should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under U.S. GAAP and may not be comparable to other similarly titled measures of other companies.