eog resources

2Q 2018

NYSE Stock Symbol: EOG
Common Dividend: $0.88
Common Shares Outstanding: 579 Million

http://www.eogresources.com

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- *the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;*
- *the extent to which EOG is successful in its efforts to acquire or discover additional reserves;*
- *the extent to which EOG is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;*
- *the extent to which EOG is successful in its efforts to market its crude oil and condensate, natural gas liquids, natural gas and related commodity production;*
- *the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, transportation and refining facilities;*
- *the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;*
- *the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;*
- *EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;*
- *the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;*
- *competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties, employees and other personnel, facilities, equipment, materials and services;*
- *the availability and cost of employees and other personnel, facilities, equipment, materials (such as water) and services;*
- *the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;*
- *weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression and transportation facilities;*
- *the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;*
- *EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;*
- *the extent to which EOG is successful in its completion of planned asset dispositions;*
- *the extent and effect of any hedging activities engaged in by EOG;*
- *the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;*
- *political conditions and developments around the world (such as political instability and armed conflict), including in the areas in which EOG operates;*
- *the use of competing energy sources and the development of alternative energy sources;*
- *the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;*
- *acts of war and terrorism and responses to these acts;*
- *physical, electronic and cyber security breaches; and*
- *the other factors described under ITEM 1A, Risk Factors, on pages 14 through 23 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.*

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the duration and extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

Oil and Gas Reserves; Non-GAAP Financial Measures: The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve estimates provided in this presentation that are not specifically designated as being estimates of proved reserves may include "potential" reserves and/or other estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.

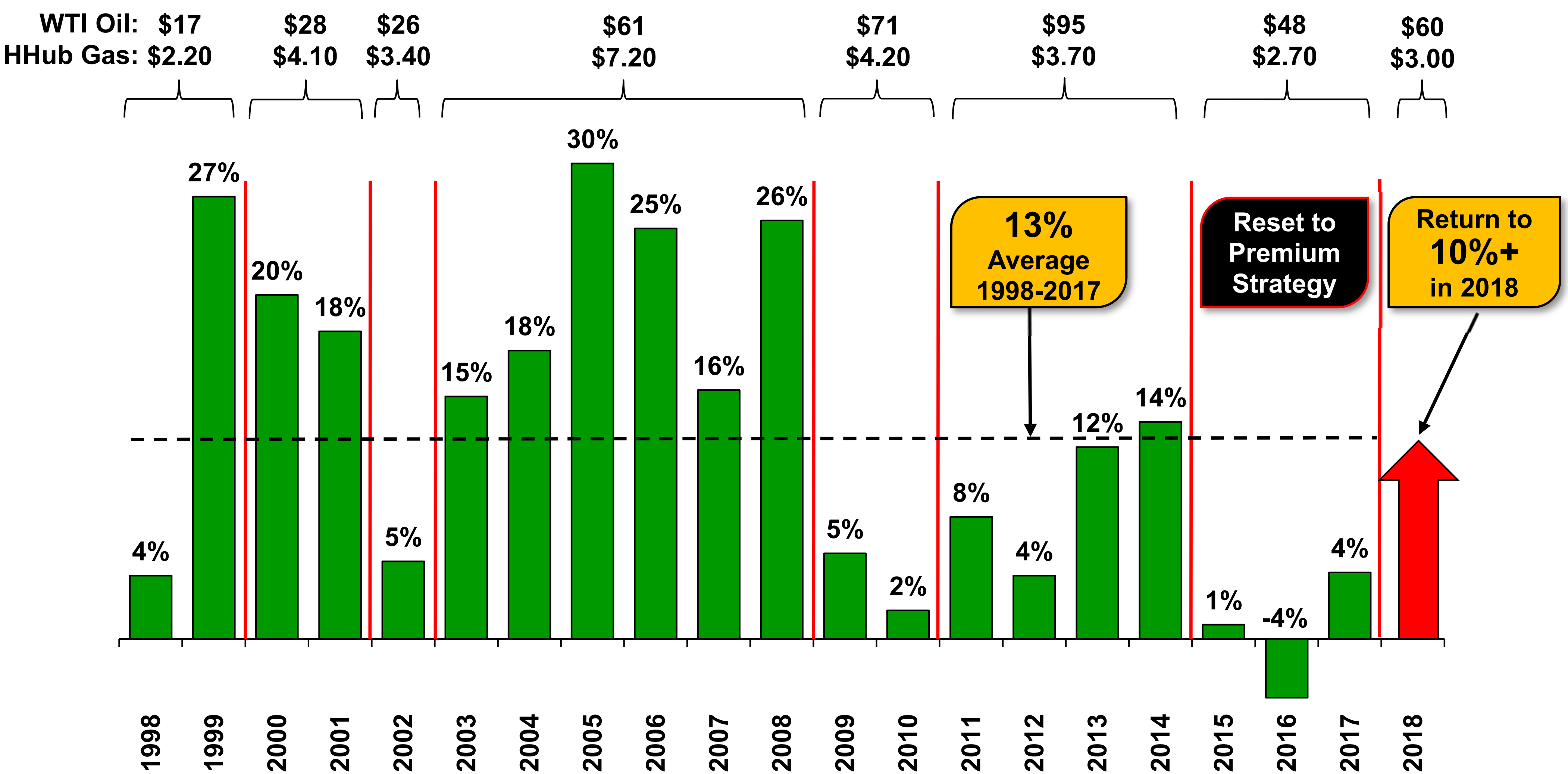
EOG Resources
"High Return Organic Growth Company"

- Leader in ROCE Through Commodity Price Cycles
- Leader in Disciplined Growth
- Low-Cost Producer Competitive in Global Oil Market
- Commitment to Safety and the Environment

Delivering Long-Term Shareholder Value

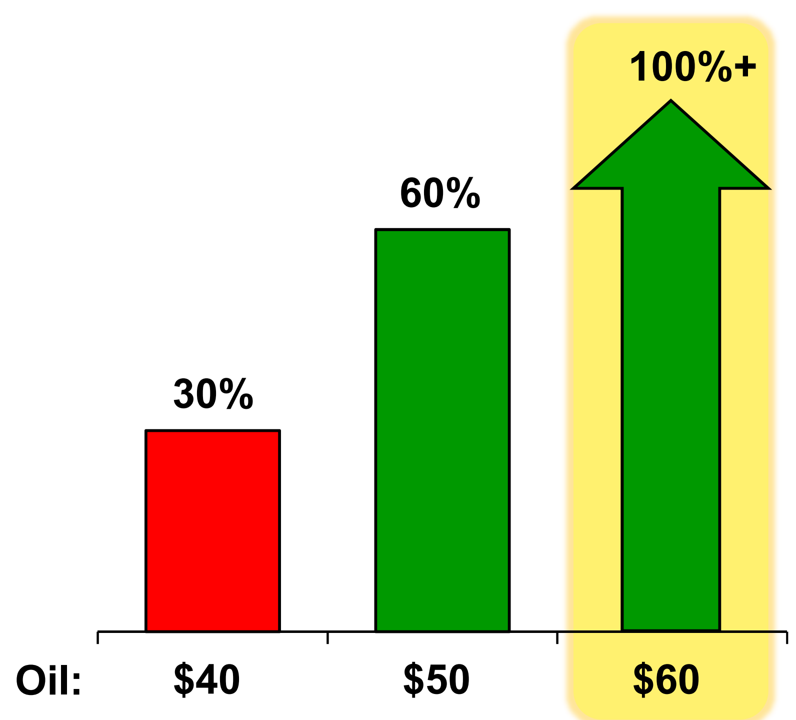
Focused on Returns

Return on Capital Employed[1]



(1) ROCE in 2013 and prior years calculated using reported net income (GAAP) and 2014 – 2017 using adjusted net income (Non-GAAP). See reconciliation schedules.

Premium Drilling = Leading Returns



(1) See reconciliation schedules.

- Industry-Leading Cash Returns
- Payback Period <1 Year at $60 Oil
- Finding Cost Does Not Increase with Oil Price
- ROCE Competitive with All Sectors

9.2 BnBoe[2] ≈ 9,500 Net Undrilled Locations > 13 Years of Drilling

(2) Estimated potential reserves net to EOG, not proved reserves.

Premium Drilling Drives Peer-Leading Performance

>100%
Premium Well Direct ATROR[1] at $60 Oil

17-19%
Oil Growth[3]

>$1.5 Billion
Free Cash Flow[4] at $60 Oil

Reduce Well Costs[2]
5%

Reduce Cash Operating Expenses[3]
6%

Low Finding Cost Reduces DD&A Rate[3]
15%

Double-Digit ROCE in 2018

(1) See reconciliation schedules.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.
(3) Based on 2018 guidance, as of August 2, 2018. Cash Operating Expenses include LOE, Transportation and G&A. See slide 18 also.
(4) Discretionary Cash Flow less CAPEX and Dividend. Based on midpoint of 2018 guidance, as of August 2, 2018. See reconciliation schedules for reconciliations and definitions of non-GAAP measures.

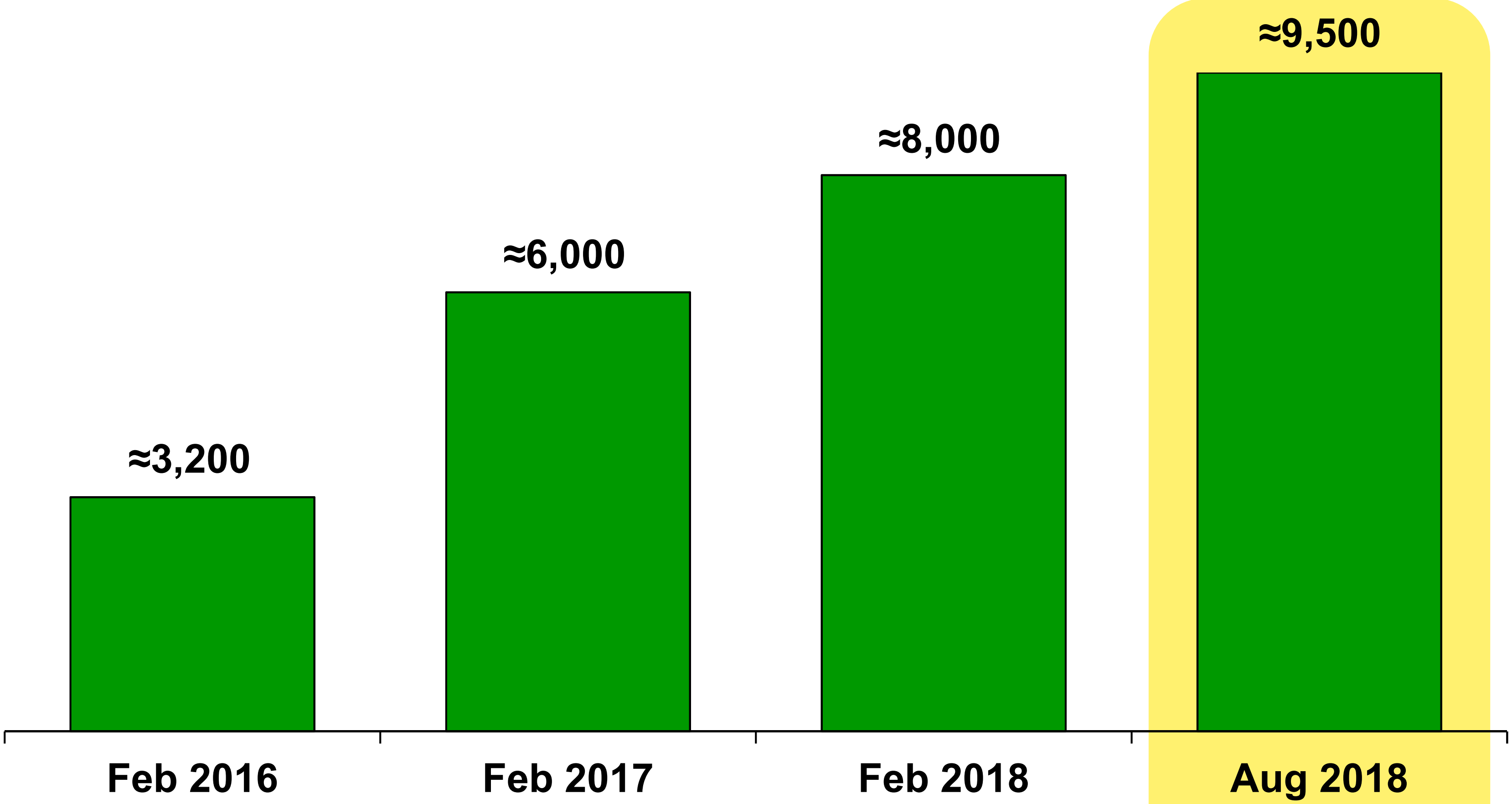
2Q 2018
New Premium Resource Potential and Strong Execution

- Announced Two New Premium Resource Plays and Expanded Turner Sand Inventory
  - Powder River Basin – Mowry Shale
  - Powder River Basin – Niobrara Shale
  - Added 1,560 Net Locations to Premium Inventory
- Increased Total Premium Resource Potential ~26% to 9.2 BnBoe[1]
- Strong Operational Execution
  - Exceeded Midpoint of All Total Production Targets
  - Total Per-Unit Operating Cost Below Target
  - Maintain Target of Reducing Well Costs[2] 5% in 2018
- Increased Dividend
  - Cash Dividend of $0.88[3] per Share, +31% Year-Over-Year
- Earning 140% Direct ATROR[4] on YTD Investments
- On Track with Full-Year $5.4 - $5.8 Billion CAPEX Budget

Disciplined Growth, Return Focused Strategy

(1) Estimated potential reserves net to EOG, not proved reserves.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.
(3) Indicated annual rate, as of August 2, 2018.
(4) See reconciliation schedules. Based on NYMEX strip prices as of July 2018.

Adding Premium Locations[1] Faster Than Drilling



	Feb 2016	Feb 2017	Feb 2018	Aug 2018
Resource Potential[2]	2.0 BnBoe	5.1 BnBoe	7.3 BnBoe	9.2 BnBoe
Per Well	625 MBoe	850 MBoe	900 MBoe	970 MBoe

Replaced > 2x Planned 2018 Completions YTD

(1) Premium locations are shown on a net basis and are all undrilled.
(2) Estimated potential reserves net to EOG, not proved reserves.

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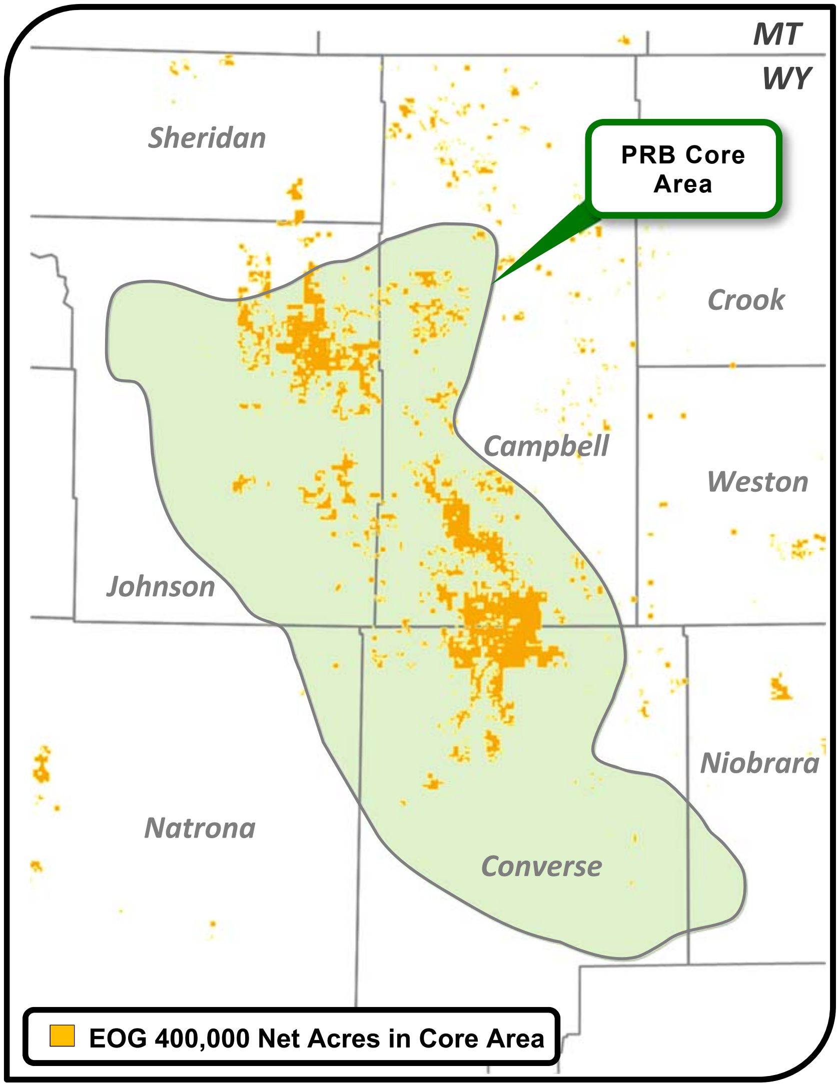
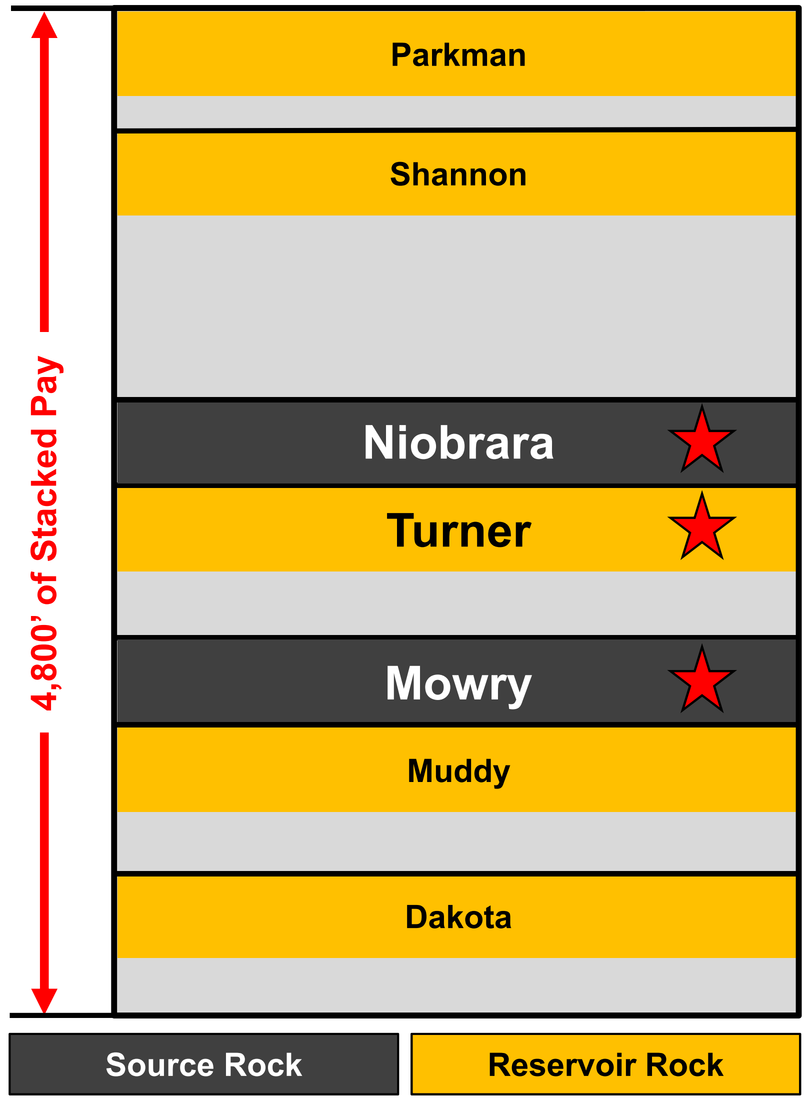
Powder River Basin
Significant Resource Potential Across Multiple Plays





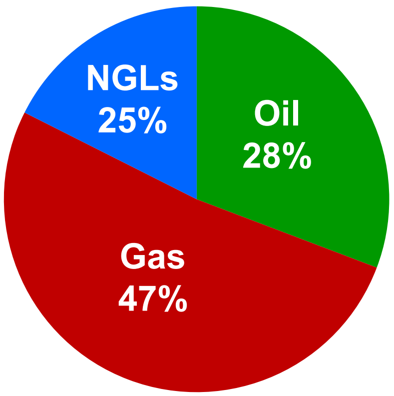
Powder River Basin

- Net Resource Potential 2.1 BnBoe[1]
  - 1,845 Net Locations, Average 70% Working Interest and 58% Net Revenue Interest
- Average 2 Rigs and 1 Completion Spread Operating in 2018
- Complete ≈ 45 Net Wells in 2018 vs. 39 in 2017
- Average 49°API Oil
- Operatorship on 85% of Core Premium Acreage
  - Permits Secured to Support Development Plan and Operational Flexibility
- Consolidated 90,000 Net Acres Through Recent Trades

Mowry Shale

- 141,000 Net Acres Prospective in Powder River Basin
  - 880 Total Net Locations; ≈ 660’ Spacing
- Estimated Resource Potential 1,230 MMBoe[1], Net to EOG
- Typical Well
  - EUR 1,700 MBoe, Gross; 1,400 MBoe, NAR
  - Well Cost[2] Target $6.1MM for 9,500’ Lateral

	Bopd	Boed	Lateral
2Q 2018 2 Gross Wells 30-Day IP	760	2,190	9,100’



Typical EOG Mowry Well EUR

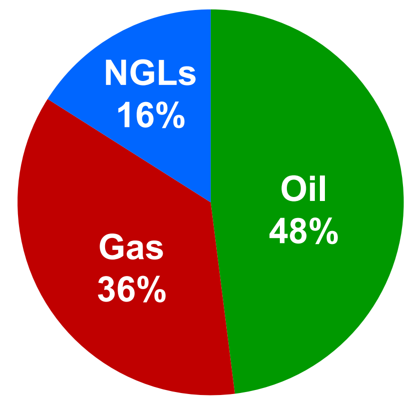
(1) Estimated potential reserves net to EOG, not proved reserves. Includes (i) 92 MMBoe of proved reserves across all Powder River Basin plays, including 1.5 MMBoe of proved reserves in the Mowry, in each case booked at December 31, 2017 and (ii) prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

Powder River Basin

Niobrara Shale

- 89,000 Net Acres Prospective in Powder River Basin
  - 560 Total Net Locations; ≈ 660' Spacing
- Estimated Resource Potential 640 MMBoe[1], Net to EOG
- Typical Well
  - EUR 1,400 MBoe, Gross; 1,150 MBoe, NAR
  - Well Cost[2] Target $5.9MM for 9,500' Lateral

	Bopd	Boed	Lateral
Ballista 213-1301H 30-Day IP	1,180	2,090	9,500'

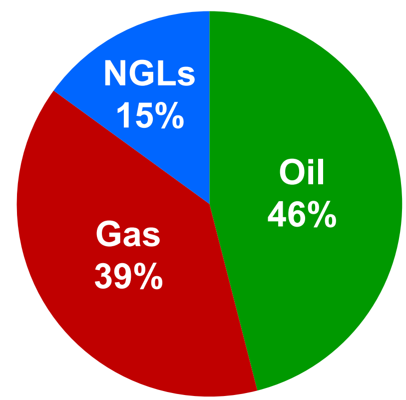


Typical EOG Niobrara Well EUR

Turner Sand

- 169,000 Net Acres Prospective in Powder River Basin
  - 405 Total Net Locations, ≈ 1,700' Spacing
- Estimated Resource Potential 200 MMBoe[1], Net to EOG
- Typical Well
  - EUR 730 MBoe, Gross; 500 MBoe, NAR
  - Well Cost[2] Target $4.5MM for 8,000' Lateral

	Bopd	Boed	Lateral
Falcon 3-3410H 30-Day IP	1,465	1,635	9,300'



Typical EOG Turner Well EUR

(1) Estimated potential reserves net to EOG, not proved reserves. Includes (i) 5.1 MMBoe of proved reserves in the Niobrara and 72.2 MMBoe of proved reserves in the Turner booked at December 31, 2017 and (ii) prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

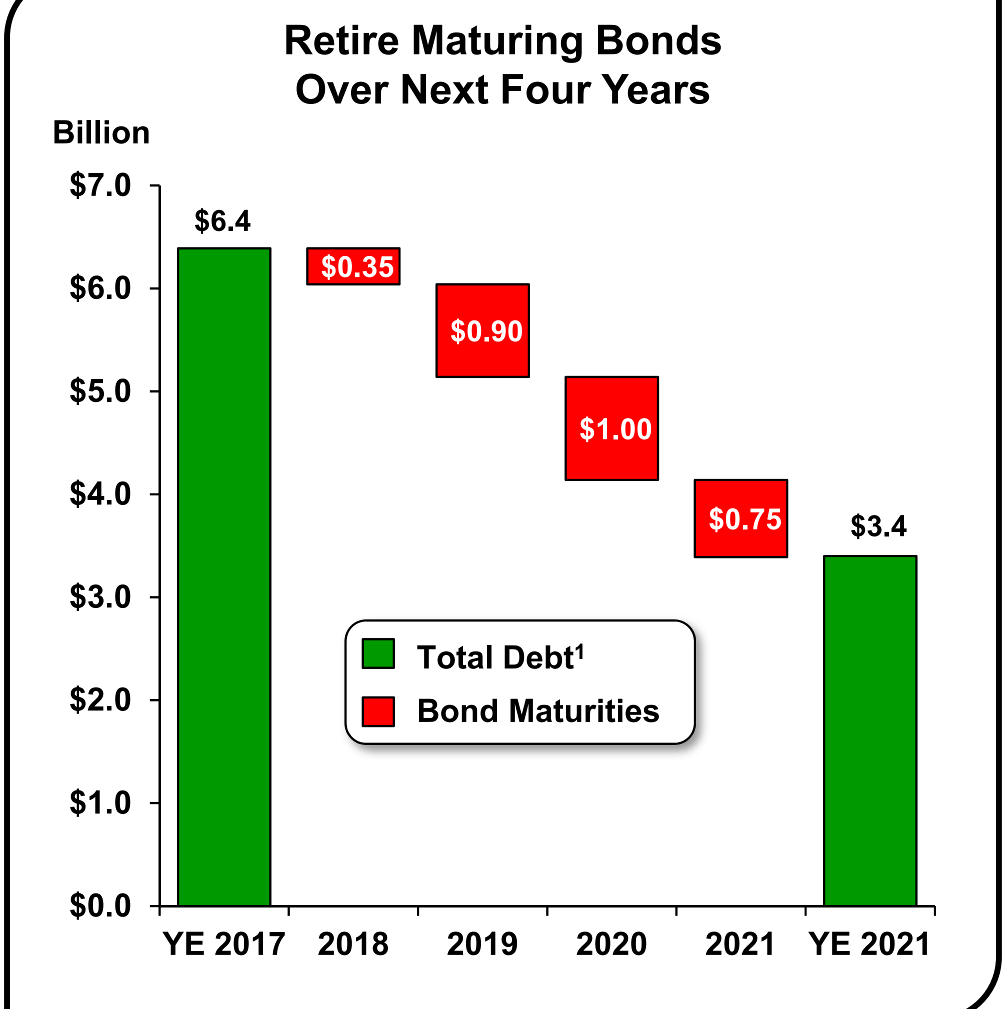
Cash Flow Priorities
Aligned with Long-Term Shareholder Value

- Disciplined Reinvestment in High-Return Organic Growth
  - Diverse and Deep Premium Drilling Inventory
  - Exploration & Low-Cost Leasing for New High-Return Plays
- Balance Sheet Provides Flexibility through Commodity Price Cycles
  - Target $3 Billion Total Debt[1] Reduction Over Next Four Years
- Deliver Stronger Dividend Growth
  - 2018 Dividend Growth of 31%[2] Above Historical 19% CAGR
- No Change in Stringent Investment Criteria
  - No Expensive Corporate M&A
  - Pursue Opportunistic Low-Cost Property Additions
  - All Expenditures Must Compete with Organic Reinvestment

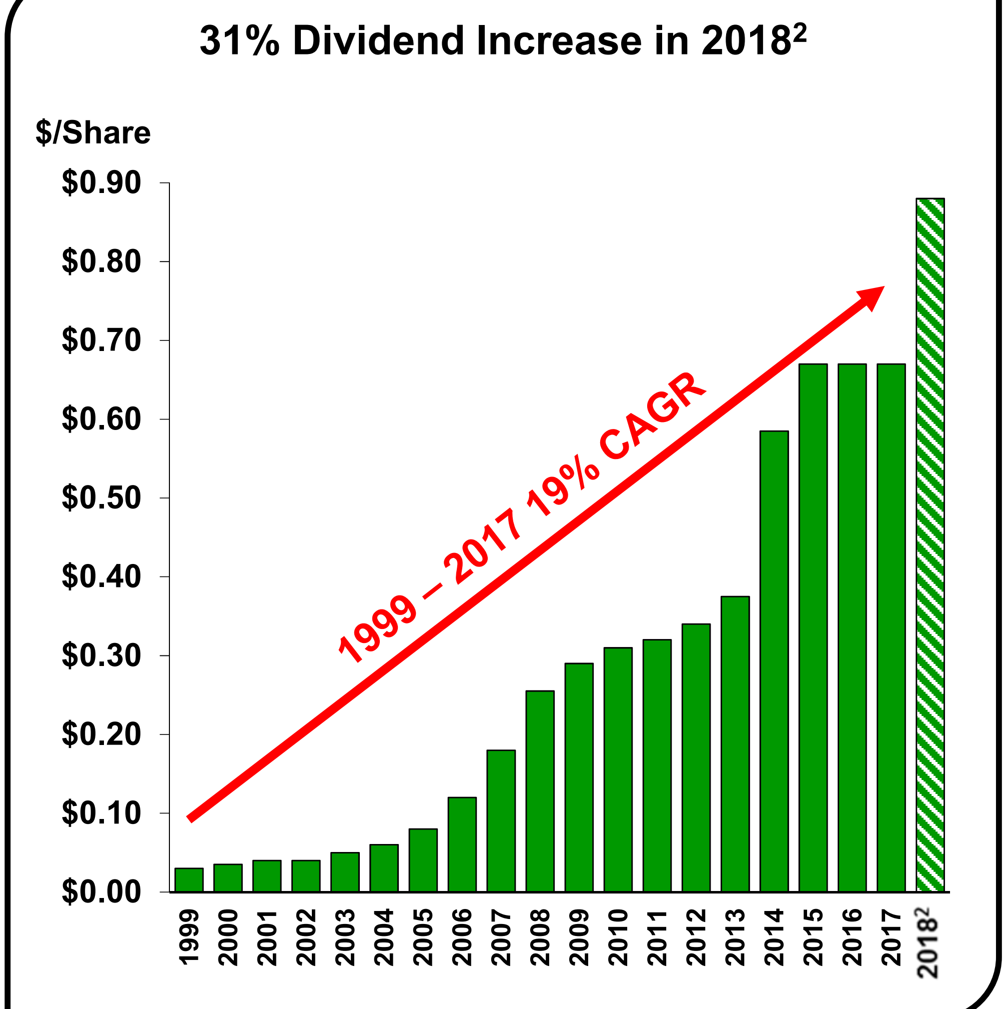
(1) Current and long-term debt.
(2) Indicated annual rate, as of August 2, 2018.

Balance Debt Reduction & Dividend Growth

Target $3 Billion Reduction in Total Debt[1]

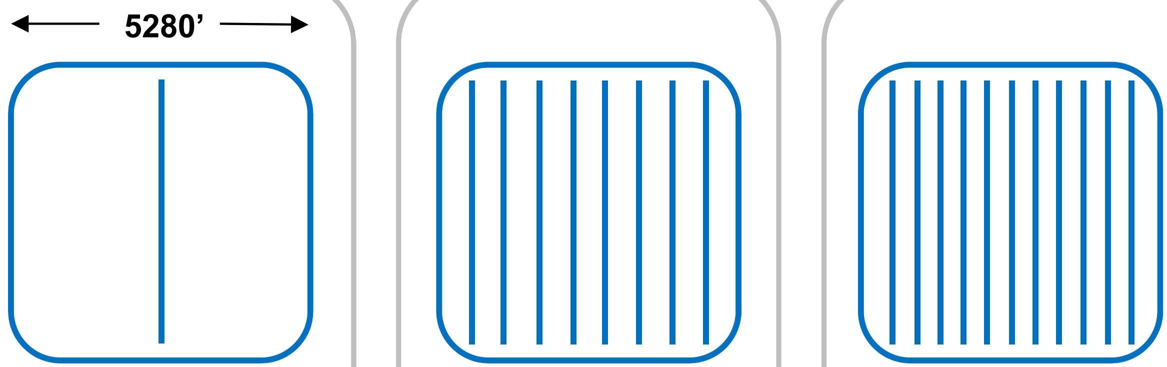


Target Stronger Dividend Growth



(1) Current and long-term debt.
(2) Indicated annual rate, as of August 2, 2018.
Note: Dividends adjusted for 2-for-1 stock splits effective March 1, 2005 and March 31, 2014.

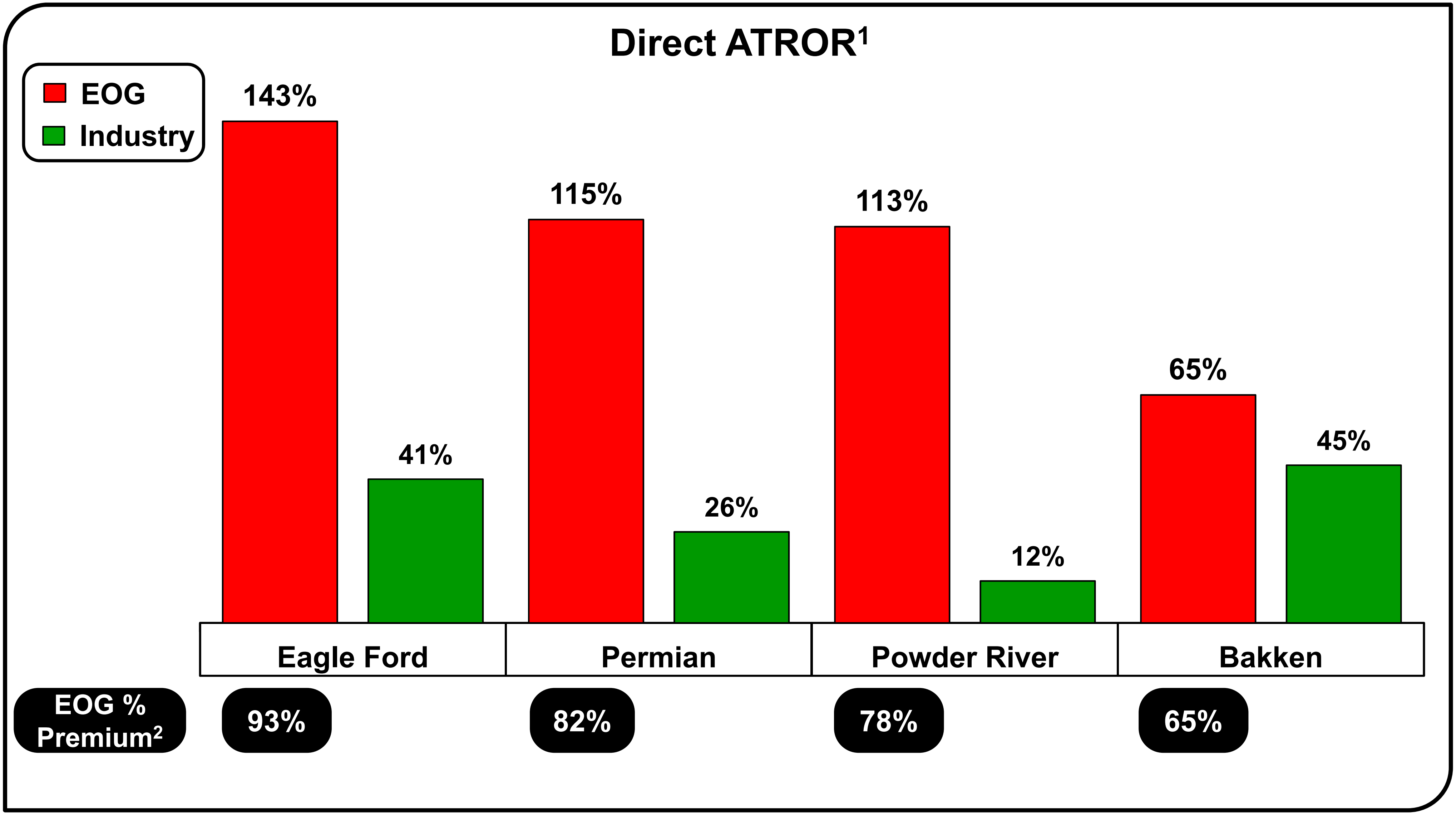
Maximizing NPV of the Field vs. Single Well Economics[1]



	5,000’ Lateral	5,000’ Lateral	5,000’ Lateral
Well Spacing	5,280’	660’	440’
Est. Reserves per Section[2]	1,250 MBOE	7,850 MBOE	9,900 MBOE
Completed Well Cost[3]	$5.9 MM	$5.9 MM	$5.9 MM
NPV per Section[4]	$5.7 MM	$28.5 MM	$31.0 MM
Direct ATROR[5]	72%	50%	40%
IP30, Boed	2,500	2,300	2,000

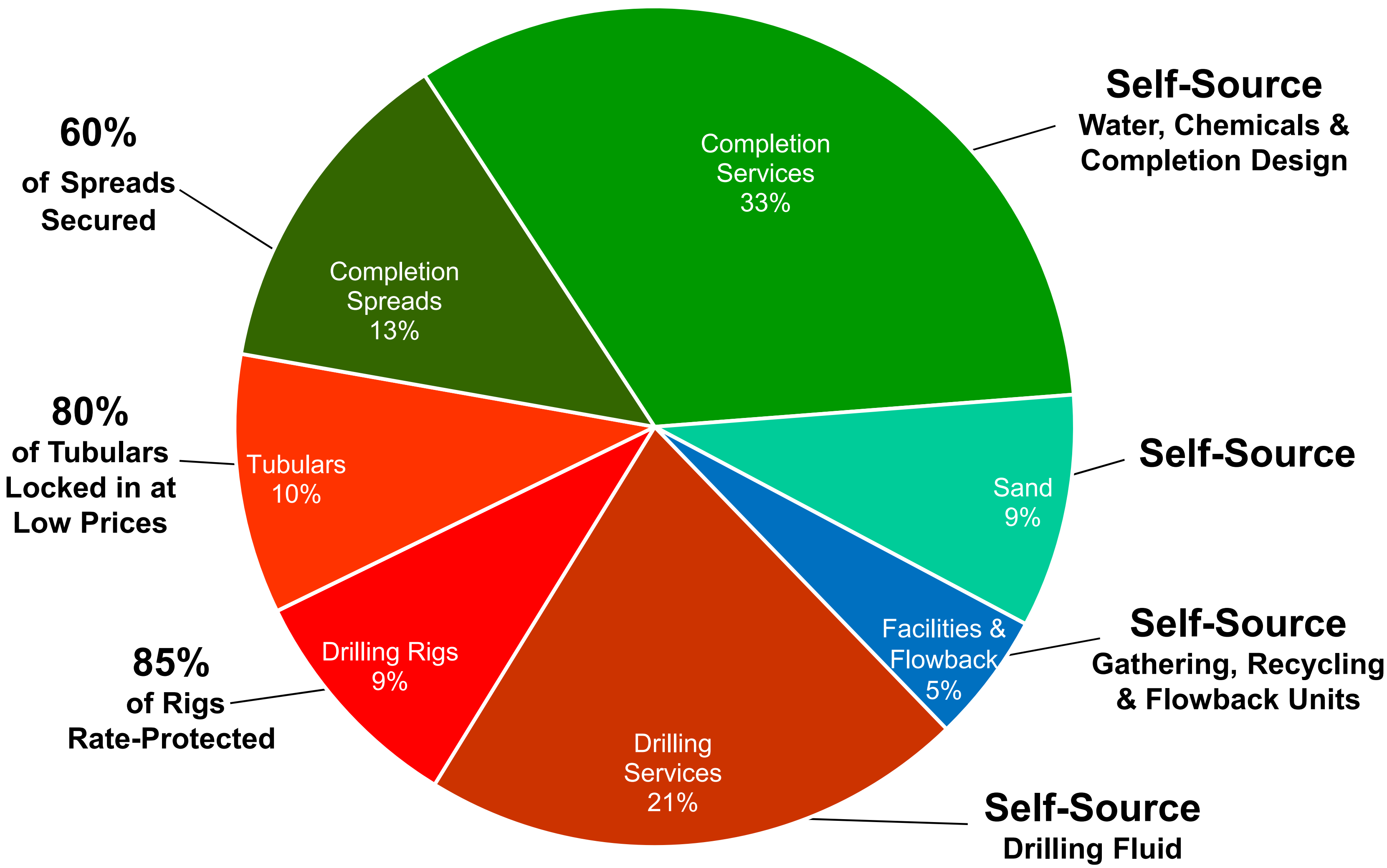
(1) Analysis based on Delaware Basin wells.
(2) Section = 640 acres, 1 square mile.
(3) Includes drilling, completion, well-site facilities and flowback. This analysis does not consider potential cost savings from larger scale development.
(4) NPV calculated using $40 WTI and $2.50 NYMEX fixed for life of wells.
(5) Direct ATROR calculated using $40 WTI and $2.50 NYMEX fixed for life of well. See reconciliation schedules.

EOG's 2017 Returns vs. Industry by Play



(1) ATROR calculated using $50 WTI and $3.00 NYMEX fixed for life of well.
Assumes industry capital and operating costs equal to EOG. See reconciliation schedules.
All horizontal wells from original operator. Production data sourced from IHS.
(2) Percent of gross completed 2017 wells from each basin which are premium.

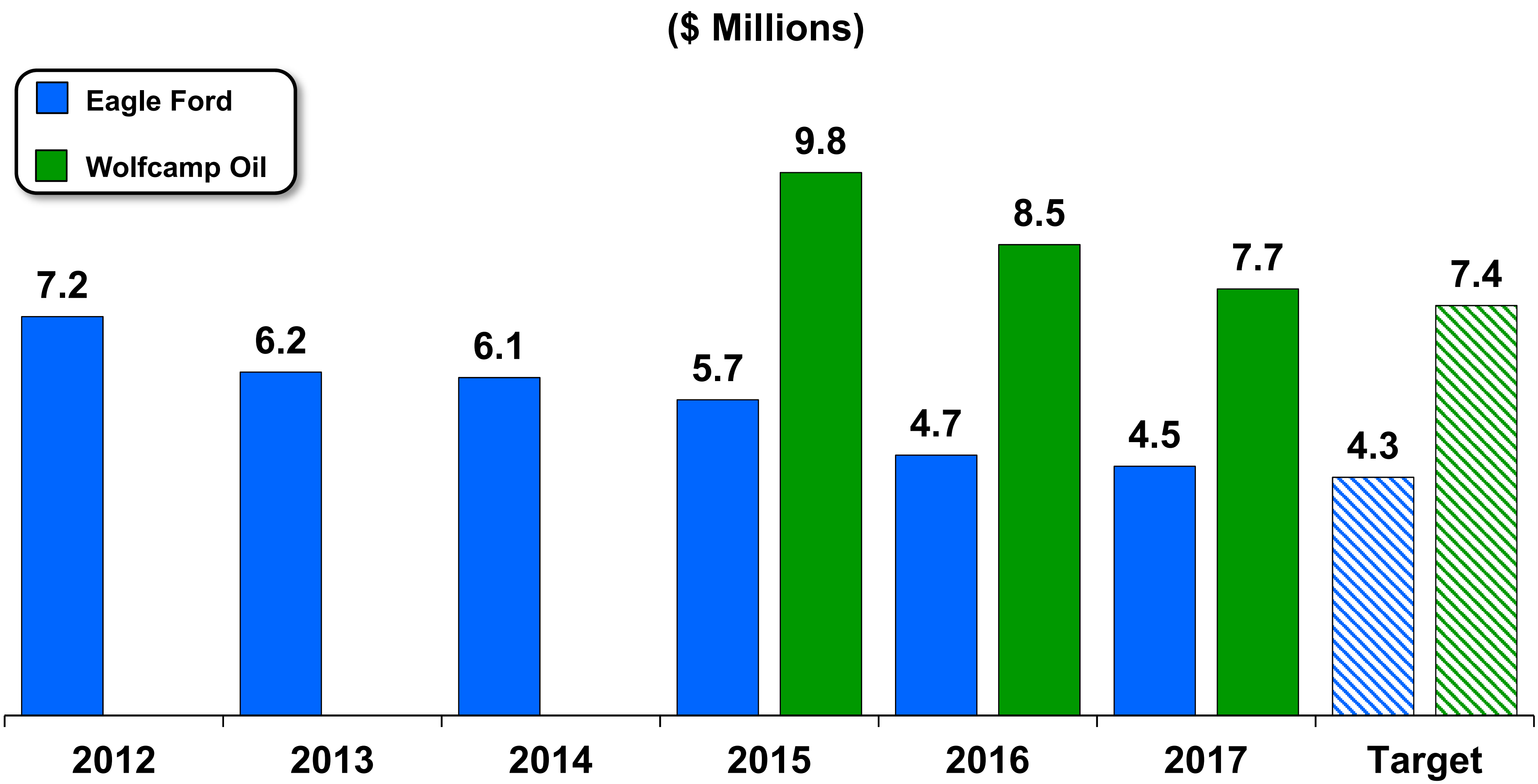
Secured ≈60% of 2018 Well Costs[1] at Competitive Pricing



Self-Source ≈25% of Well Costs[1]

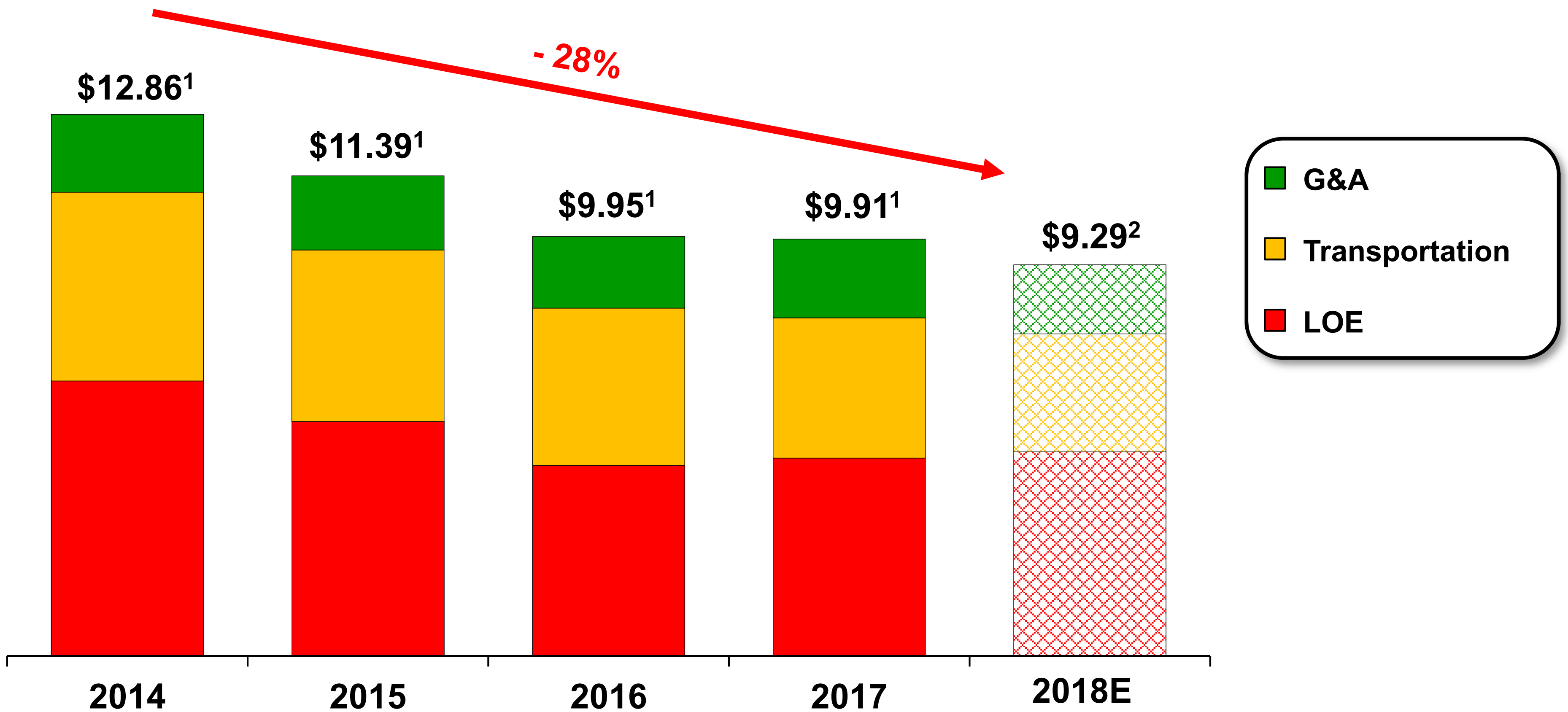
(1) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

Strong Track Record of Well Cost[1] Reduction in All Price Environments



(1) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback. Eagle Ford normalized to 5,300' lateral and Wolfcamp Oil normalized to 7,000' lateral.

Cash Operating Cost Reduction
($ Per BOE)

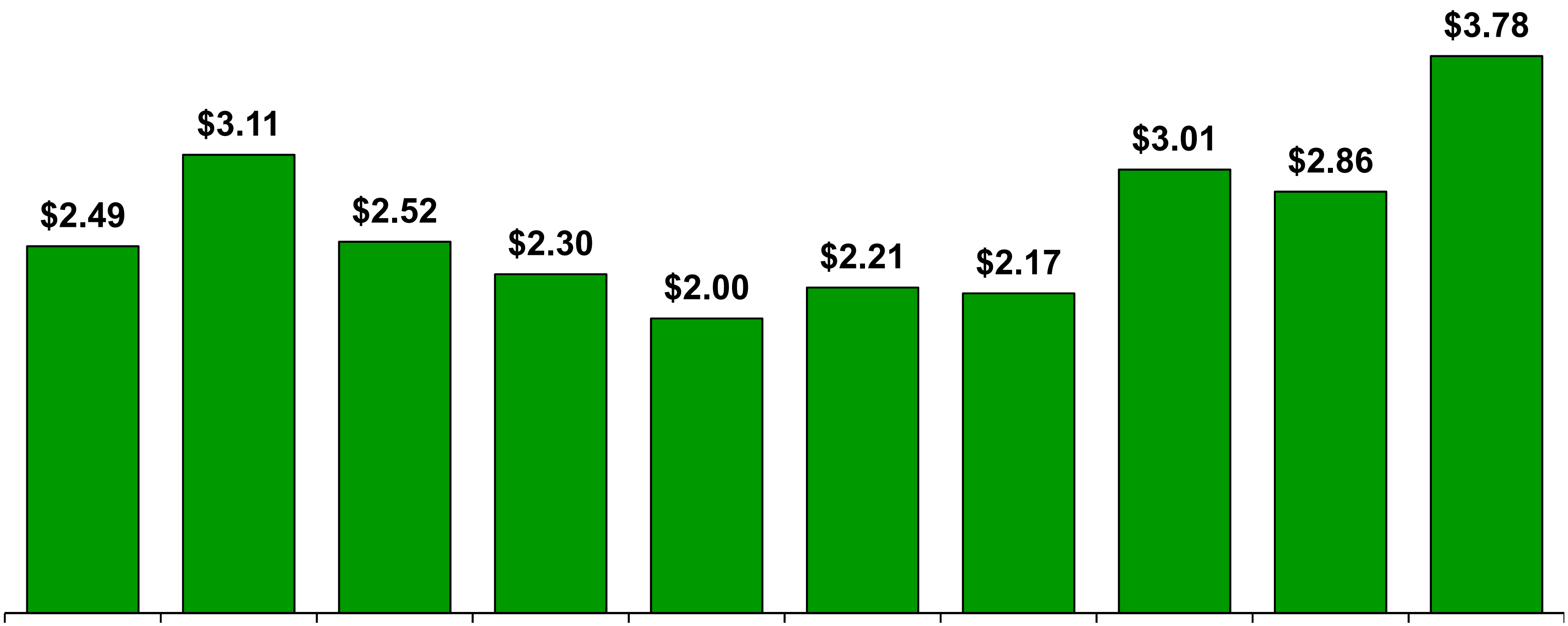


(1) Excludes one-time expenses. See reconciliation schedules.
(2) Based on midpoint of 2018 guidance, as of August 2, 2018.

EOG Realizes Higher Oil Prices than Peers

U.S. Crude Oil & Condensate Price Realization vs. Peers[1]
($/Bbl)

EOG Average ≈$2.65 per Bbl Advantage



	1Q 2016	2Q 2016	3Q 2016	4Q 2016	1Q 2017	2Q 2017	3Q 2017	4Q 2017	1Q 2018	2Q 2018[2]
EOG	$30.87	$43.87	$43.66	$47.93	$50.38	$47.51	$48.06	$56.95	$64.24	$67.91
Peers	$28.38	$40.76	$41.14	$45.63	$48.38	$45.30	$45.89	$53.94	$61.38	$64.13

(1) Difference in U.S. crude oil and condensate price realization between EOG and peer average. Peers include APA, APC, COP, DVN, HES, MRO, NBL and PXD. Source: Company filings.
(2) 2Q 2018 peer average excludes peers that have not disclosed 2Q 2018 realized price prior to August 2, 2018.

EOG's Culture Drives Sustainable Competitive Advantage

Culture

- Rate-of-Return Driven
- Decentralized / Non-Bureaucratic
- Multi-Disciplined Teamwork
- Innovative / Entrepreneurial
- Every Employee is a Business Person

Exploration

- Internal Prospect Generation
- First Mover Advantage
- Best Rock / Best Plays
- Low-Cost Acreage
- Most Prolific U.S. Horizontal Wells

Operations

- Fastest U.S. Horizontal Driller
- Industry Leading Completion Technology
- Self-Sourcing Materials / Services
- Low Infrastructure & Production Cost
- Proven Track Record of Execution

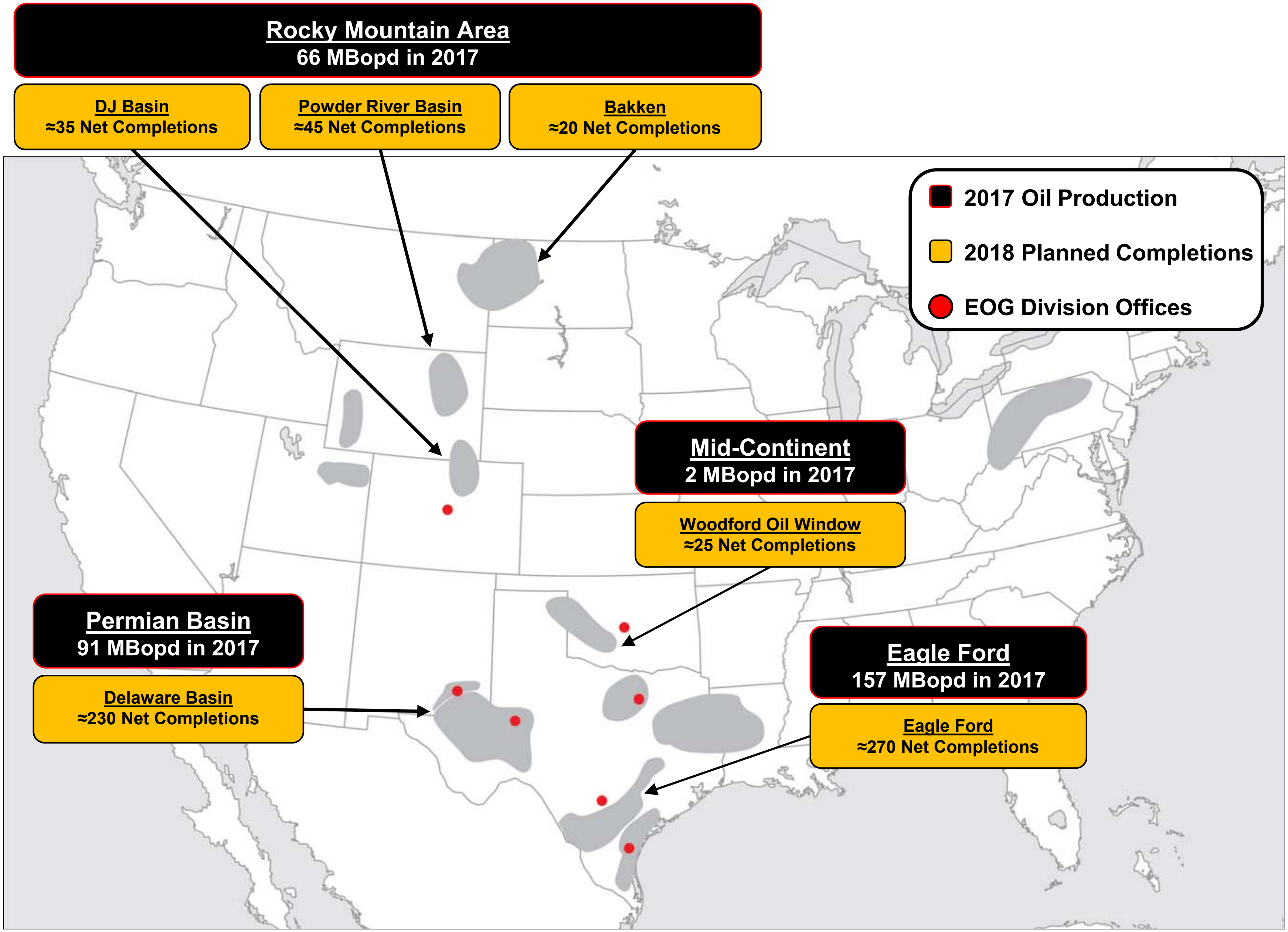
Information Technology

- Large Proprietary Data Marts
- Real-Time Data Capture
- Predictive Algorithms
- 65+ In-House Desktop / Mobile Apps
- Fast / Continuous Tech Advancement

High-Return Organic Oil Growth

Appendix

Premium Drilling in All Major U.S. Oil Basins



Deep Inventory of Crude Oil Assets

Play	Net Acres	Total Drilled & Undrilled Locations[1]	Resource Potential[2] (MMBoe)	Undrilled Premium Locations[3]
Eagle Ford	520,000	7,200	3,200	2,300
Delaware Basin				
- Wolfcamp	346,000	2,660	2,900	1,700
- First Bone Spring	100,000	555	540	540
- Second Bone Spring	289,000	1,870	1,400	1,300
- Leonard	160,000	1,800	1,700	1,275
Powder River Basin				
- Mowry	141,000	880	1,230	875
- Niobrara	89,000	560	640	555
- Turner	169,000	405	200	200
Bakken/Three Forks				
- Core	120,000	975	620	330
- Non-Core	100,000	1,125	400	-
DJ Basin	88,000	460	210	150
Woodford Oil Window	50,000	260	210	260
	≈2,170,000	≈ 18,750	≈ 13,300	≈ 9,500

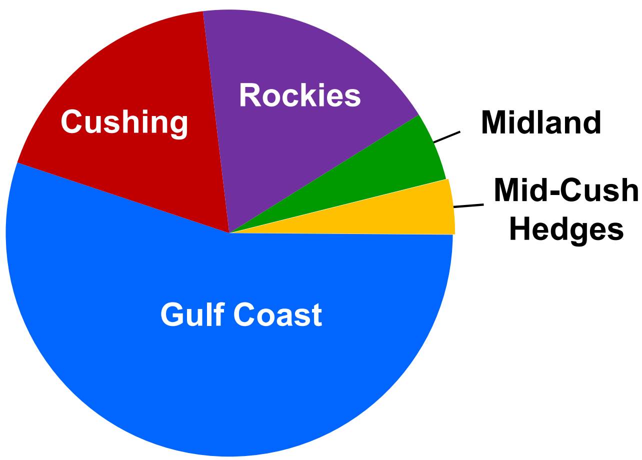
Inventory Growing in Quality and Size

(1) Number of producing and undrilled remaining net wells as of July 25, 2018. Assumes no further downspacing, acreage additions or enhanced recovery.
(2) Estimated potential reserves (MMBoe) net to EOG, not proved reserves. Includes proved reserves and prior production from existing wells.
(3) Premium locations are shown on a net basis.

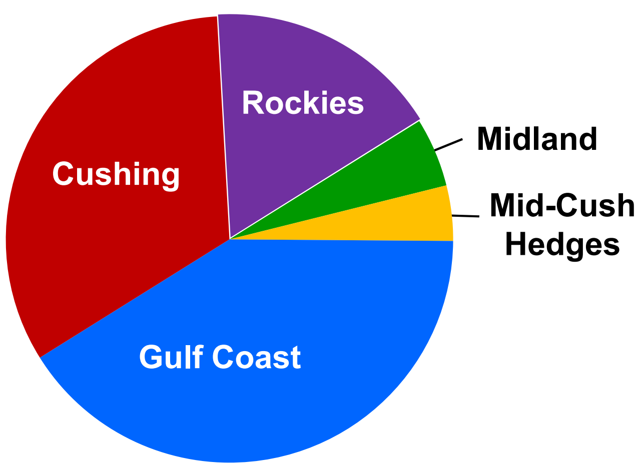
EOG's Diversified Marketing Options Provide Pricing Advantage & Flow Assurance

EOG U.S. Crude Oil Pricing

2018E

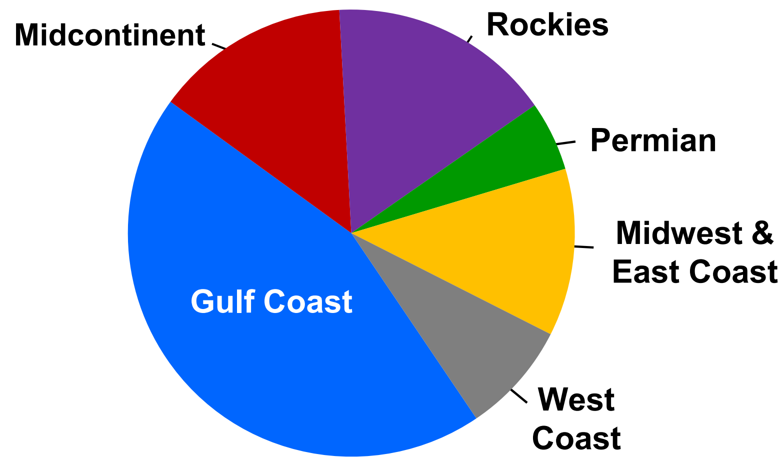


2019E

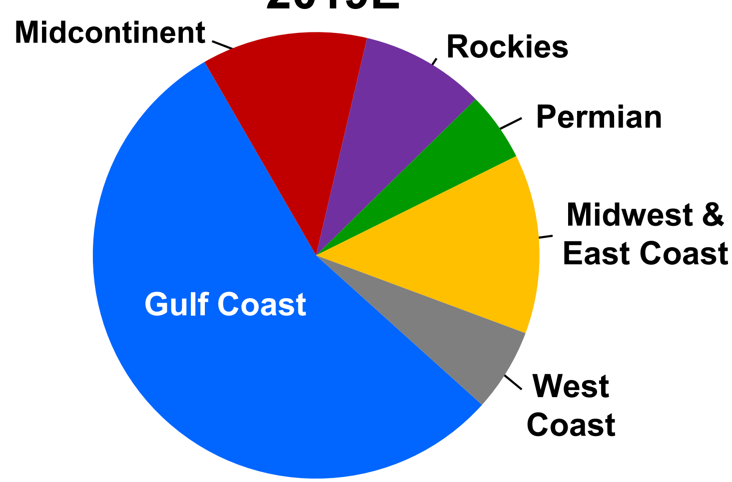


EOG U.S. Natural Gas Pricing

2018E



2019E



Permian Basin Takeaway
Positioned to Support Growth

- Align Volumes to Highest Value Markets
- Avoid Long-Term Commitments

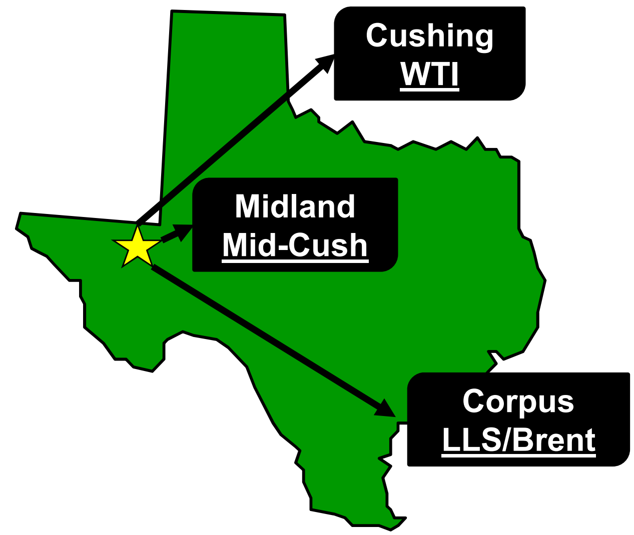
Crude Oil

- EOG Permian Oil Receiving Midland Pricing[1]
  - ≈25% in 2018
  - ≈20% in 2019
- ≈20% of EOG Permian Oil Sold at Premium Gulf Coast Pricing
- Delaware Basin Gathering Terminal Delivers $50MM+ Annual Transportation Savings

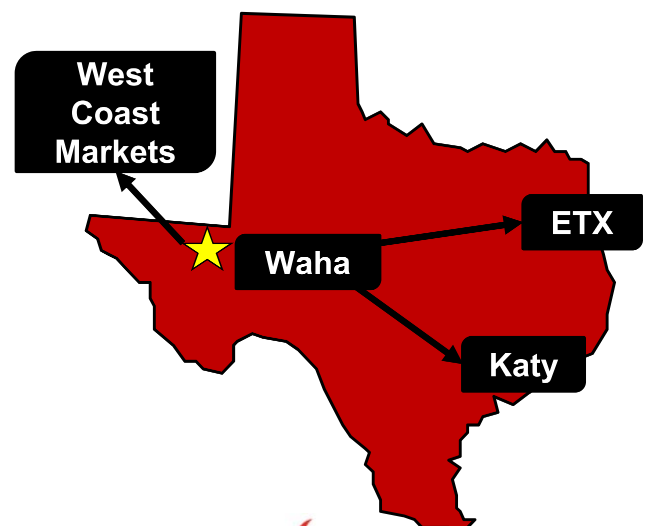
Natural Gas & NGLs

- < 20% of EOG Permian Gas Receiving Permian Pricing in 2018 & 2019
- 90%+ of EOG Permian Gas Covered with Processing Capacity in 2018 & 2019

EOG Permian Crude Oil



EOG Permian Natural Gas



(1) Excludes the benefit of Mid-Cush basis hedges.

Delivering Double-Digit ROCE in 2018

- **Premium Strategy is Permanent**
  - All Investments Tested at $40 Oil and $2.50 Natural Gas
  - Premium Wells Generate >100% Direct ATROR[1] at $60 Oil
  - Replace Premium Inventory 2x Faster Than Drilling

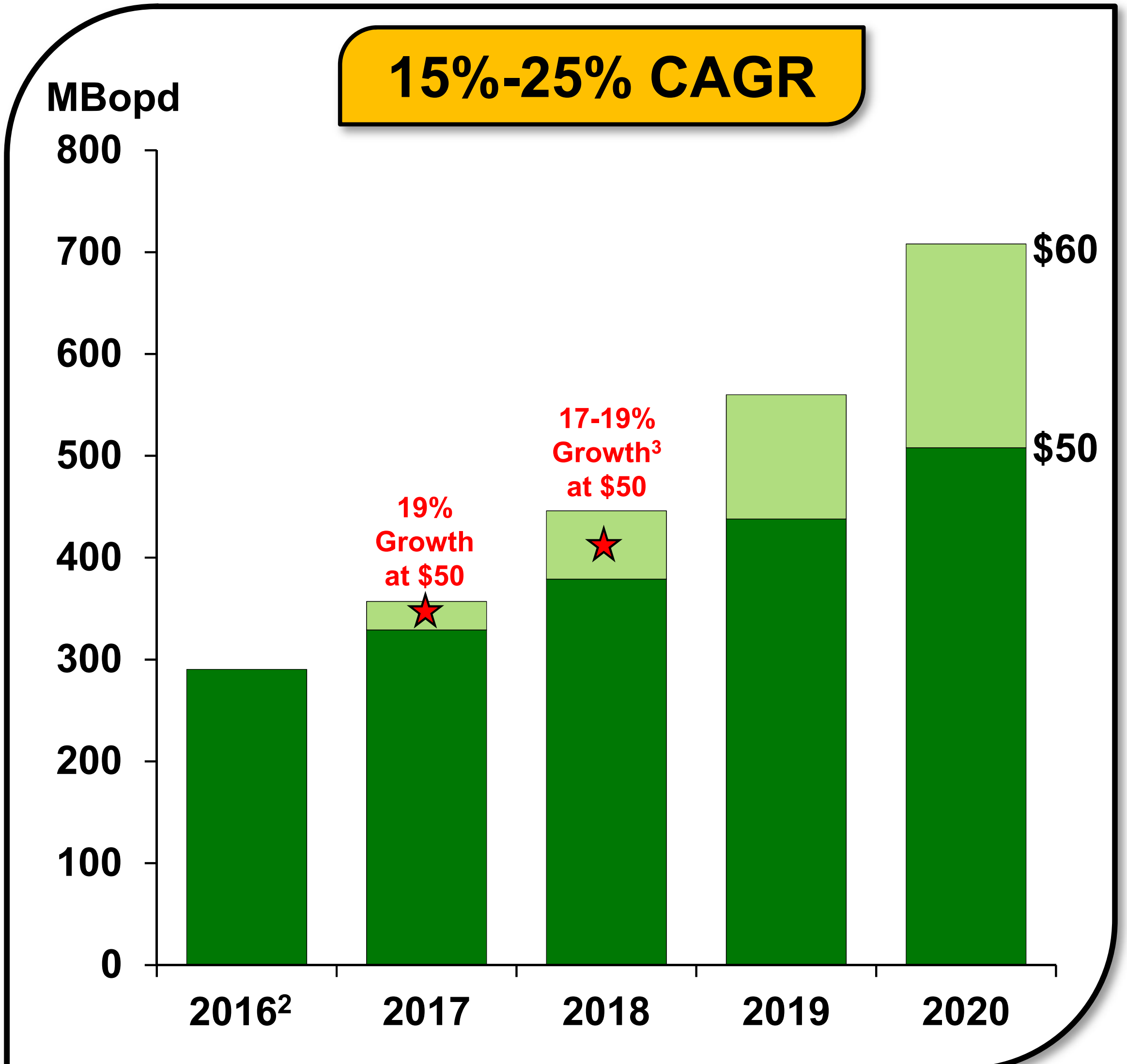
- **Target 17-19% Oil Growth[2]**
  - Complete 700 Net Wells
  - Average 40 Rigs and 19 Completion Spreads

- **Reduce Costs Further**
  - Remain Disciplined in Purchasing Services and Supplies
  - Reduce Well Costs[3] 5%
  - Lower Cash Operating Expenses[2] 6%

- **Generate Positive Free Cash Flow[4] at $50 Oil**
  - Over $1.5 Billion of Free Cash Flow[4] at $60 Oil
  - Target $3 Billion Total Debt[5] Reduction Over Next Four Years
  - Dividend Growth of 31%[6] Above Historical 19% CAGR

(1) See reconciliation schedules.
(2) Based on 2018 guidance, as of August 2, 2018. Cash Operating Expenses include LOE, Transportation and G&A. See slide 18 also.
(3) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.
(4) Discretionary Cash Flow less CAPEX and Dividend. Based on midpoint of 2018 guidance, as of August 2, 2018. See reconciliation schedules for reconciliations and definitions of non-GAAP measures.
(5) Current and long-term debt.
(6) Indicated annual rate, as of August 2, 2018.

Outperforming 2016 – 2020 Outlook
Oil Growth Within Cash Flow[1] at $50 - $60 Oil



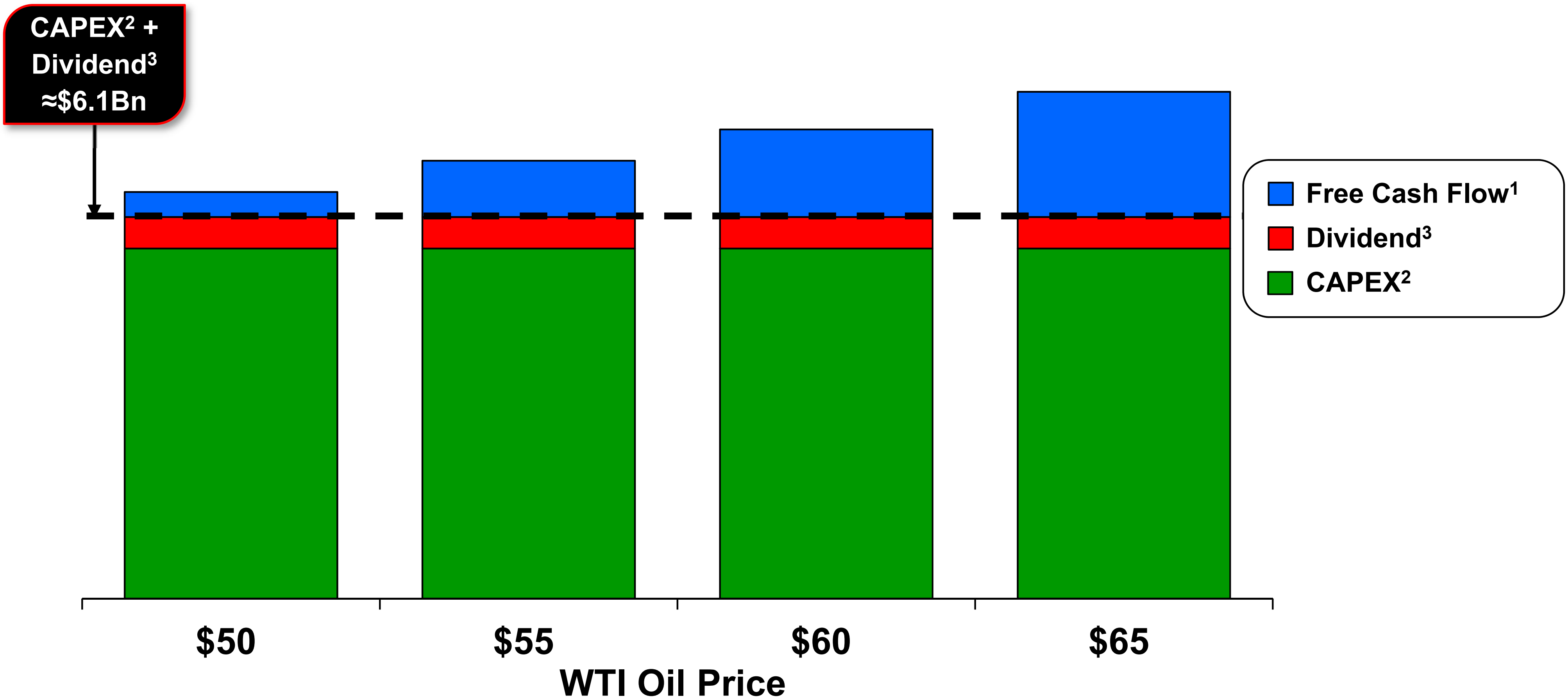
Disciplined Growth

- Growth Remains a Result of Return-Focused Capital Allocation
- Priority on Sustainable Improvement of Cost Structure and Well Productivity
- Ensure That Pace of Development Does Not Exceed Learning Curve

(1) Discretionary Cash Flow ≥ Capex + Current Dividend. See reconciliation schedules for reconciliations and definitions of non-GAAP measures.
(2) Pro forma for full year of production from Yates in 2016.
(3) Based on 2018 guidance, as of August 2, 2018.

Substantial 2018 Free Cash Flow with Higher Oil Prices

Generate Over $1.5 Billion of Free Cash Flow[1] at $60 Oil



(1) Discretionary Cash Flow less CAPEX and Dividend. Based on midpoint of 2018 guidance, as of August 2, 2018. See reconciliation schedules for reconciliations and definitions of non-GAAP measures.
(2) Based on midpoint of 2018 guidance, as of August 2, 2018.
(3) Annualized dividend as of August 2, 2018.

Real-Time Data-Driven Analysis

Data Collection → **Data Management** → **Data Science** → **Data Delivery**

Data Collection

Real-Time

Frac Fleets   Rigs

Producing Wells

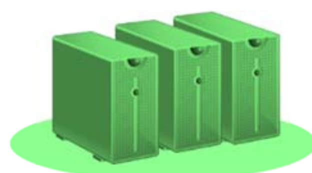
Episodic

- **Logs**
- **Cores**
- **3D Seismic**
- **Micro Seismic**
- **Reservoir Models**

Data Management

Proprietary
Data Marts

↑ ↓



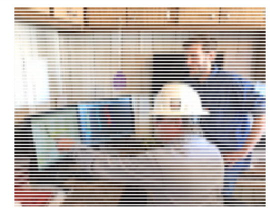
Optimized
for **Big Data**
Processing

Data Science

- **Scalable**
- **Integrated Models**
- **Predictive Analytics**
- **Proprietary Algorithms**

Data Delivery

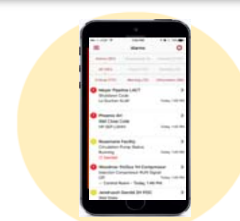
65+ Proprietary Applications



Decentralized Decision Making

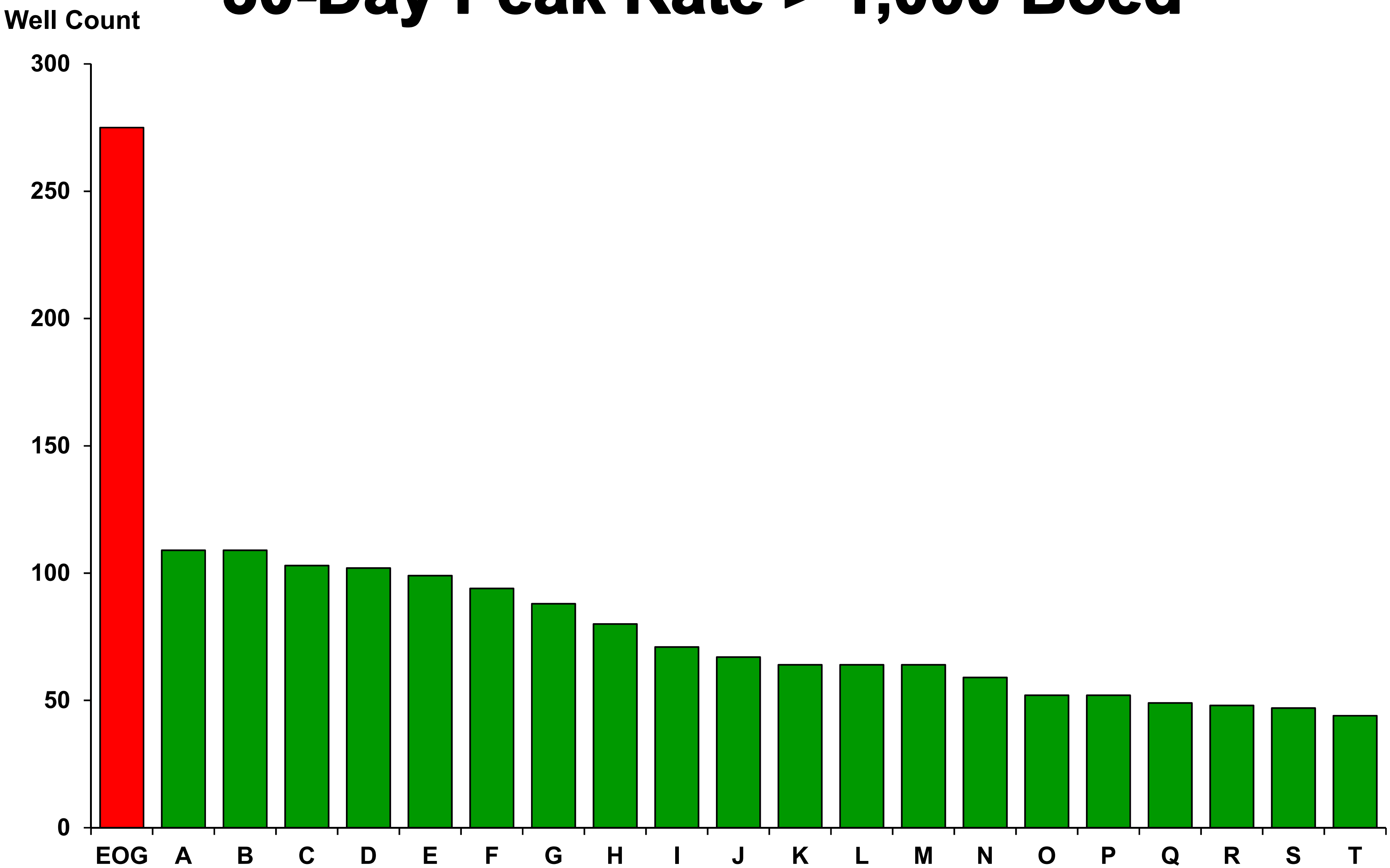
Desktop

"Control Room in Your Pocket"



Mobile

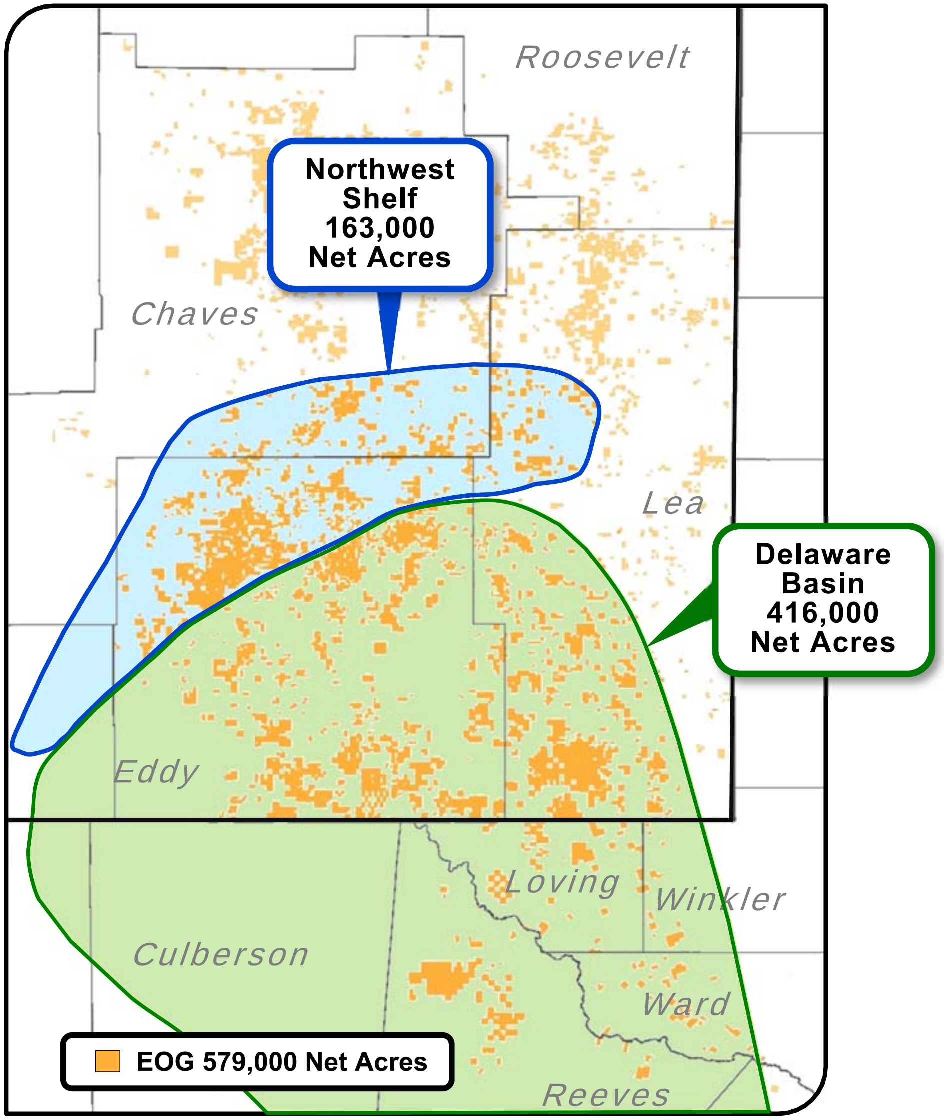
EOG Leads 2017 "Thousand Club"
30-Day Peak Rate > 1,000 Boed



Source: Sanford C. Bernstein & Co. Thousand Club includes wells with peak 30-day production over 1,000 Boed.
Represents 4,000 out of 21,800 wells with initial production in 2017.
Companies: AR, CHK, CLR, COG, COP, CXO, DVN, ECA, FANG, MRO, PE, PXD, RRC, SM, SWN, TOU, VII, WLL, XEC and XOM.

Delaware Basin

- **Net Resource Potential 6.5 BnBoe[1]**
  - **4,800' of Stacked Potential**
  - **6,885 Net Locations; ≈7,200' Laterals**
  - **Average 90% Working Interest and 72% Net Revenue Interest**
- **Average 19 Rigs and 7 Completion Spreads Operating in 2018**
- **2018 Net Well Completions**
  - **≈230 in the Delaware Basin**
  - **≈10 in the Northwest Shelf**
- **Average 46° API Oil**
- **Significant Infrastructure Installed**
  - **Water Sourcing, Gathering and Recycling**
  - **Sand Railcar Unloading Facilities**
  - **Oil and Gas Gathering and Takeaway**
- **Traded 15,000 Net Acres in 2017**
  - **Added 100 Net Wells**
- **Low LOE Per-Unit Rate**

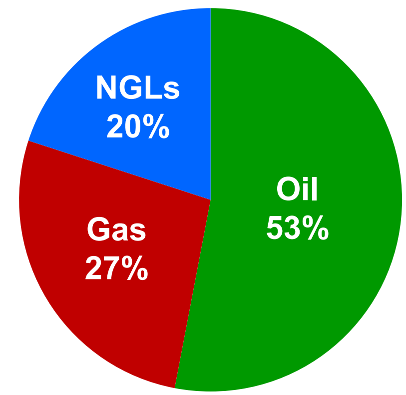


(1) Estimated potential reserves net to EOG, not proved reserves. Includes 739 MMBoe of proved reserves booked at December 31, 2017 and prior production from existing wells.

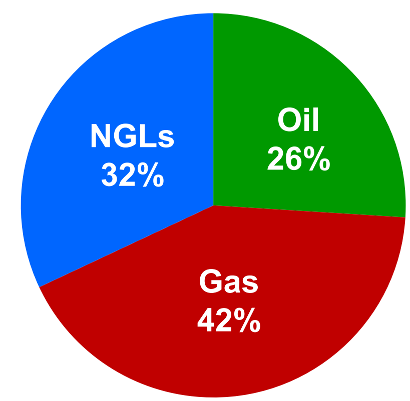
Delaware Basin Wolfcamp

- **346,000 Net Acres Prospective with Multiple Target Zones**
  - 2,660 Net Wells
  - Complete ≈ 190 Net Wells in 2018 vs. 116 in 2017
- **Estimated Resource Potential 2.9 BnBoe[1], Net to EOG**
- **Oil Play**
  - 226,000 Net Acres, 1,585 Net Wells; 660' Spacing
  - Upper and Middle Zones
  - EUR 1,330 MBoe, Gross; 1,050 MBoe, NAR
  - Well Cost[2] Target $7.4MM for 7,000' Lateral
- **Combo Play**
  - 120,000 Net Acres, 1,075 Net Wells; 880' Spacing
  - Upper and Middle Zones
  - EUR 1,550 MBoe, Gross; 1,200 MBoe, NAR
  - Well Cost[2] Target $7.5MM for 8,300' Lateral
- **Testing 500' Spacing and Additional Targets**
- **Wolfcamp Oil and Combo Plays**

	Bopd	Boed	Lateral
- 2Q 2018 62 Gross Wells 30-Day IP	1,255	1,960	6,400'
- Quanah Parker 8-11H	1,535	2,565	9,900'
- Convoy 28 State Com 701H-704H, 601H-602H	2,480	3,515	9,500'



Typical EOG Wolfcamp Oil Well EUR



Typical EOG Wolfcamp Combo Well EUR

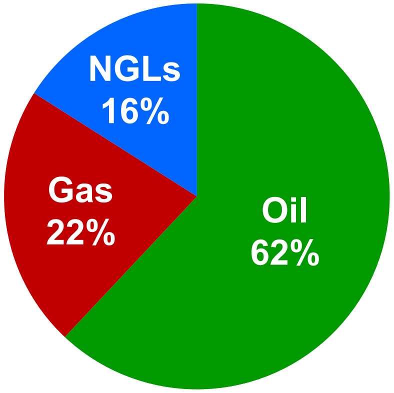
(1) Estimated potential reserves net to EOG, not proved reserves. Includes 509 MMBoe of proved reserves booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback

Delaware Basin Bone Spring

Second Bone Spring

- 289,000 Net Acres Prospective in Northern Delaware Basin
  - 1,870 Net Wells; ≈ 850' Spacing
  - Complete ≈20 Net Wells in 2018 vs. 26 in 2017
- Estimated Resource Potential 1.4 BnBoe[1], Net to EOG
- Typical Well
  - EUR 950 MBoe, Gross; 780 MBoe, NAR
  - Well Cost[2] Target $7.3MM for 7,000' Lateral

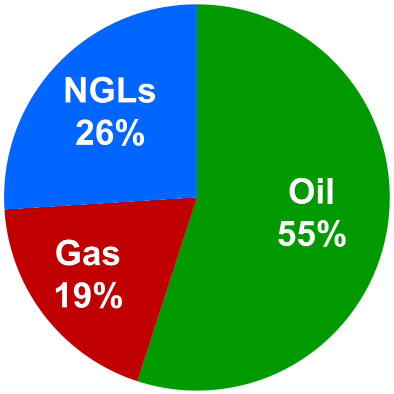
	Bopd	Boed	Lateral
- Bandit 29 State Com 501H-503H, 504Y	2,035	2,410	7,100'



Typical EOG Second Bone Spring Well EUR

First Bone Spring

- 100,000 Net Acres Prospective in Northern Delaware Basin
  - 555 Total Net Premium Locations; ≈ 1000' Spacing
  - Complete ≈ 5 Net Wells in 2018 vs. 9 in 2017
- Estimated Resource Potential 540 MMBoe[1], Net to EOG
- Typical Well
  - EUR 1,185 MBoe, Gross; 975 MBoe, NAR
  - Well Cost[2] Target $7.3MM for 7,000' Lateral

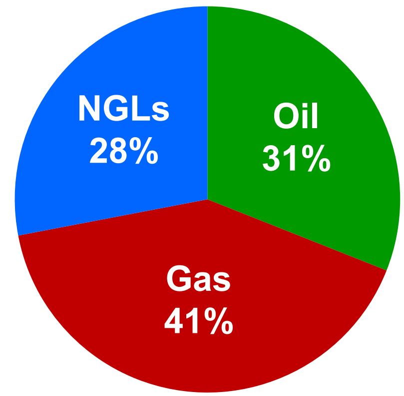


Typical EOG First Bone Spring Well EUR

(1) Estimated potential reserves net to EOG, not proved reserves. Includes 53 MMBoe of proved reserves in the Second Bone Spring and 57 MMBoe in the First Bone Spring booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

Delaware Basin Leonard

- 160,000 Net Acres Prospective
  - 1,800 Net Wells
  - 660' Spacing in A and B Zones
  - Complete ≈15 Net Wells in 2018 vs. 20 in 2017
- Estimated Resource Potential 1.7 BnBoe[1], Net to EOG
- Typical Well
  - EUR 1,175 MBoe, Gross; 940 MBoe, NAR
  - Well Cost[2] Target $6.3MM for 6,800' Lateral



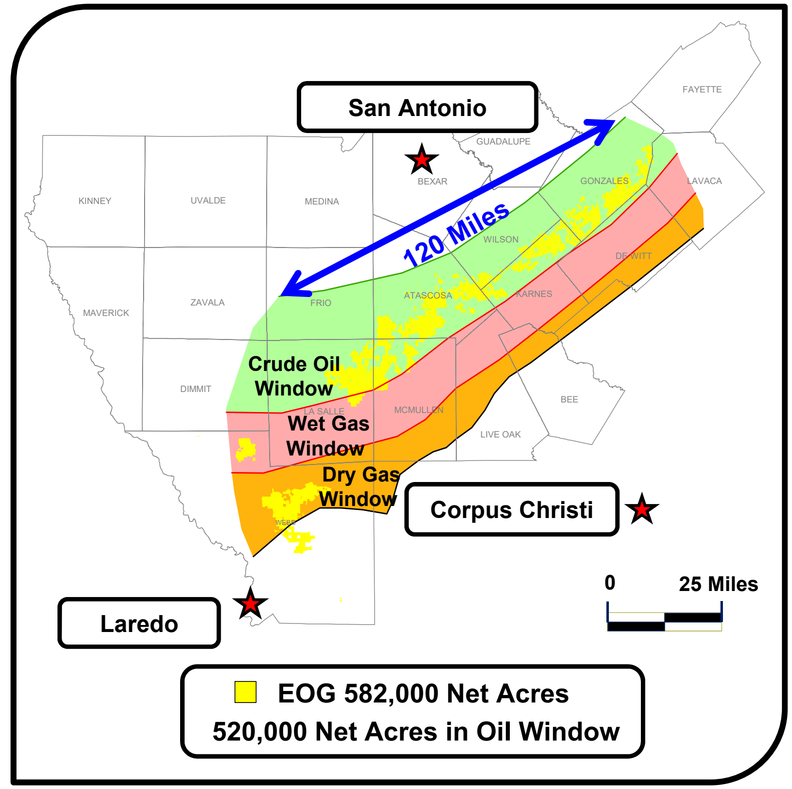
Typical EOG Red Hills Leonard Shale Well EUR

	Bopd	Boed	Lateral
2Q 2018 7 Gross Wells 30-Day IP	965	1,745	4,500'

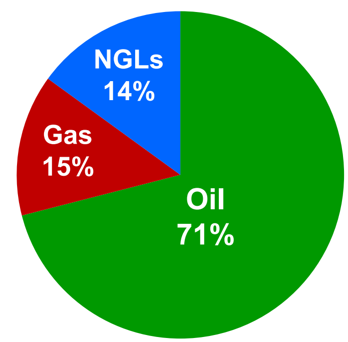
(1) Estimated potential reserves net to EOG, not proved reserves. Includes 100 MMBoe proved reserves in the Leonard Shale booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

South Texas Eagle Ford Oil

- **Largest Oil Producer and Acreage Holder in the Eagle Ford**
  - **Average 11 Rigs and 7 Completion Spreads in 2018**
  - **Complete ≈270 Net Wells in 2018 vs. 217 in 2017**
- **Estimated Resource Potential 3.2 BnBoe[1]; 7,200 Net Wells**
  - **Average 96% Working Interest and 74% Net Revenue Interest**
- **Typical Well**
  - **5,300' Lateral; ≈40-Acre Spacing**
  - **EUR 580 MBoe, Gross; 450 MBoe, NAR**
  - **Well Cost[2] Target $4.3MM**
- **Precision Targeting**
  - **Lateral Drilling Window 20' vs. Prior 150'**
- **Implementing Enhanced Oil Recovery Program**
  - **Incremental Reserves 30%-70%**
  - **Direct ATROR[3] >30% and PVI[4] >2.0**
  - **Convert 90 Wells to EOR in 2018 vs. 56 in 2017**



	Bopd	Boed	Lateral
2Q 2018 74 Gross Wells 30-Day IP	1,530	1,920	7,200'
- Sandies Creek A-F 1H-6H	2,320	3,205	6,500'
- Hickok 5H-8H	2,020	2,685	5,000'
- Antrim Cook Unit 15H-18H	2,210	2,240	11,200'

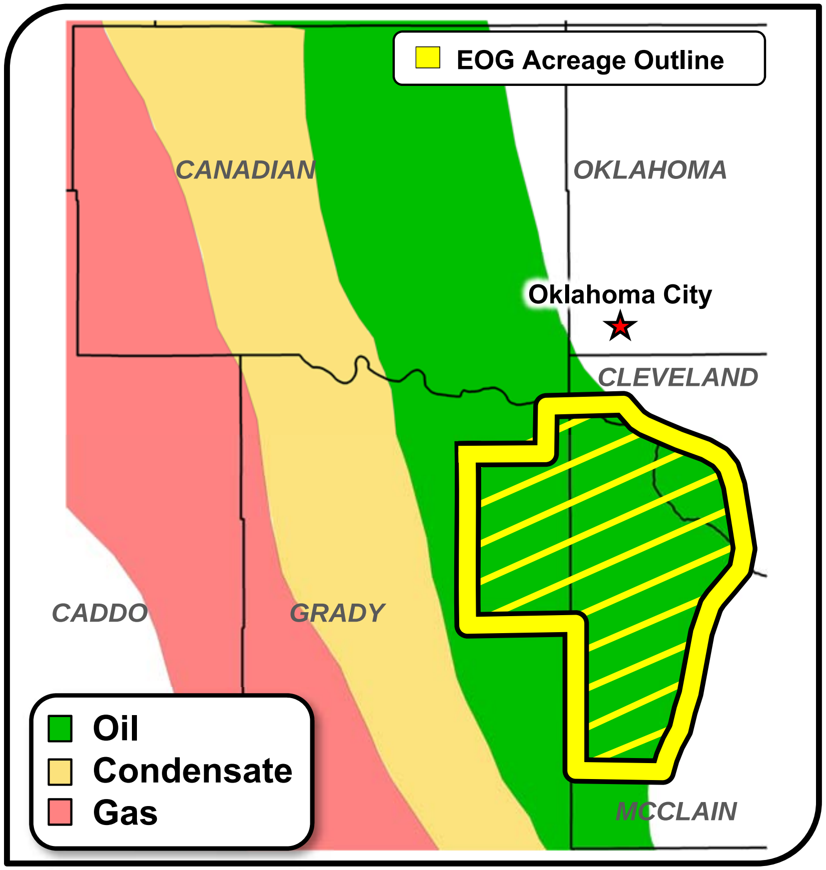


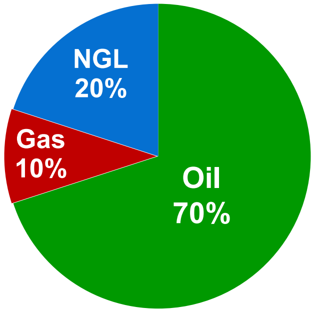
Typical EOG Eagle Ford Well EUR

(1) Estimated potential reserves net to EOG, not proved reserves. Includes 1,026 MMBoe proved reserves booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback
(3) See reconciliation schedules. Assumes oil price $40 per barrel WTI and natural gas price $2.50 per MMBtu Henry Hub.
(4) Net present value divided by capital investment.

Eastern Anadarko Basin Woodford Oil Window

- **High-Return Premium Play in Crude Oil Window**
  - **Average 2 Rigs and 1 Completion Spread in 2018**
  - **Complete ≈25 Net Wells in 2018**
- **50,000 Net Acres Prospective**
  - **Accumulated for ≈$750 per Acre**
  - **260 Net Wells; 660' Spacing**
- **Estimated Resource Potential 210 MMBoe[1]**
- **Typical Well**
  - **EUR 1,000 MBoe, Gross; 800 MBoe, NAR**
  - **Well Cost[2] Target $7.8 MM for 9,500' Lateral**





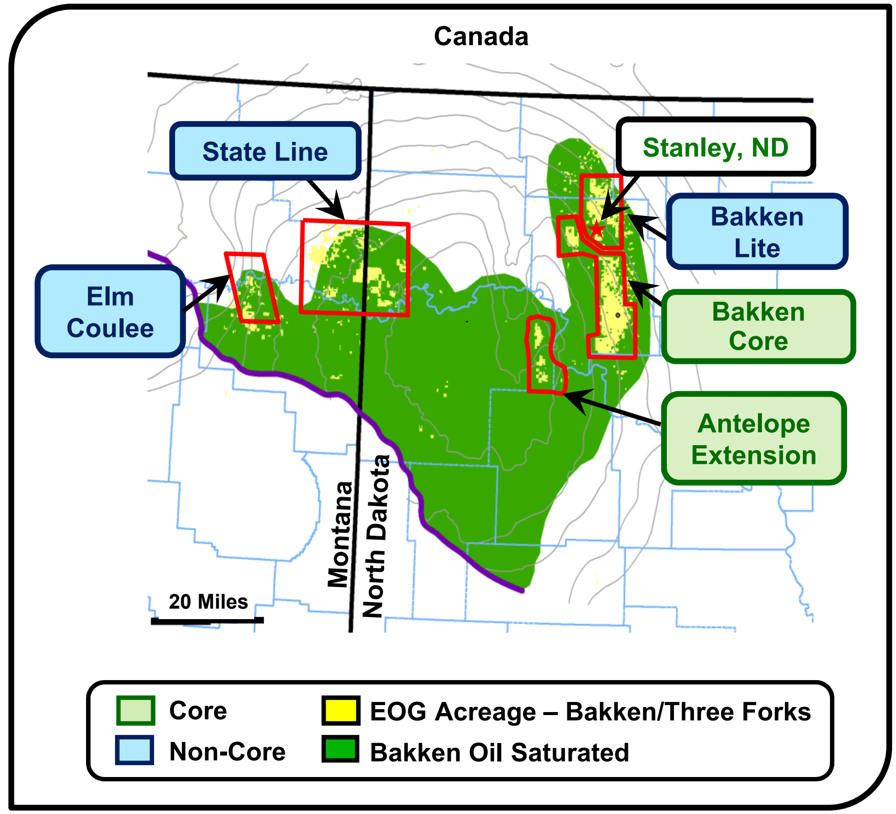
Typical EOG Woodford Oil Well EUR

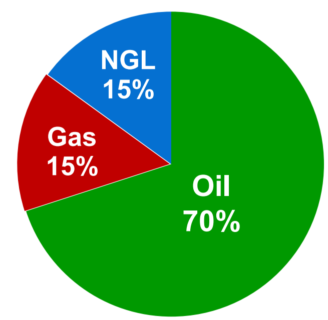
(1) Estimated potential reserves net to EOG, not proved reserves. Includes 1.6 MMBoe proved reserves in the Woodford booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

Bakken/Three Forks

- **High-Return Drilling Activity Since 2006**
  - Average 1 Rig Operating in 2018
  - Complete ≈20 Net Wells in 2018 vs. 35 in 2017
- **Estimated Resource Potential 1.0 BnBoe[1]**
  - Well Cost[2] Target $4.6 MM for 8,400' Lateral
  - 650' Spacing
  - Average 70% Working Interest and 59% Net Revenue Interest
- **Lower Costs with Seasonal Development**
  - Complete Wells & Build Facilities During Warmer Months
- **Focus on Premium Locations**
  - Bakken Core and Antelope Extension Areas
  - 120,000 Net Acres
- **2Q 2018 30-Day IP**

	Bopd	Boed	Lateral
- Clarks Creek 108, 155 – 0706H	2,240	2,980	9,200'



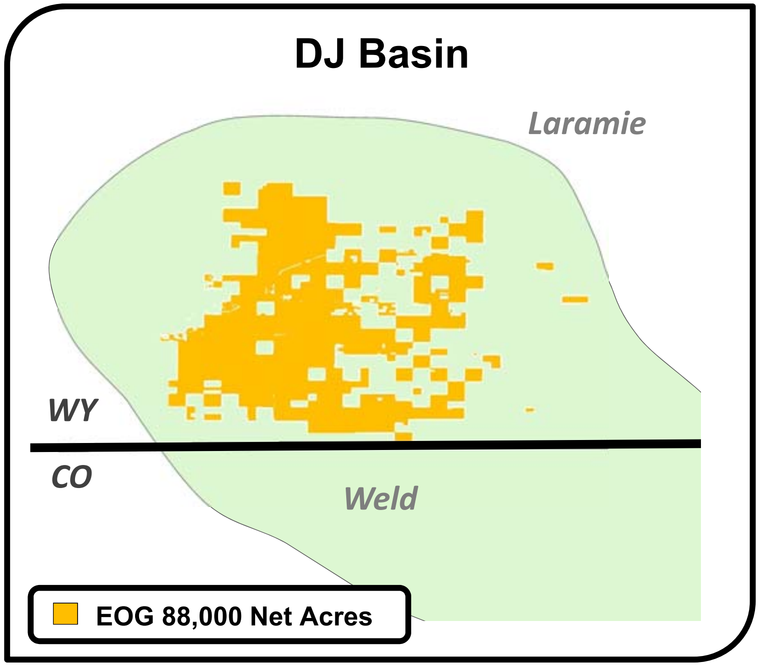


Typical Williston Basin Remaining Wells EUR

(1) Estimated potential reserves net to EOG, not proved reserves. Includes 207 MMBoe proved reserves in the Bakken/Three Forks booked at December 31, 2017 and prior production from existing wells.
(2) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

DJ Basin

- **Codell Identified as Premium Play**
- **Average 2 Rigs and 1 Completion Spread in 2018**
- **Complete ≈35 Net Wells in 2018 vs. 17 in 2017**
- **Well Cost[1] Target $4.0MM for 9,000' Lateral**



	Bopd	Boed	Lateral
2Q 2018 8 Gross Wells 30-Day IP			
- Windy 576, 577-1702H	675	765	9,300'
591, 593-1705H	755	870	9,300'

(1) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.

Trinidad

- **Focused on Exploration in 2018**
  - **Acquire Additional State-of-the-Art Seismic**
  - **Identify High-Quality Shallow-Water Prospects**

- **Banyan & Osprey**
  - **Completed 5 Net Wells in 2017**
  - **Initial Rates Greater Than 30 MMcfd**

- **Sercan Joint Development Project**
  - **Completed 5 Gross / 3 Net Well Program in 2017**

- **Entered Into New Gas Supply Contract**
  - **Enables Additional Drilling**
  - **Sold into Trinidad Domestic Gas Market**

Cautionary Notice Regarding Forward-Looking Statements: This presentation includes 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. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production, costs and asset sales, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target,", "aims," "goal," "may," "will," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, reduce or otherwise control operating and capital costs, generate income or cash flows, pay down indebtedness or pay and/or increase dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Furthermore, EOG has presented or referenced herein or in its accompanying disclosures certain forward-looking, non-GAAP financial measures, such as free cash flow and discretionary cash flow, and certain related estimates regarding future performance, results and financial position. These forward-looking measures and estimates are intended to be illustrative only and are not intended to reflect the results that EOG will necessarily achieve for the period(s) presented. EOG's actual results may differ materially from the measures and estimates presented or referenced herein. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- *the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;*
- *the extent to which EOG is successful in its efforts to acquire or discover additional reserves;*
- *the extent to which EOG is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;*
- *the extent to which EOG is successful in its efforts to market its crude oil and condensate, natural gas liquids, natural gas and related commodity production;*
- *the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, transportation and refining facilities;*
- *the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;*
- *the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;*
- *EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;*
- *the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;*
- *competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties, employees and other personnel, facilities, equipment, materials and services;*
- *the availability and cost of employees and other personnel, facilities, equipment, materials (such as water) and services;*
- *the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;*
- *weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression and transportation facilities;*
- *the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;*
- *EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;*
- *the extent to which EOG is successful in its completion of planned asset dispositions;*
- *the extent and effect of any hedging activities engaged in by EOG;*
- *the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;*
- *political conditions and developments around the world (such as political instability and armed conflict), including in the areas in which EOG operates;*
- *the use of competing energy sources and the development of alternative energy sources;*
- *the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;*
- *acts of war and terrorism and responses to these acts;*
- *physical, electronic and cyber security breaches; and*
- *the other factors described under ITEM 1A, Risk Factors, on pages 14 through 23 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.*

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the duration and extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

Oil and Gas Reserves; Non-GAAP Financial Measures: The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve estimates provided in this presentation that are not specifically designated as being estimates of proved reserves may include "potential" reserves and/or other estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.