Investor Presentation

July 2018

Disclaimer

The information in this presentation includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, maintenance capital requirements, expected production and costs, reserves, hedging activities, capital investments and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect our results of operations and financial position appear in Risk Factors in our final prospectus dated July 25, 2018 as filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on July 27, 2018 (the "prospectus").

Factors (but not necessarily all the factors) that could cause results to differ include among others:

* volatility of oil, natural gas and NGL prices;
* inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and meet working capital requirements;
* price and availability of natural gas;
* our ability to use derivative instruments to manage commodity price risk;
* impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
* uncertainties associated with estimating proved reserves and related future cash flows;
* our inability to replace our reserves through exploration and development activities;
* our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
* effects of competition;
* our ability to make acquisitions and successfully integrate any acquired businesses;
* market fluctuations in electricity prices and the cost of steam;
* asset impairments from commodity price declines;
* large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
* geographical concentration of our operations;
* our ability to improve our financial results and profitability following our emergence from bankruptcy and other risks and uncertainties related to our emergence from bankruptcy;
* changes in tax laws;
*impact of derivatives legislation affecting our ability to hedge;
* ineffectiveness of internal controls;
* concerns about climate change and other air quality issues;
*catastrophic events;
*litigation;
* our ability to retain key members of our senior management and key technical employees;
* information technology failures or cyber attacks:

We undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

This presentation has been prepared by Berry and includes market data and other statistical information from sources believed by it to be reliable, including independent industry publications, government publications or other published independent sources. Some data is also based on Berry's good faith estimates, which are derived from its review of internal sources as well as the independent sources described above. Although Berry believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy and completeness.

Proved reserve data included in this presentation is based on a proved reserves report prepared by DeGoyler and MacNaughton as of December 31, 2017 and its addendum dated June 28, 2018. Unless otherwise noted or suggested by context, reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting. Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact Berry's strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered. Estimated Ultimate Recovery, or "EUR," refers to estimates of the sum of reserves remaining as of a given date and cumulative production as of that date from a currently producing or hypothetical future well, as applicable. These quantities do not necessarily constitute or represent reserves as defined by the SEC.

Disclaimer (Cont.)

Berry's estimated net proved Strip Pricing reserves were prepared on the same basis as Berry's SEC reserves, except for the use of pricing based on closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX Henry Hub for natural gas on May 31, 2018. Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. The volume-weighted average prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL and $1.943 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining Berry's Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. Berry believes that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. For a comparison of Strip Pricing to SEC Pricing, please see slides 48-49.

Berry uses PV-10, a supplemental financial measure that is not presented in accordance with U.S. generally accepted accounting principles ("GAAP"), in this presentation, which reflects the present value of its estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization expense, exploration expenses and hedging activities, discounted at 10% per year before income taxes. GAAP does not prescribe any corresponding measure for PV-10 of reserves as of an interim date or on any basis other than SEC prices. As a result, it is not practical for us to reconcile PV-10 using Strip Pricing as of May 31, 2018 to GAAP standardized measure.

Berry uses Adjusted EBITDA (on a hedged basis), a financial measure that is not presented in accordance with GAAP, in this presentation. Adjusted EBITDA is used as a supplemental non-GAAP financial measure by Berry's management and by external users of Berry's financial statements, such as industry analysts, investors, lenders and rating agencies. Berry believes Adjusted EBITDA is useful because it allows management to more effectively evaluate Berry's operating performance and compare the results of its operations period to period without regard to Berry's financing methods or capital structure. In addition, Berry's management uses Adjusted EBITDA to evaluate cash flow available to fund operations.

Berry defines Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, amortization and accretion; exploration expense; derivative gains or losses, net of cash received or paid for scheduled derivative settlements, impairments, stock compensation expense and other unusual out-of-period and infrequent items, including restructuring and reorganization costs. Berry excludes the foregoing items from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. In addition, Adjusted EBITDA Unhedged excludes cash received or paid for scheduled derivative settlements. Certain items excluded from Adjusted EBITDA and Adjusted EBITDA Unhedged are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as historic costs of depreciable assets, none of which are components of Adjusted EBITDA or Adjusted EBITDA Unhedged. Adjusted EBITDA and Adjusted EBITDA Unhedged are not measures of net income (loss) as determined by GAAP and should not be considered an alternative to net income (loss), oil, natural gas and NGL revenues or any other measure of financial performance or liquidity presented in accordance with GAAP. You should not consider Adjusted EBITDA or Adjusted EBITDA Unhedged in isolation or as a substitute for an analysis of Berry's results as reported under GAAP. Because Adjusted EBITDA or Adjusted EBITDA Unhedged may be defined differently by other companies in Berry's industry, Berry's computations of Adjusted EBITDA or Adjusted EBITDA Unhedged may not be comparable to other similarly titled measures of other companies, thereby diminishing its utility. Please see slide 45 for a reconciliation of Adjusted EBITDA and Adjusted EBITDA Unhedged to net income (loss).

Berry uses Adjusted EBITDA less Capital Expenditures, a supplemental financial measure that is not presented in accordance with GAAP. Berry defines Adjusted EBITDA less Capital Expenditures as Adjusted EBITDA less Capital Expenditures. Adjusted EBITDA less Capital Expenditures is used by management as a measure of cash generated by the business, after accounting for Capital Expenditures, available for investment, dividends, debt reduction or other purposes. Please see slide 46 for a reconciliation of Adjusted EBITDA and Adjusted EBITDA less Capital Expenditures to net cash provided (used) by operating activities.

Berry uses Adjusted General and Administrative Expenses ("Adjusted G&A Expenses"), a supplemental financial measure that is not presented in accordance with GAAP, in this presentation. We define Adjusted G&A Expenses as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. Management believes Adjusted G&A Expenses is useful because it allows management to more effectively compare our performance from period to period. We exclude the items listed above from general and administrative expenses in arriving at Adjusted G&A Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Adjusted G&A Expenses should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Our computations of Adjusted G&A Expenses may not be comparable to other similarly titled measures of other companies. Please see slide 47 for a reconciliation of Adjusted G&A Expenses to general and administrative expenses.

The type curves provided in this presentation are prepared by Berry's internal reserve engineers by conducting a decline curve analysis of production results from Berry's wells to generate an arithmetic mean of historical production for each project. Berry relied on the production results through February 1, 2018 for its own wells that it submitted to the Division of Oil, Gas, and Geothermal Resources of the California Department of Conservation ("DOGGR"), which results are publicly available at maps.conservation.ca.gov/doggr/wellfinder/#openModal, to generate the type curves, and these wells are listed on slides 42-44 of this presentation. These type curves were not relied upon by DeGoyler and MacNaughton in preparing its reserves report dated as of December 31, 2017 or the addendum to that report dated as of June 28, 2018, and DeGoyler and MacNaughton has not reviewed the type curves included in this presentation. Investors are cautioned not to place undue reliance on Berry's type curves presented herein, and Berry's actual production results and ultimate recoveries may to differ substantially.

Today's Presenters

	Summary Backgrounds
Trem Smith ***Chief Executive Officer***	■ CEO of Berry Petroleum since March 2017 (previously named Interim CEO in January 2017) ■ Former CEO of Hillwood International Energy ■ 25 years at Chevron; numerous international and US-based management positions ■ Graduated magna cum laude from Amherst College with a degree in Geology ■ Masters and PhD in Economic Geology from Pennsylvania State University
Cary Baetz ***Executive Vice President & Chief Financial Officer***	■ CFO of Berry Petroleum since May 2017 ■ Former CFO of Seventy Seven Energy ■ Former CFO of Atrium Companies ■ Former CFO of Boots & Coots International Well Control ■ B.S. in Finance / Accounting from Oklahoma State University, MBA from University of Arkansas
Gary Grove ***Executive Vice President & Chief Operating Officer***	■ Appointed COO of Berry Petroleum in May 2017 ■ Former COO of Bonanza Creek Energy; part of executive team that took Bonanza Creek public ■ Held various reservoir engineering and management positions with UNOCAL and Nuevo Energy ■ B.S. in Petroleum Engineering from Marietta College

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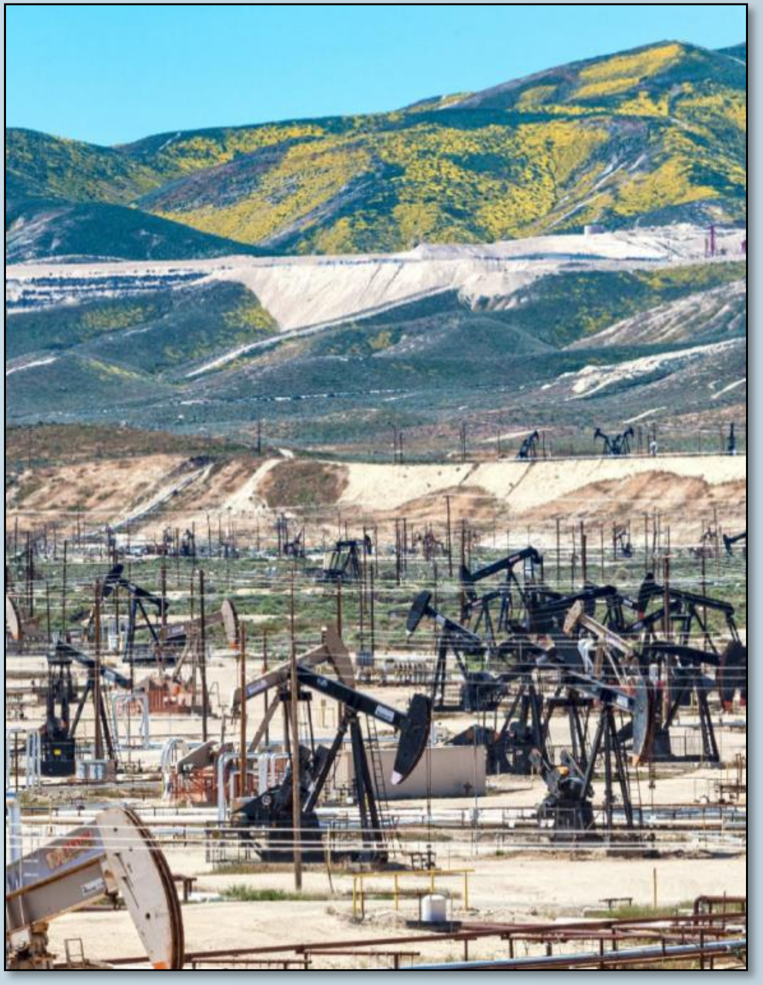


Ethel D lease, Berry's first oil prospect in 1909

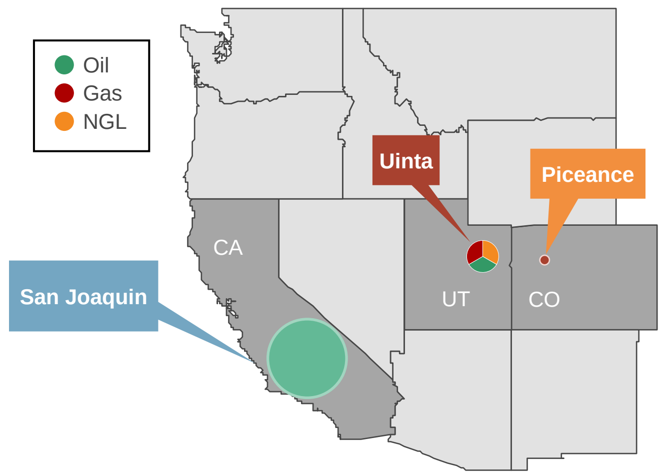
I. Introduction

Sunrise over Berry's Belgian lease in Kern County, CA

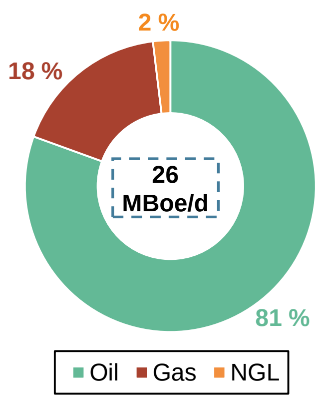
Berry Petroleum: A U.S. Onshore Conventional *Oil* Company

- **Conventional, oil-driven, Western United States focused**
- **Brent-influenced oil pricing dynamics**
- **Long production history and high operational control**
- **Shallow decline curves with predictable production profiles**
- **Extensive inventory of high-return, low risk drilling locations**
- **High average working interest (97%) and net revenue interest (87%)**
- **Proven management team with track record of leading public companies**

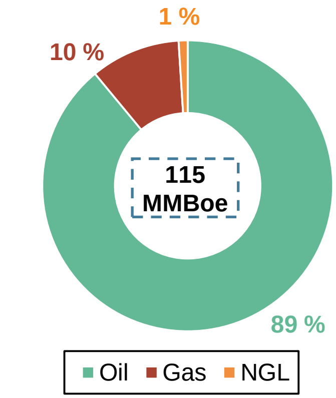
Map of Berry Assets[1,2]



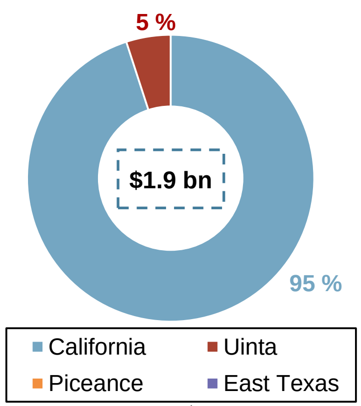
1Q18 Production by Commodity[3]



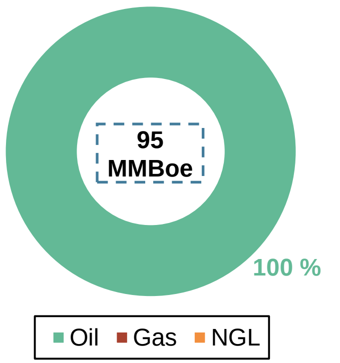
1P Reserves by Commodity[2]



1P PV-10 Value by Area[2,4]



California 1P Reserves by Commodity[2]



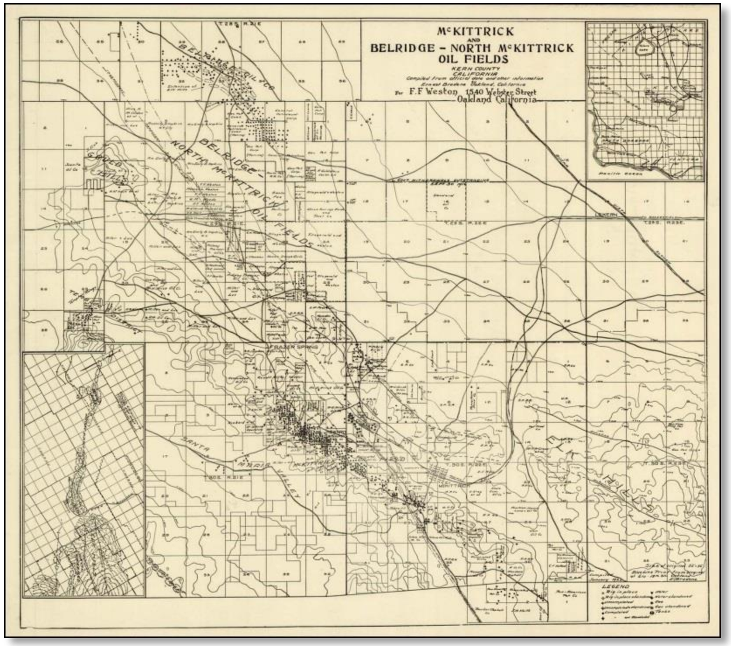
[1] Excludes East Texas Assets and bubble size implies PV-10 value of reserves at Strip Pricing as of May 31, 2018. | [2] Prepared based on 3rd party reserves report addendum as of June 28, 2018 and closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. For a comparison to SEC Pricing, please see slides 48-49. | [3] Data may not add to 100% due to rounding. | [4] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.

California Has a Rich History in Oil

- Native Americans used oil from ground seepages as a lubricant and sealant
- Seeps spurred commercial interest, with original discoveries completed with pick and shovel
- First commercial oil production in 1875 in Pico Canyon Oilfield (Los Angeles Basin)
- Initial refining operations in 1870s

- California is home to world-class, prolific oil basins
  - *Basins[1]:*
    - ★ San Joaquin (**EUR 19 Bboe**)
    - – Los Angeles (**EUR 10 Bboe**)
    - – Ventura-Santa Barbara (**EUR 5 Bboe**)
  - *San Joaquin Basin's top fields[1]:*
    - ★ Midway-Sunset (**EUR 3.6 Bboe**)
    - – Kern River (**EUR 2.6 Bboe**)
    - ★ South Belridge (**EUR 2.2 Bboe**)
    - – Elk Hills (**EUR 1.9 Bboe**)

★ **Berry Operating Areas**



McKittrick and South Belridge Oil Fields Displayed on a Map from 1920

Geologic field party, west side Kern County, 1908

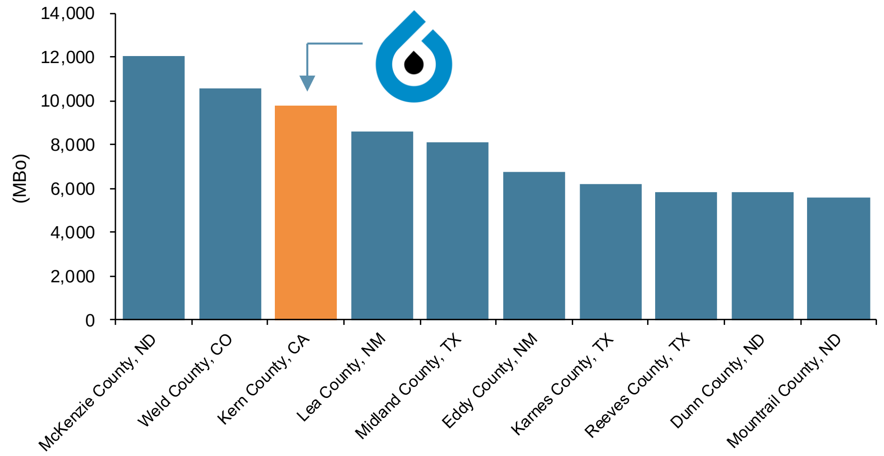
Lakeview Gusher in 1910
More than 9 million barrels over 544 days
-- Midway-Sunset Oil Field in Kern County, California --

[1] 2009 Annual Report of the State Oil & Gas Supervisor, DOGGR.

California is a Major Oil Producing State

- **California was the third largest oil producing state in Lower 48 during 2017[1]**
  - Over $26 billion in annual state and local tax revenue contributed by oil and gas[2]
- **Kern County is the third largest oil producing county in the nation[3]**
  - Oil and gas contributes $14 billon annually to Kern's economy and is responsible for 20% of local GDP[4]
  - The top three and six of the top ten Kern County property taxpayers are E&P companies[5]
  - Kern oil and gas annual wages per employee are almost double that of the average of all other industries[6]
- **Berry's California operations are low intensity and concentrated in rural California**
  - Majority of production is focused on thermal stimulation, distinct from high-intensity fracking in unconventional plays
  - Operates in Kern County, which is away from urban areas as well as sensitive natural areas

Top Crude Oil Producing Counties in Lower 48 (Feb 2018)[3]



California Oil & Gas Supported on Both Sides of the Aisle

"When you talk about American energy, it means more production….. When you have greater production in America, it means more American jobs."
- Kevin McCarthy (R-CA), U.S. House Majority Leader, 4/13/18

"California is only producing 30 percent of its oil, the rest comes in ships….. I don't believe that makes sense."
- Jerry Brown (D-CA), Governor, 5/16/17

[1] EIA 2017 Total Crude Oil Production. | [2] Los Angeles County Economic Development Corporation; YE 2015. | [3] DrillingEdge. | [4] 2017 Kern EDC Economic Impacts. | [5] 2017-2018 Kern County property tax bills mailed by Kern County Treasurer/Tax Collector. | [6] Bureau of Labor Statistics - Kern County Oil and Gas Industry Annual Wages, 2014.

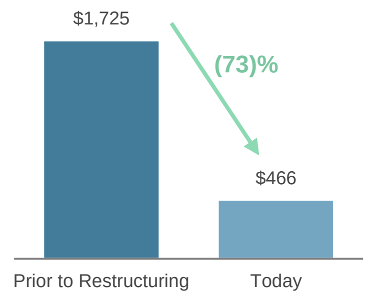
The New Berry Petroleum

Summary of Events

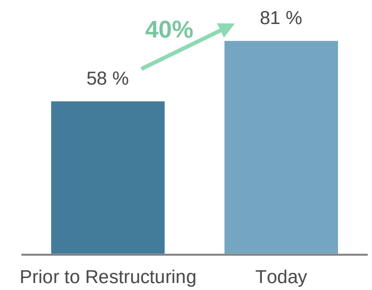
- In December 2013, LINN Energy acquired Berry's predecessor company for $4.6 billion
- On February 28, 2017, Berry emerged as a stand-alone company with new management, board and ownership
  - Restructuring resulted in a $1.3 billion aggregate reduction of outstanding debt
  - Our largest shareholders *contributed $335 million of new capital* in the form of preferred equity, demonstrating financial support and commitment to our long term success
  - Preferred equity will convert to common equity at IPO
- On July 31, 2017, we divested our non-core 78% working interest in the Hugoton natural gas field in Kansas and Oklahoma Panhandle (**70% gas, 30% NGL**)
- Also on July 31, 2017, we purchased the remaining 84% working interest in South Belridge Hill in Kern County, CA (**100% oil**)
- In April 2018, we acquired additional acreage from Chevron in the North Midway-Sunset area in Kern County, CA (**100% oil**)

What Changed Since Our Emergence?

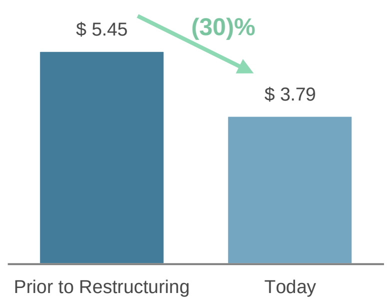
Total Debt[1] ($mm)



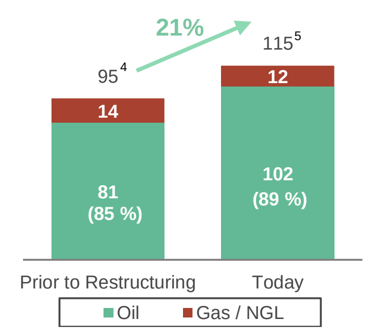
Production Commodity Mix[2] (% Oil)



Adjusted G&A Expenses[3] ($/Boe)



Proved Reserves[4] (MMBoe)



Source: Predecessor public filings

[1] Debt prior to restructuring is calculated as of Q3 2016. Today's debt is as of June 30, 2018. | [2] Commodity mix prior to restructuring refers to FY 2016 production (prior to Hill acquisition / Hugoton disposition) and today's commodity mix refers to Q1 2018 production. | [3] Adjusted G&A Expenses prior to restructuring is for the year ended December 31, 2016. Adjusted G&A Expenses prior to restructuring was generally management charges from Linn. Adjusted G&A Expenses today is for Q1 2018. Adjusted G&A Expenses today excludes non-recurring restructuring and other costs and non-cash stock compensation expense for the three months ended March 31, 2018. For an Adjusted G&A Expenses reconciliation, please see slide 47. | [4] Reserves (December 31, 2016 reserves use SEC Pricing) prior to restructuring represents Berry's proved reserves as of December 31, 2016 pro forma for the Hugoton disposition plus proved reserves associated with the Hill acquisition as of March 31, 2017. | [5] Proved reserves today prepared based on 3rd party reserves report addendum as of June 28, 2018 and closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. For a comparison to SEC Pricing, please see slides 48-49.

We Are Broadly Advantaged vs. Unconventional Resource Players

	Berry	Resource / Shale Players	*The Berry Benefit*
Production History	Decades of History	Still Learning	✓
Production Declines	Low	High	✓
IP Rates	Lower	Higher	✗
Capital and Service Cost Intensity	Low	High (i.e. "Big fracs")	✓
Operating Cost Stability/ Predictability	Stable	Experiencing Inflation	✓
Potential Gas/Oil Ratio (GOR) Issues	No (CA ~100% oil)	Yes	✓
Takeaway and Service Capacity Constraints	No (We service CA demand)	Yes (High basis differentials in some regions)	✓
Ability to Generate and Return Capital for Shareholders	Yes	Recurring returns of capital uncommon historically and today	✓

We Have Significant Financial Flexibility Across Oil Price Scenarios

Our capital allocation priorities are flexible and focused on delivering value to shareholders across cycles

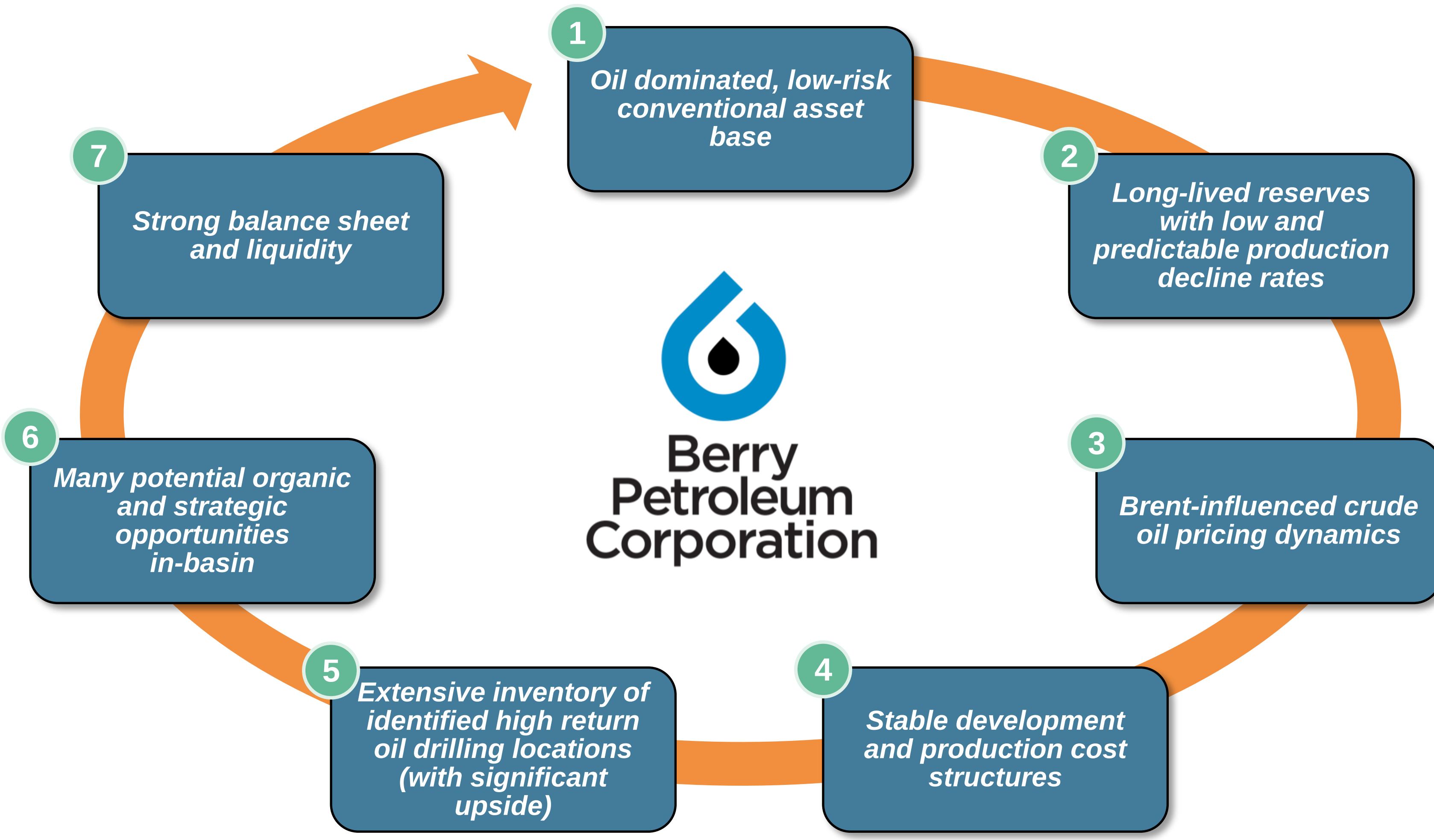
	Currently Planned Capital Allocation / Results
> $60 / Bbl Brent Price	■ Accelerate development program ■ Pursue accretive acquisition opportunities ■ Grow dividend / repurchase shares ■ Prepay debt obligations
~$60 / Bbl Brent Price	■ Fund planned development / growth program ■ Pay current dividend ■ Generate positive free cash flow post-dividend
~$50 / Bbl Brent Price	■ Sustain / grow production ■ Pay current dividend ■ Achieve levered free cash flow neutrality post-dividend

We estimate ~$110mm in annual capital to keep production volumes flat over the next three years

II. Key Investment Highlights

Berry's Poso Creek field, California

Our Key Asset, Operational and Financial Advantages



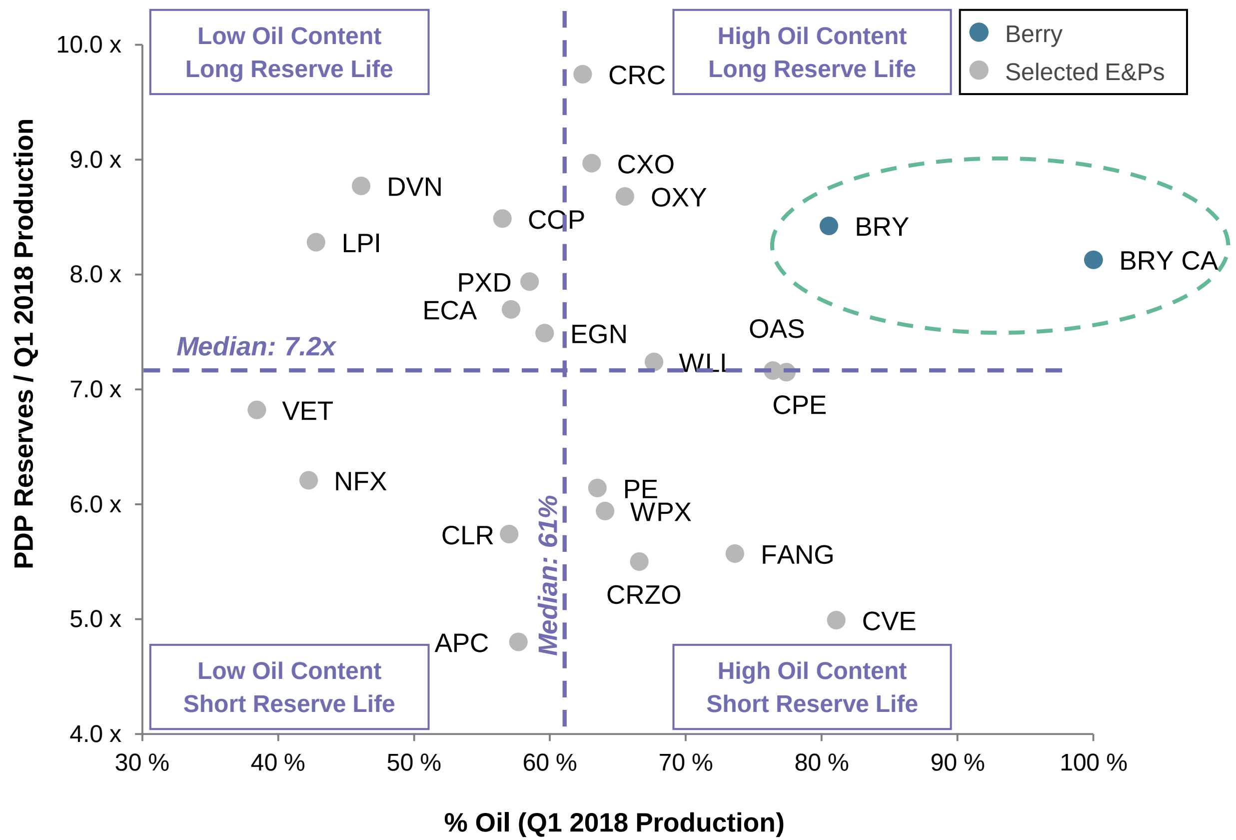
Our Low Risk, Oily Reserve Base Has a Long Reserve Life

Berry is highly differentiated relative to other oil-focused E&Ps through its unique combination of high oil content production and long lived reserves

What Makes Our Assets Low Risk

- Decades of production data
  - *We have seen full well life*
- Well-known geology
- Proven D&C technology
- No GOR issues in California
- Low and predictable declining production base
- Low-cost, easy-to-drill wells provide flexibility and mitigate service cost inflation (low intensity)

% Oil (Q1 2018 Production) vs. PDP Reserves[1] / Q1 2018 Production



Source: Bloomberg, Peer filings
[1] PDP reserves for Berry and peers based on December 31, 2017 SEC Pricing.

Our Conventional, Low-Declining Asset Base

Our low production decline profile enhances capital flexibility through commodity price cycles and allows for efficient hedging of significant quantities of future expected production

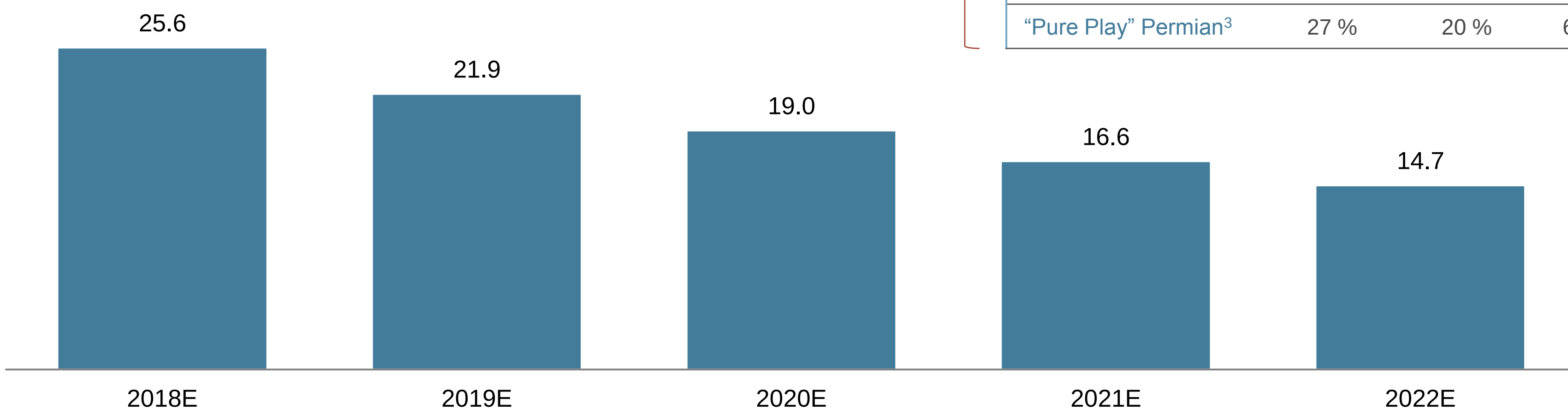
Berry Current PDP Production by Year[1] (MBoe/d)

% YoY Decline: **14 %** **13 %** **13 %** **12 %**

We estimate ~$110mm in annual capital to keep production volumes flat over the next three years

Berry is differentiated by unique characteristics of having both high oil content AND low declining production

Wood Mackenzie Estimates, excl. Berry	Decline Rate (CAGR)[4] 1st Year	Decline Rate (CAGR)[4] 3 Years	2018 % Oil
Berry[1]	14 %	13 %	80 %
Top Quartile	18 %	15 %	55 %
Broad E&Ps[2]	25 %	19 %	57 %
"Pure Play" Permian[3]	27 %	20 %	64 %

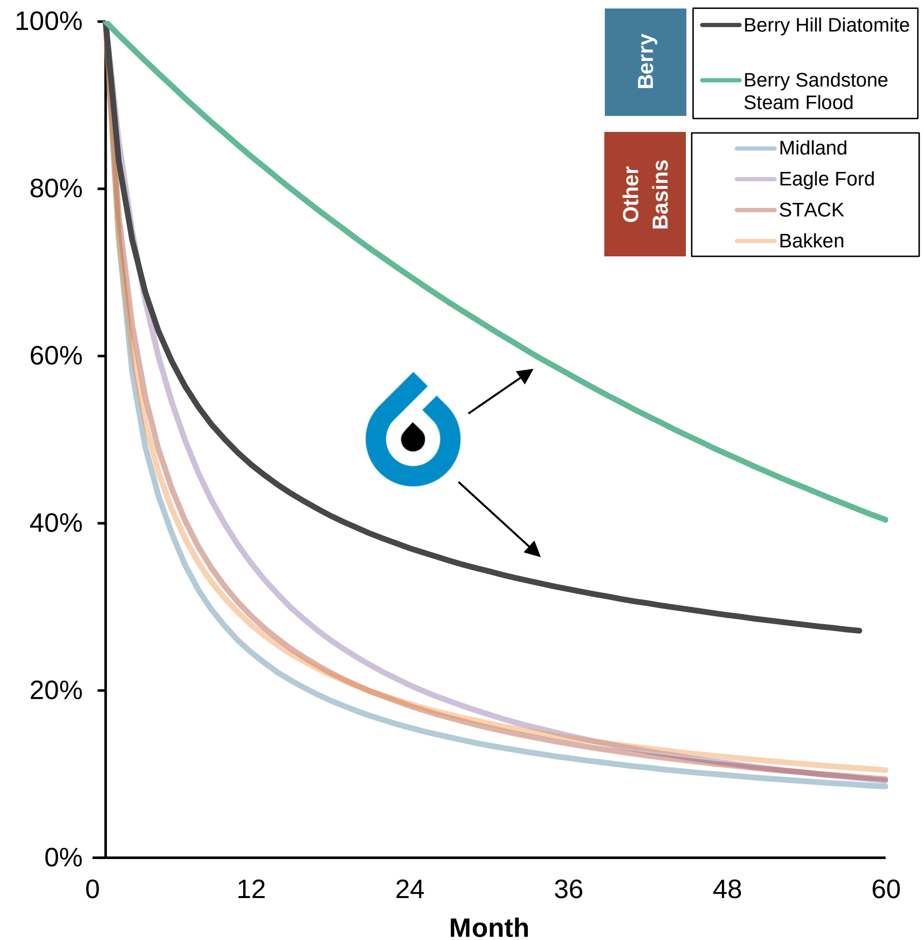


Source: Wood Mackenzie, Bloomberg (For Peers) | [1] Prepared based on 3rd party reserves report as of December 31, 2017 estimated using SEC Pricing. | [2] Broad E&Ps include APA, APC, CDEV, CPE, CRZO, CXO, DNR, DVN, ECA, EGN, EOG, FANG, HES, JAG, LPI, MRO, MTDR, MUR, NBL, NFX, OAS, PDCE, PE, PXD, QEP, SM, SRCI, WLL, WPX and XEC. | [3] "Pure Play" Permian include CDEV, CPE, CXO, EGN, FANG, JAG, LPI, PE and PXD. | [4] Peer set declines for 1st year and 3 years based on latest data from Wood Mackenzie, reflecting its pricing forecast updated as of May 2018, with regards to 2017 to 2020 PDP production. Berry declines for 1st year and 3 years based on 2018 to 2021 reserves report estimates.

Our Low Declining Wells and Production Base Mitigate "Treadmill" Conundrum Experienced in Unconventional Shale Plays

- The decline rates from our conventional oil development wells in California are significantly lower than those experienced in the top-tier U.S. oily shale plays
- The extensive history of development and production in our California fields provides a high degree of confidence and predictability
- Our California wells produce little to no gas
- With shale wells, there is limited visibility around long-term production profiles, including EURs and GORs
- The low declining nature of our development wells and PDPs result in a high degree of capital flexibility

% of Initial Rate From Peak Production (New Wells)

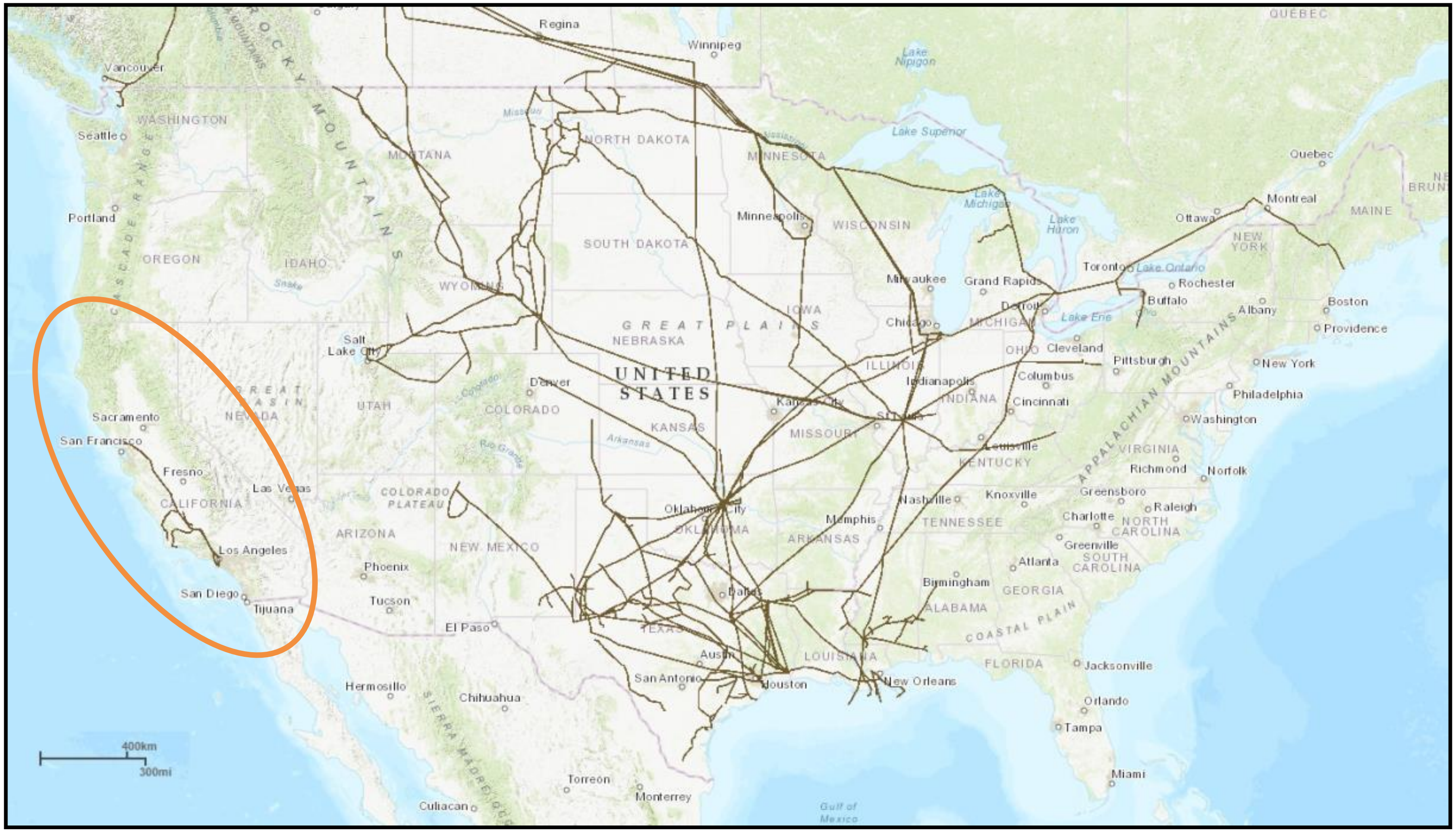


Source: Berry Reserves Database

Note: Berry Sandstone Steam Flood reaches peak production after approximately 12 months. Time period shown for Sandstone is shown from peak production and onward. The initial rate of production from peak production is determined using Berry's type curves. Please see slide 2 for a note regarding the preparation of Berry's type curves and slides 37-38 for more detailed information related to those curves.

3 California's Oil Market is Isolated From Rest of Lower 48

California's oil market is disconnected.
There are no major crude oil pipelines connecting it to the rest of the US.



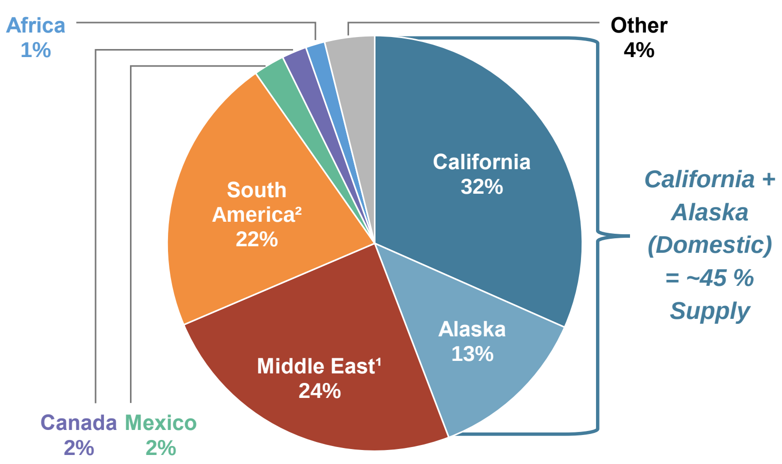
Crude Oil Pipelines in the U.S.

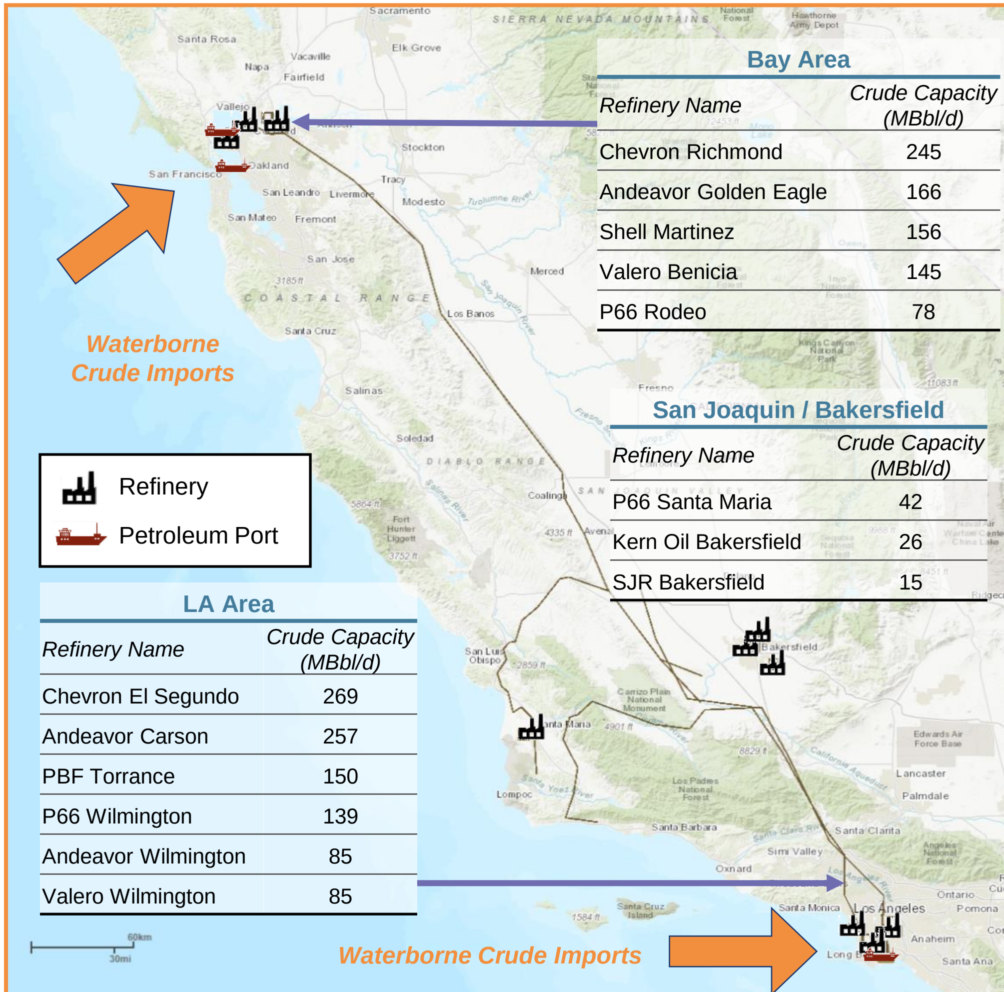
Source: EIA

3 Waterborne Supply Sources Drive a Brent-Influenced Pricing Dynamic in California

- California oil prices are Brent-influenced because California refiners import ~67% of supplies from waterborne sources, including >50% from non-US sources
- In 2017, ~46% of supply came from the Middle East[1] and South America[2]

2017 Sources of Feedstock for California





Bay Area

Refinery Name	Crude Capacity (MBbl/d)
Chevron Richmond	245
Andeavor Golden Eagle	166
Shell Martinez	156
Valero Benicia	145
P66 Rodeo	78

San Joaquin / Bakersfield

Refinery Name	Crude Capacity (MBbl/d)
P66 Santa Maria	42
Kern Oil Bakersfield	26
SJR Bakersfield	15

LA Area

Refinery Name	Crude Capacity (MBbl/d)
Chevron El Segundo	269
Andeavor Carson	257
PBF Torrance	150
P66 Wilmington	139
Andeavor Wilmington	85
Valero Wilmington	85

Source: California Almanac

[1] Largest Middle Eastern importers are Saudi Arabia, Iraq and Kuwait. | [2] Largest South American importers are Ecuador, Colombia and Brazil.

4 Our Geological Advantages and Lack of Shale Play Service Intensity Drive Substantially Lower and More Stable Drilling and Completion Costs

The lower cost nature of our equipment and the relative abundance of service providers allow for relative insulation from the cost inflation pressures experienced by E&Ps in unconventional plays

Equipment / Service	Shale Plays	Berry California	Berry Advantage
Drilling Rigs	■ High HP (1,500+), triple rig with top drives and multiple mud pumps ■ Larger pads required	■ Low HP (500), double rig with quick mobility ■ Smaller pads required	✓
Completion Equipment / Services	■ Both plug & perf and sliding sleeve use 40,000 HP 20+ tractor pad designs	■ Coiled tubing unit, fast delivery of sand, no need for rig or separate perforation equipment	✓
Proppant / Fluid	■ Intense use of proppant totaling >8 million pounds of sand ■ >2,000 pounds per foot of sand in horizontal sections with lateral length of 4,000' to 10,000'+	■ South Belridge Hill vertical well stimulations use a total of ~324,000 pounds of sand per well ■ Treating pressures under 2,000 psi	✓
Total Well Cost	■ Multi-million dollar well costs and surface facilities	■ $300,000 to $575,000 spud to production	✓
Pad Drilling	■ Significant working capital implications	■ No need for large scale pad drilling	✓
Spud-to-Sales	■ 20 to 40 days for single well ■ ~6 months per pad	■ 6 to 8 days for single well ■ 30 days or less for single pattern	✓

5 Significant Inventory of High Return Development Opportunities

Additional Upside

- ✓ Extended San Joaquin development
- ✓ Enhanced production techniques
- ✓ Enhanced drilling and completion techniques
- ✓ Cost / efficiencies upside

[1] IRRs based on Strip Pricing. Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. For a comparison to SEC Pricing, please see slides 48-49. | [2] IRRs calculated based on Berry's type curves and management's assumptions. Please see slide 2 for a note regarding the preparation of Berry's type curves and slides 36-38 for more detailed information related to those type curves.

6 Continued Improvement to EUR and Economic Upside

We are focused on enhancing the economic value of our existing reserve base and have identified several areas of potential upside

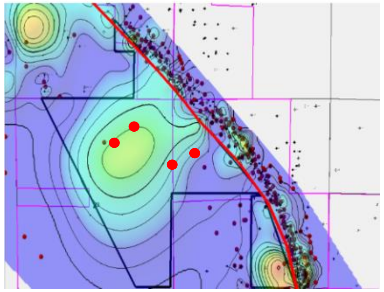
Enhanced Production Techniques	■ Change recovery process dynamics in Thermal Diatomite reservoir to enhance value versus rate — Notable change to Steam-Oil Ratio (SOR) versus previous recovery process ■ Investigate and implement enhanced water treating technologies in California ■ Implement cyclic production program in Utah in lieu of pump off controllers (no electricity available)
Enhanced Drilling and Completion Techniques	■ Change reservoir stimulation program in South Belridge Hill lease ■ Employ proppant-less slick water reservoir stimulation in Piceance assets for increased recovery and lower costs
Increased Steam Efficiency	■ Manage steam injection rates and placement in all thermal sandstone reservoirs to increase recovery factors ■ Manage surface heat loss resulting in lower costs and more effective downhole heating in the thermal Diatomite
Cost Management	■ Employ proactive preventative maintenance to prolong equipment life rather than reacting to equipment failures ■ Use of innovative technology for downhole recovery and surface processing in all areas
Deeper Reservoirs Field Extensions	■ Expand our geologic investigation to deeper reservoirs on and around our acreage below our existing producing reservoirs (>5,000 feet) ■ Expand strategic development beyond our current known productive areas

6 Chevron North Midway-Sunset Transaction

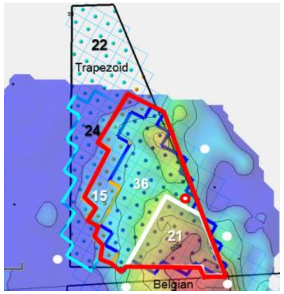
- Transaction typifies the opportunities we will continue to pursue around our existing position
- Finalized transaction on April 20, 2018
- No upfront capital
- Includes well commitments and options:
  - — Trapezoid (Thermal Diatomite)
  - — Olig-Potter (Potter and Tulare)
- Includes option for Origami (Thermal Diatomite)
  - — Appraisal wells drilled on Origami acreage and analysis is underway
- Began steaming existing Olig Potter wells
- Trapezoid initial drilling targeted for 2019

Net Pay and Proposed Locations

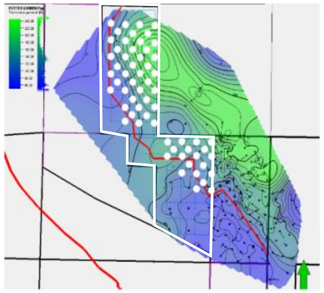
Origami - Diatomite

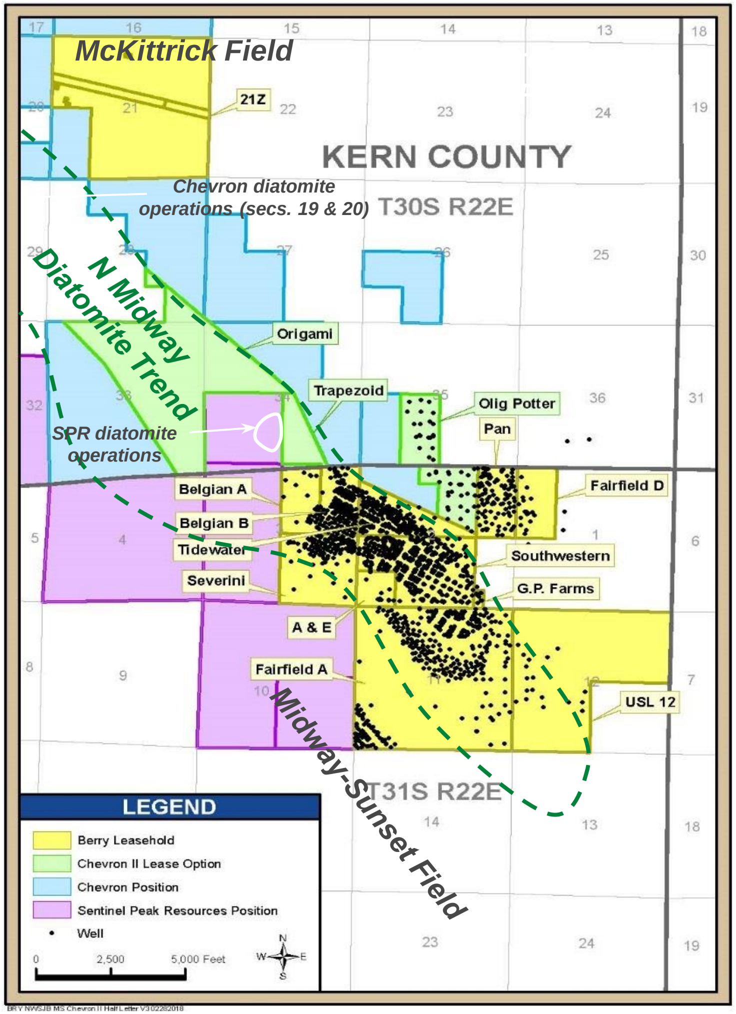


Trapezoid - Diatomite



Olig Potter - Potter Sand





7 Our Leverage is Low and our Liquidity is Strong

Current Capital Structure

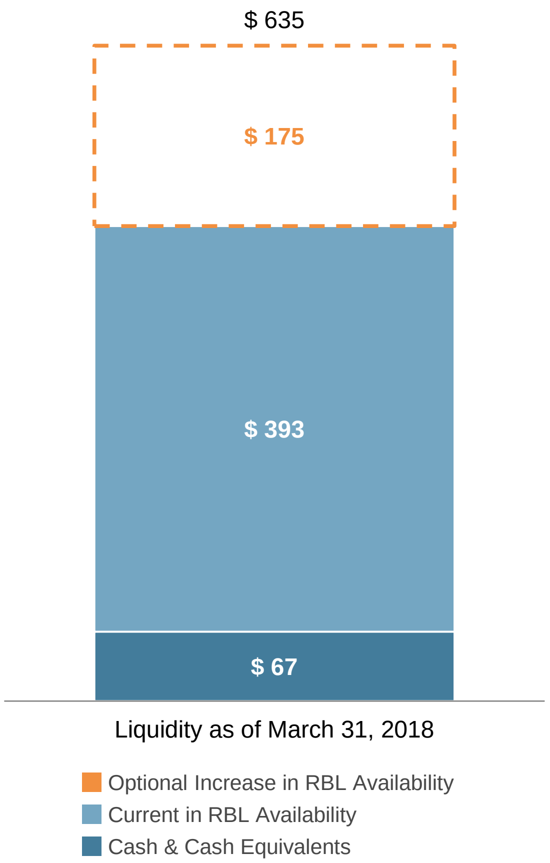
Capitalization	March 31,2018
Cash & Cash Equivalents	$ 67
RBL Facility	-
Senior Notes	400
Total Debt	**$ 400**
Net Debt	**$ 333**

Selected Operating Metrics	
Q1 2018 Adjusted EBITDA Unhedged ($mm)[1]	$ 62.4
Q1 2018 Production (Mboe/d)	26.2
Proved Reserves[2] (MMboe)	141

Cash Flow Metrics	
Debt / LQA Adjusted EBITDA Unhedged[1]	1.6 x
Net Debt / LQA Adjusted EBITDA Unhedged[1]	1.3

Liquidity Analysis	March 31,2018
Cash & Cash Equivalents[3]	$ 67
(+) RBL Availability	400
(-) Outstanding Borrowings[3]	-
(-) Outstanding Letters of Credit	(7)
Total Liquidity	**$ 460**

Current Liquidity ($mm)



Note: LQA refers to Q1 2018 annualized results for the quarter ended March 31, 2018.

[1] Adjusted EBITDA Unhedged is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA Unhedged to the most directly comparable financial measure calculated and presented in accordance with GAAP, please see slide 45.

[2] Prepared based on 3rd party reserves report dated as of December 31, 2017 estimated using SEC Pricing.

[3] As of June 30, 2018, we had $5mm in cash & cash equivalents and $66mm in outstanding borrowings.

III. Financial Attributes

Ethel D lease outside of Taft, California

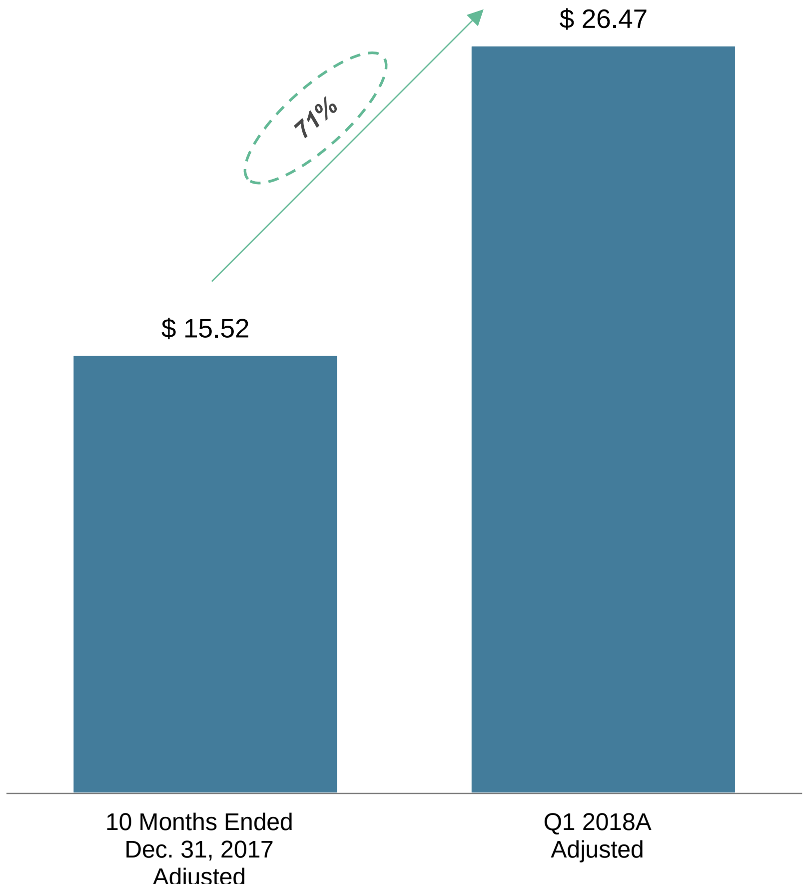
We Believe That Our Differentiated Asset Base and Operations Will Result in…

- ✓ Top-tier corporate level returns
- ✓ Long-term capital efficient growth
- ✓ High degree of capital flexibility with low breakeven oil prices
- ✓ Positive levered free cash flow through commodity price cycles
- ✓ Ability and intention to return capital to shareholders

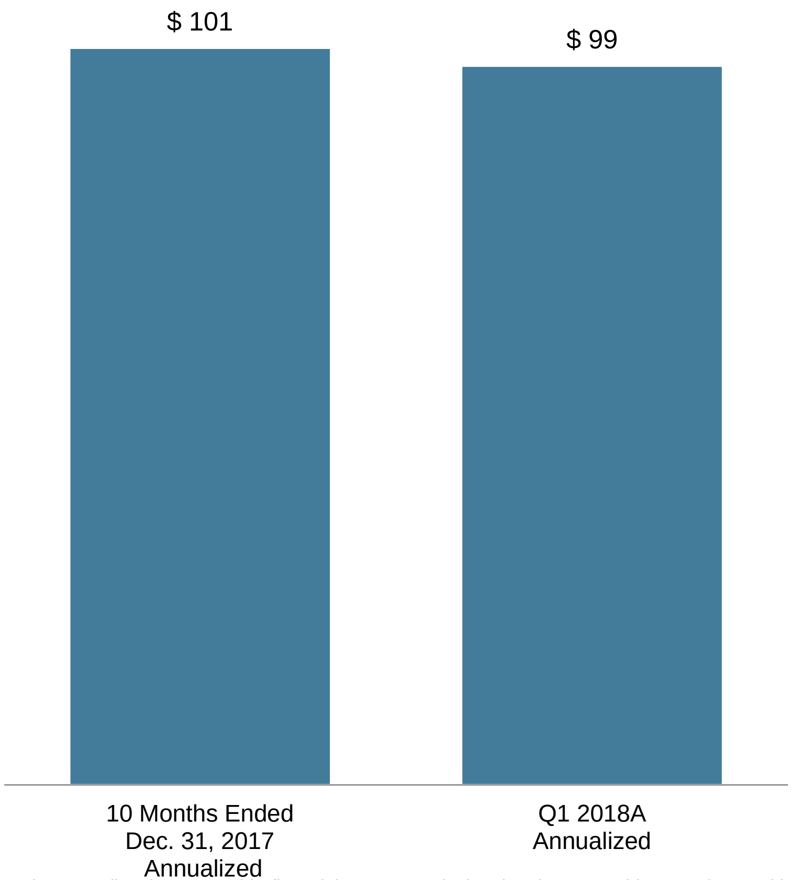
We Generate Strong Adj. EBITDA Margins and Positive Free Cash Flow

Historical Adjusted EBITDA Unhedged Margin[1] ($/Boe)

Average Brent Price ($/Bbl): $54.65 | $67.16



Historical Adjusted EBITDA less Capex[2] ($mm)



[1] Adjusted EBITDA Unhedged is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA Unhedged to the most directly comparable financial measure calculated and presented in accordance with GAAP, please see slide 45. Adjusted EBITDA Unhedged Margin is defined as Adjusted EBITDA Unhedged divided by total production for the respective period (9,443 Mboe for Ten Months Ended December 31,2017 and 2,356 Mboe for Q1 2018A). A reconciliation can be found on slide 45. | [2] Adjusted EBITDA less Capital Expenditures is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA less Capital Expenditures to the most directly comparable financial measure calculated and presented in accordance with GAAP, please see slide 46.

III. Financial Policy

Header in the Thermal Diatomite area, North Midway Sunset

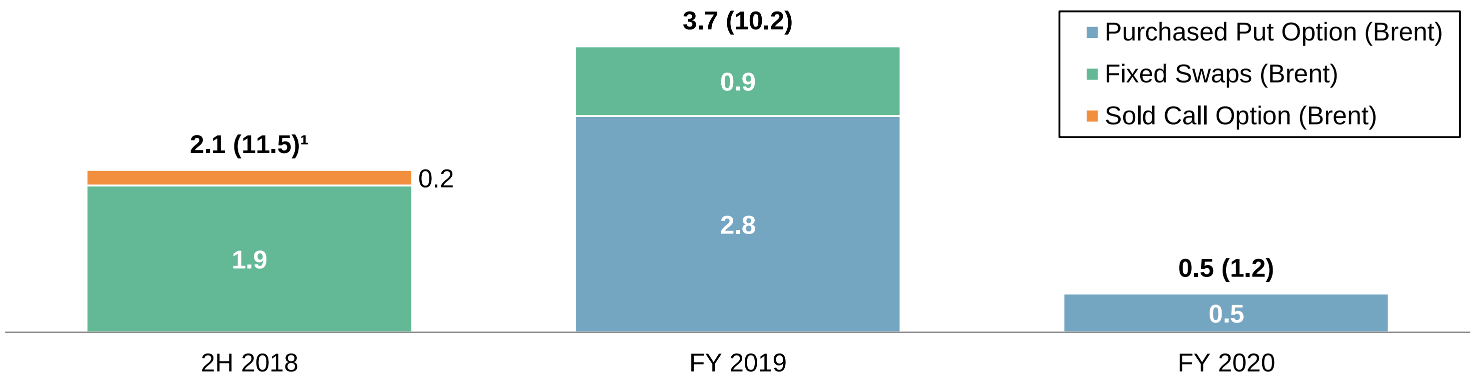
Our Financial Policy

Prudent Balance Sheet Management	■ Target Net Debt to EBITDA of 1.5 – 2.0x or lower through commodity price cycles ■ Deleveraging will be achieved through organic growth and excess levered free cash flow
Return Capital to Shareholders via Quarterly Dividend	■ Intend to return capital to shareholders quarterly ■ Initiating quarterly dividend of $0.12 / share as of Q3 2018
Long-Term Hedging	■ Strategy is to secure revenue stream to fund capital needs ■ Hedge target is to cover operating expenses and fixed charges 2 years out ■ Physical gas hedges used to manage cost and ensure supply
Capital Spend	■ Use levered free cash flow from operations to fund maintenance and organic growth opportunities ■ Use other sources of capital for acquisitions that support the long-term leverage profile ■ Maintain capital flexibility; we can cut capex in a downturn

Prudent Commodity Price Risk Management

High degree of margin visibility via proactive hedging program and cost stability

Hedge Volumes in MMBbls (MBbl/d)



	Weighted Average Prices		
Fixed Swap (Brent)	$ 75.13	$ 75.66	-
Sold Call Option (Brent)	$ 81.67	-	-
Purchased Put Option (Brent)[2]	-	$ 65.00	$ 65.00
Total	$ 75.70	$ 67.57	$ 65.00
Brent (30-Jun-2018)	$ 78.69	$ 75.08	$ 70.19

Note: Prices are weighted average.
[1] Calculations based on 184 days as of 30-Jun-2018. | [2] Excludes deferred premium.

IV. Asset Overview

A view of Berry's Homebase acreage in South Midway-Sunset

Our Large, Conventional and Diversified Asset Base is Oil-Weighted and Valuable

Basin	May 2018 Strip Net Proved Reserves[1] (MMBoe) / % PD	1Q18 Avg. Net Production (MBoe/d)	1Q18 % Oil Production	May 2018 Strip 1P PV-10[1,2] ($mm) / % of Total	Avg. WI / NRI[3,4]	Gross Drilling Inventory (Identified)	March 2018 Producing Wells, Gross[4,5]	1Q18 Net Acreage
	115 / 71 %	26	81 %	$ 1,862	97 % / 87 %	7,053	3,795	116,582
California	95 / 66 %	19	100 %	$ 1,762 / 95 %	99 % / 94 %	4,858	2,600	7,945
Uinta	15 / 100 %	5	46 %	$ 91 / 5 %	95 % / 78 %	1,245	909	96,096
Piceance	3 / 100 %	2	1 %	$ 4 / 0 %	72 % / 62 %	870	170	8,008
East Texas	2 / 100 %	1	0 %	$ 5 / 0 %	99 % / 74 %	80	116	4,533

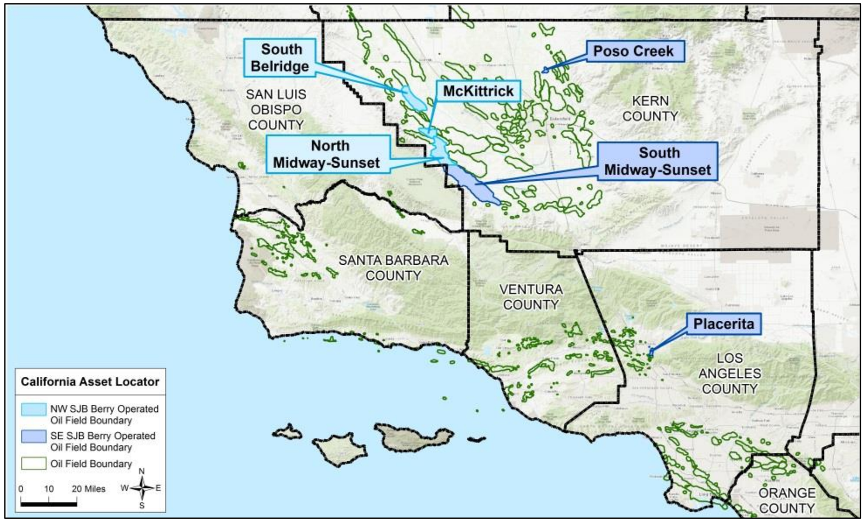
[1] Prepared based on 3rd party reserves report addendum as of June 28, 2018 and closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. For a comparison to SEC Pricing, please see slides 48-49. | [2] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10 . | [3] Weighted average WI across active wells as of March 31, 2018 and weighted average NRI for March 2018. | [4] Excludes 91 wells in the Piceance basin each with a 5% working interest and eleven wells in the Permian basin all with less than 0.1% working interest. | [5] Includes steam flood and water flood injection wells in California.

Our California Assets

Asset Overview

- We have a concentrated position in California's San Joaquin Basin
- Production is primarily oil from prolific fields including Midway-Sunset, South Belridge and McKittrick on the west side of the Basin
- Thermal recovery techniques include cyclic and continuous injection in heavy oil diatomite and sandstone reservoirs
- 99% Held By Production in California

Map of Operations



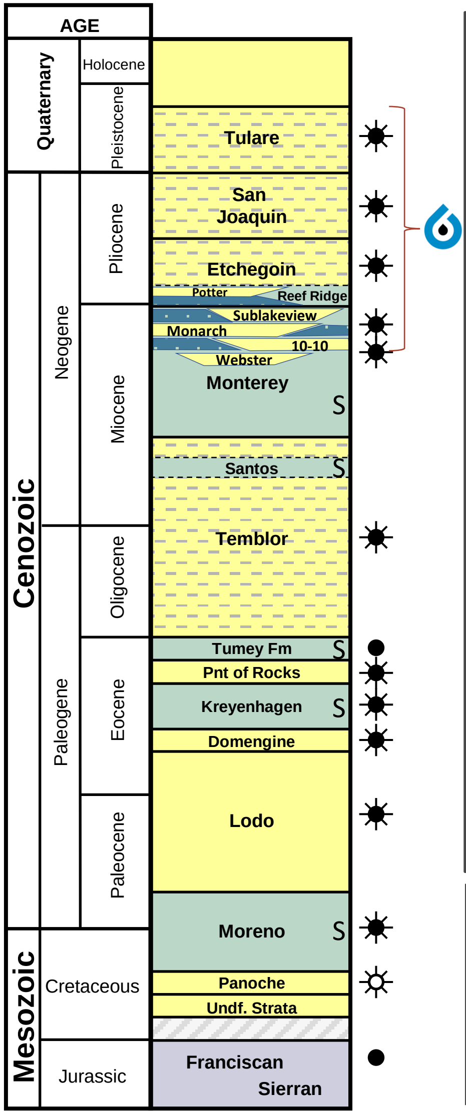
Note: Prepared based on 3rd party reserves report addendum as of June 28, 2018 and closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. For a comparison to SEC Pricing, please see slides 48-49. | [1] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10. | [2] Weighted average WI across active wells as of March 31, 2018 and weighted average NRI for March 2018. | [3] Includes steam flood and water flood injection wells in California.

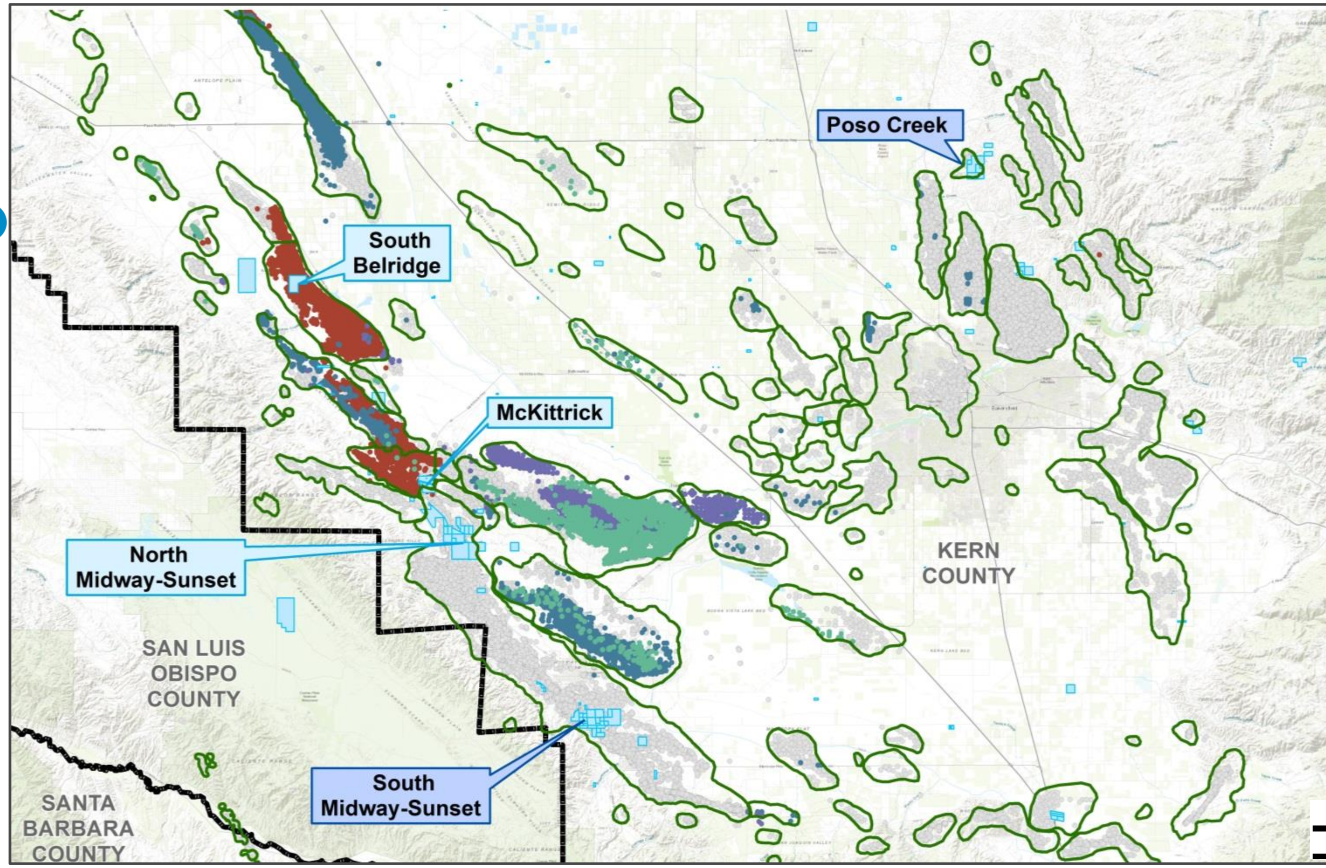
- Drilling opportunities exist in each asset area allowing for production growth and increased recovery and reserves
  - Prolific history of results allow for predictable results
  - Low D&C costs and quick spud to production times enhance execution of development plans
- Existing infrastructure in place to allow for production growth and improve upstream economics
  - 5 Cogeneration plants in Midway-Sunset and Placerita with ~108 MW of nameplate electrical power and ~32,000 barrels of steam per day for the three months ended March 31, 2018

Asset Description

California	
Proved Reserves (May-18 Strip Pricing)	95 MMBoe
1P PV-10[1] (May-18 Strip Pricing)	$1,762mm
Net Acreage	7,945
Core Areas	Southeast San Joaquin Northwest San Joaquin
Q1 2018 Net Production (Mboe/d)	19
Average WI / NRI[2]	99 % / 94 %
Producing Wells, Gross[3]	2,600
Depth of Target Formations	800’ – 2,000’
Current Steam Generation Capacity	> 200 Mbpsd

Our California Operational Areas and Producing Intervals

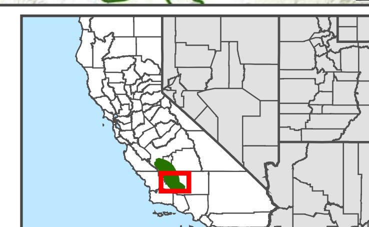




Berry Producing Intervals
Gas & Oil Production
Gas Production
Oil Production
S Source Rock
Sandstones
Sandstones & Mudstones
Diatomite
Mudstones
Metamorphic or Igneous Bsmt

Producing Reservoirs

- ETCHEGOIN
- MONARCH / SUB LAKEVIEW
- MONTEREY
- SAN JOAQUIN
- TULARE
- UNDIFFERENTIATED
- Berry Position
- Oil Field Boundary

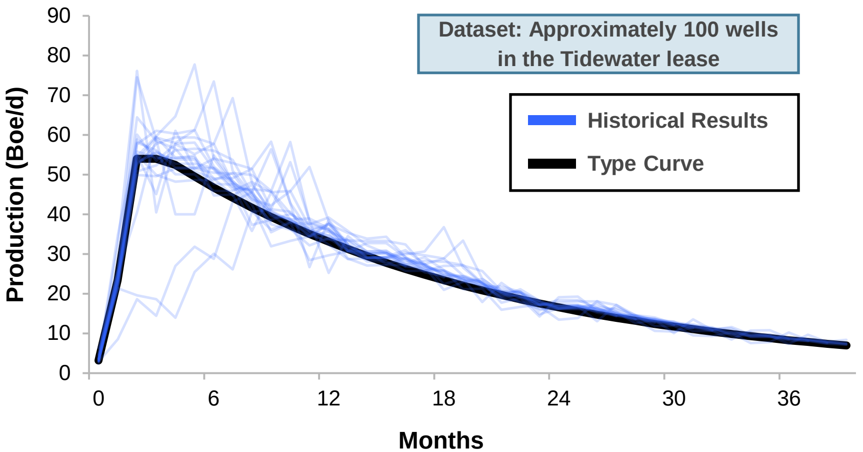


Berry's Completion and Recovery Mechanisms

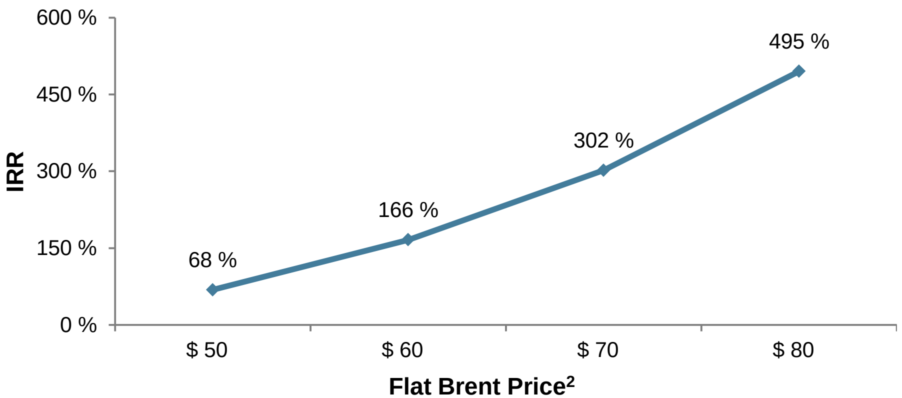
State	Project Type	Well Type	Completion Type	Recovery Mechanism	Depth (ft.)
California	Hill Diatomite (non-thermal)	Vertical	Low intensity pin point fracture stimulation	Pressure Depletion augmented with water injection	1,300 – 2,000
	Thermal Diatomite	Vertical	Short interval perforations (dual completions)	Cyclic steam injection (steam and flow mechanics)	300 – 2,000
	Thermal Sandstones	Vertical / Horizontal	Perforations/Slotted liner/gravel pack	Continuous and cyclic steam injection	500 – 2,500
Utah	Uinta Green River / Wasatch Sands	Vertical / Horizontal	Low intensity fracture stimulation	Pressure Depletion	5,000 – 8,000
Colorado	Piceance	Vertical	Proppantless Slick Water fracture stimulation	Pressure Depletion	7,500 – 12,000

San Joaquin – Thermal Diatomite Well Type Curve[1] Overview

Type Curve and Historical Well Results | (Boe/d)



Economics Across Various Prices



Asset Information

Area	NW San Joaquin Basin
Reservoir	Thermal Diatomite
Number of Wells (Tier 1 / Total)	774 / 1,678
WI / NRI	100 % / 97 %

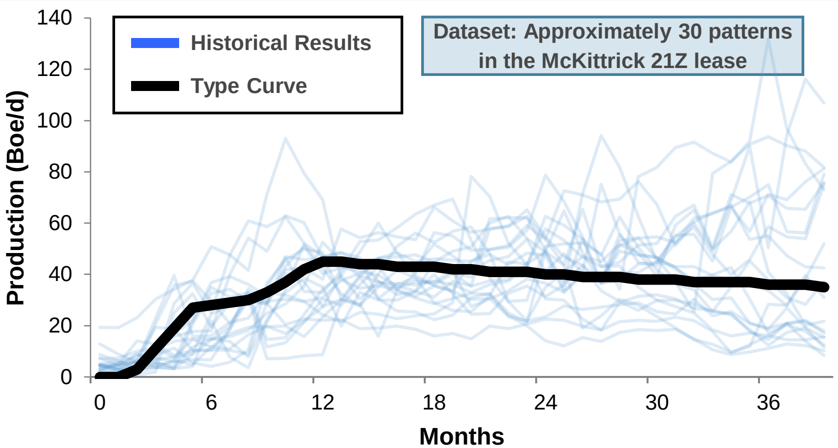
Aggregate Well Type Curve Assumptions and Results

Gross Capex ($mm / well)	$ 0.5
Net EUR (Mboe)	29
% Oil	100 %
IP90 Production (Boe/d)	44.4
Brent Differential ($/Bbl)	$(3.63)
Fixed Opex per well ($k/month)	$ 2.83
Variable Opex[3] per boe ($/Boe)	$ 2.13
Steam[3] ($/Boe)	$ 8.94
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[4] as of May 31, 2018	359 %[5]
PV-10[6] ($mm) per well	$ 0.7

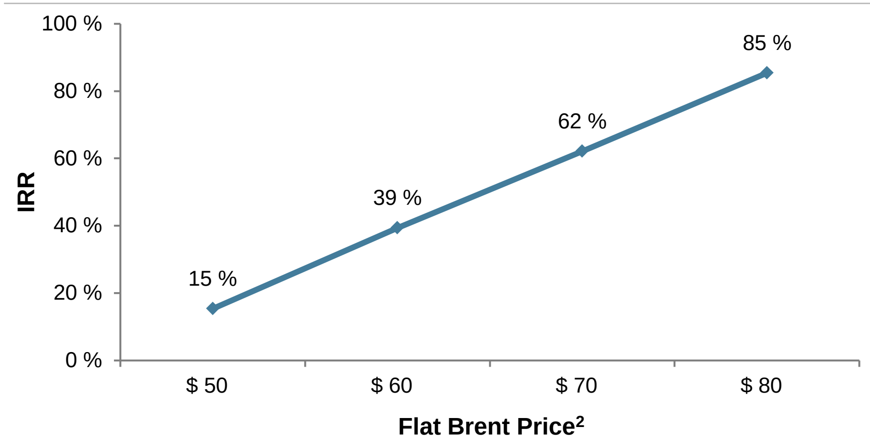
[1] Please see slide 2 for a note regarding the preparation of Berry's type curves. | [2] Assumes flat $3 Henry Hub gas price. | [3] LOE costs based on run-rate average over 24 months of the well. | [4] Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. For a comparison to SEC Pricing, please see slides 48-49. | [5] Management IRRs differ significantly from DeGoyler and MacNaughton reserve report IRRs, which are capped at 100% by ARIES Petroleum Economics and Reserves Software. | [6] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.

San Joaquin – Sandstone Flood Pattern Type Curve[1] Overview

Type Curve and Historical Well Results | (Boe/d)



Economics Across Various Prices



Asset Information

Area	San Joaquin Basin
Reservoir	Multiple
Drilling Pattern	2 Producing Wells: 1 Injector Well
Number of Wells[3] (Tier 1 / Total)	1,860 / 2,284
WI / NRI	100 % / 95 %

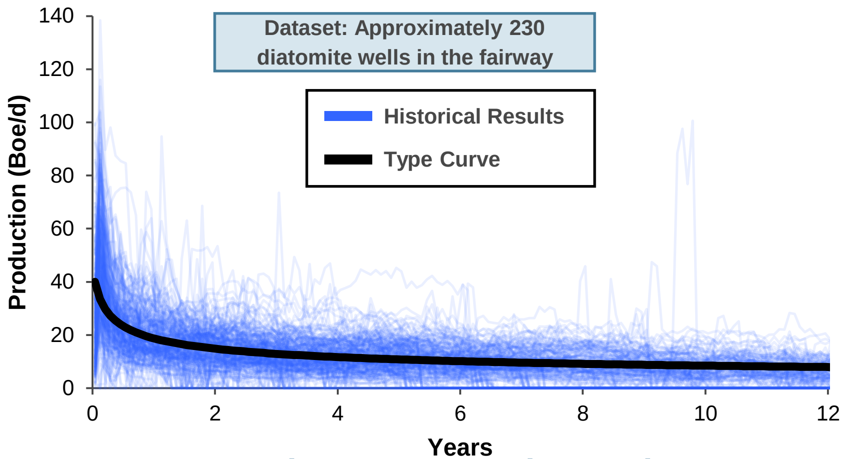
Aggregate Pattern Type Curve Assumptions and Results

Gross Capex ($mm / pattern)	$ 1.2
Net EUR (Mboe)	114
% Oil	100 %
IP90 Production (Boe/d)	19.9
Brent Differential ($/Bbl)	$(5.63)
Fixed Opex per pattern ($k/month)	$ 4.40
Variable Opex[4] per boe ($/Boe)	$ 2.17
Steam[4] ($/Boe)	$ 16.67
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[5] as of May 31, 2018	65 %
PV-10[6] ($mm) per pattern	$ 1.6

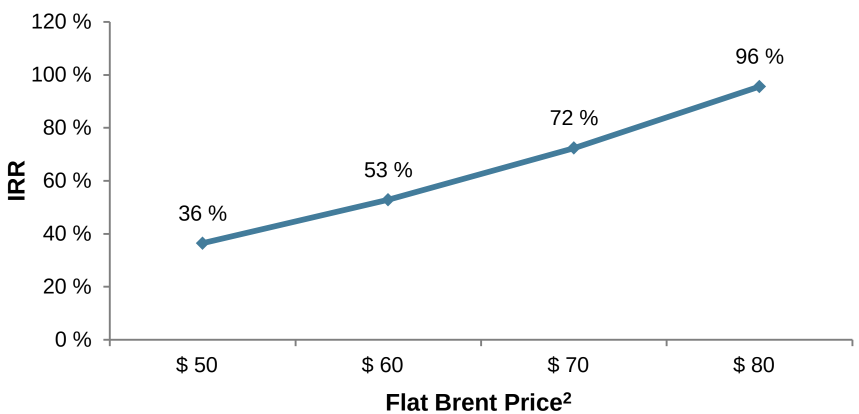
[1] Please see slide 2 for a note regarding the preparation of Berry's type curves. | [2] Assumes flat $3 Henry Hub gas price. | [3] Includes producing wells and injector wells. | [4] LOE costs based on run-rate average over 24 months of the well. | [5] Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. For a comparison to SEC Pricing, please see slides 48-49. | [6] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.

San Joaquin – Hill Diatomite Fairway Pattern Type Curve[1] Overview

Type Curve and Historical Well Results | (Boe/d)



Economics Across Various Prices



Asset Information

Area	San Joaquin Basin
Reservoir	Diatomite
Drilling Pattern	3 Producing Wells: 1 Injector Well
Number of Wells[3] (Tier 1 / Total)	311 / 896
WI / NRI	100 % / 100 %

Aggregate Pattern Type Curve Assumptions and Results

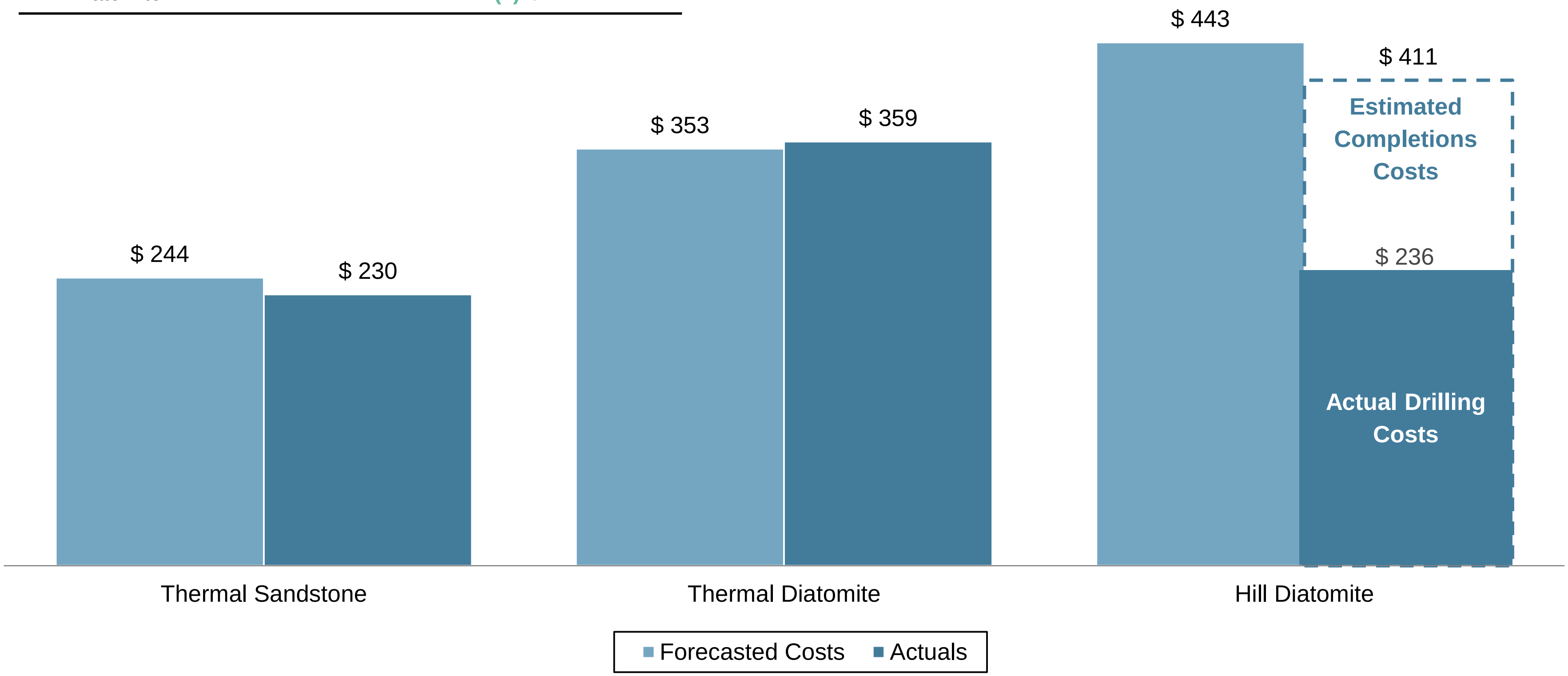
Gross Capex ($mm / pattern)	$ 2.2
Net EUR (Mboe)	139
% Oil	100 %
IP90 Production (Boe/d)	94.8
Brent Differential ($/Bbl)	$ 1.13
Fixed Opex per pattern ($k/month)	$ 4.94
Variable Opex[4] per boe ($/Boe)	$ 1.68
Steam[4] ($/Boe)	-
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[5] as of May 31, 2018	78 %
PV-10[6] ($mm) per pattern	$ 3.5

[1] Please see slide 2 for a note regarding the preparation of Berry's type curves. | [2] Assumes flat $3 Henry Hub gas price. | [3] Includes producing wells and injector wells. | [4] LOE costs based on run-rate average over 24 months of the well. | [5] Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. For a comparison to SEC Pricing, please see slides 48-49. | [6] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.

Our Actual Realized D&C Costs Have Aligned Closely with AFEs

D&C Cost Per Well ($ in thousands)

California Area	Over (Under) Budget
Thermal Sandstone	(6)%
Thermal Diatomite	2 %
Hill Diatomite	(7)%



Note: Average realized cost based on 2017 data.

Concluding Remarks

- ***Berry*** **is a highly differentiated E&P company with a clear strategic, operational and financial vision**

Conventional, stable, oil-weighted asset base	✓
Favorable West Coast crude pricing dynamics	✓
Positive levered free cash flow through the cycle	✓
Long inventory life of high return oil locations	✓
Predictable cost structure	✓
Strategic and organic growth opportunities	✓
Strong balance sheet	✓
Prudently returning capital to shareholders	✓

A. Other Reference Materials

Historical Well List for Hill Diatomite Fairway

#	Well Name	Date	API
1	HILL 412A	1989-11-01	04029845870000
2	HILL 422	1992-03-01	04029893650000
3	HILL 511H	2006-08-01	04030298590000
4	HILL 523B	2006-08-01	04030294830000
5	HILL 612D	2013-04-01	04030478850000
6	HILL 622A	2012-02-01	04030443100000
7	HILL 622B	2011-04-01	04030416260000
8	HILL 421F	2002-05-01	04030201660000
9	HILL 421K	2002-05-01	04030201700000
10	HILL 421L	2002-06-01	04030201720000
11	HILL 422K	2002-05-01	04030201710000
12	HILL 423D	2002-07-01	04030202630000
13	HILL 433A	2002-07-01	04030203760000
14	HILL 433B	2002-07-01	04030204060000
15	HILL 433C	2002-07-01	04030205000000
16	HILL 522	2005-04-01	04030263730000
17	HILL 522A	2005-04-01	04030263750000
18	HILL 523	2005-04-01	04030263740000
19	HILL 533	2003-10-01	04030226380000
20	HILL 533A	2003-10-01	04030226440000
21	HILL 533B	2007-11-01	04030306480000
22	HILL 534	2003-12-01	04030226390000
23	HILL 534A	2003-12-01	04030226450000
24	HILL 544	2003-12-01	04030226410000
25	HILL 544A	2003-12-01	04030229900000
26	HILL 544B	2003-12-01	04030229470000
27	HILL 544C	2003-12-01	04030229960000
28	HILL 622	2012-03-01	04030445210000
29	HILL 623	2012-01-01	04030443110000
30	HILL 633	2012-02-01	04030443120000
31	HILL 633B	2011-12-01	04030443130000
32	HILL 644B	2012-01-01	04030443660000
33	HILL 644C	2013-04-01	04030478330000
34	HILL 644E	2013-05-01	04030478340000
35	HILL 421B	2001-08-01	04030176110000
36	HILL 421C	2001-09-01	04030176120000
37	HILL 421D	2001-08-01	04030176130000
38	HILL 421E	2001-08-01	04030176140000
39	HILL 421I	2002-05-01	04030201680000
40	HILL 421J	2002-05-01	04030201690000
41	HILL 432A	2001-08-01	04030142440000
42	HILL 432B	2001-08-01	04030178630000
43	HILL 432C	2002-07-01	04030202380000
44	HILL 432L	2002-09-01	04030203810000
45	HILL 433E	2002-08-01	04030203770000
46	HILL 433F	2002-08-01	04030203790000
47	HILL 443M	2002-06-01	04030202640000
48	HILL 443N	2002-06-01	04030202650000
49	HILL 444B	2002-06-01	04030202440000
50	HILL 444C	2002-06-01	04030202450000
51	HILL 543	2003-10-01	04030226400000
52	HILL 543A	2003-10-01	04030228700000
53	HILL 544D	2003-12-01	04030229480000
54	HILL 544E	2003-12-01	04030229490000
55	HILL 621	2012-04-01	04030443090000
56	HILL 621A	2011-04-01	04030416250000
57	HILL 621C	2012-03-01	04030445200000
58	HILL 622D	2012-03-01	04030445220000
59	HILL 632E	2013-04-01	04030479800000
60	HILL 632H	2013-04-01	04030479810000
61	HILL 632K	2013-04-01	04030479820000
62	HILL 633A	2011-08-01	04030416320000
63	HILL 643B	2012-02-01	04030416410000
64	HILL 431C	1999-12-01	04030142470000
65	HILL 432F	2002-09-01	04030203780000
66	HILL 443B	2001-08-01	04030176150000
67	HILL 443C	2001-08-01	04030176160000
68	HILL 443F	2002-07-01	04030202480000
69	HILL 443J	2002-06-01	04030202490000
70	HILL 454C	2002-07-01	04030202460000
71	HILL 454D	2002-07-01	04030202470000
72	HILL 543B	2003-10-01	04030229940000
73	HILL 543C	2003-10-01	04030229950000
74	HILL 553F	2005-06-01	04030266080000
75	HILL 631	2012-02-01	04030416270000
76	HILL 631E	2011-04-01	04030416300000
77	HILL 632	2011-12-01	04030444310000
78	HILL 632B	2011-07-01	04030416310000
79	HILL 643	2011-07-01	04030416390000
80	HILL 643E	2013-04-01	04030479240000
81	HILL 643G	2013-05-01	04030478860000
82	HILL 644	2011-08-01	04030416430000
83	HILL 644A	2011-04-01	04030416440000
84	HILL 654	2011-11-01	04030443680000
85	HILL 421G	2002-06-01	04030201670000
86	HILL 431B	1999-12-01	04030142450000
87	HILL 432J	2002-08-01	04030204000000
88	HILL 432K	2002-08-01	04030204010000
89	HILL 442I	2002-09-01	04030203990000
90	HILL 443D	2002-09-01	04030203950000
91	HILL 443E	2002-09-01	04030203960000
92	HILL 443G	2002-08-01	04030205010000
93	HILL 443I	2002-08-01	04030203800000
94	HILL 443K	2002-09-01	04030204020000
95	HILL 443L	2002-08-01	04030204030000
96	HILL 453L	2002-08-01	04030204040000
97	HILL 553E	2005-07-01	04030266880000
98	HILL 631A	2012-02-01	04030416280000
99	HILL 631D	2011-04-01	04030416290000
100	HILL 631F	2012-03-01	04030444300000
101	HILL 642	2011-07-01	04030416370000
102	HILL 642C	2011-12-01	04030444320000
103	HILL 643C	2011-08-01	04030416420000
104	HILL 643K	2013-04-01	04030478320000
105	HILL 653F	2013-05-01	04030478380000
106	HILL 654A	2011-11-01	04030443690000
107	HILL 654F	2013-05-01	04030478400000
108	HILL 431	1999-12-01	04030135340000
109	HILL 431A	1999-12-01	04030135350000
110	HILL 431D	1999-12-01	04030138830000
111	HILL 431E	1999-12-01	04030138840000
112	HILL 442B	1999-11-01	04030137360000
113	HILL 442C	1999-12-01	04030137370000
114	HILL 442D	1999-11-01	04030135380000
115	HILL 442E	1999-12-01	04030135390000
116	HILL 443	1999-12-01	04030137350000
117	HILL 443A	1999-12-01	04030135370000
118	HILL 464	1991-12-01	04029893680000
119	HILL 542B	2005-05-01	04030263760000
120	HILL 542C	N/A	04030263770000
121	HILL 553B	2005-06-01	04030266860000
122	HILL 553C	2005-08-01	04030266870000
123	HILL 554X	N/A	04029502860000
124	HILL 631C	2012-02-01	04030445230000
125	HILL 641A	2011-04-01	04030416340000
126	HILL 642B	2011-08-01	04030416380000
127	HILL 643A	2011-08-01	04030416400000
128	HILL 653A	2011-07-01	04030416460000
129	HILL 664	2011-07-01	04030416480000
130	HILL 441G	1999-12-01	04030135410000
131	HILL 442J	2002-08-01	04030206850000
132	HILL 452F	2002-08-01	04030205410000
133	HILL 453B	1991-12-01	04029893670000
134	HILL 453E	2002-08-01	04030203970000
135	HILL 453F	2002-08-01	04030203980000
136	HILL 464A	1994-02-01	04030015650000
137	HILL 464B	1994-01-01	04030015660000
138	HILL 541D	2005-07-01	04030263780000
139	HILL 541E	2005-04-01	04030265810000
140	HILL 541F	2005-05-01	04030263790000
141	HILL 541G	2005-05-01	04030263800000
142	HILL 641	2012-01-01	04030416330000
143	HILL 641B	2011-08-01	04030416350000
144	HILL 642D	2013-03-01	04030478310000
145	HILL 652	2011-08-01	04030416450000
146	HILL 652C	2013-03-01	04030478360000
147	HILL 653H	2012-12-01	04030478390000
148	HILL 664B	2013-06-01	04030478460000
149	HILL 664F	2013-05-01	04030478470000
150	HILL 441	1992-01-01	04029893660000
151	HILL 441D	1999-12-01	04030137380000
152	HILL 441E	1999-12-01	04030137390000
153	HILL 441F	1999-12-01	04030137400000
154	HILL 441H	1999-12-01	04030135420000
155	HILL 441I	1999-11-01	04030137410000
156	HILL 442F	1999-11-01	04030135400000
157	HILL 442G	1999-12-01	04030135430000
158	HILL 452A	1994-02-01	04030015610000
159	HILL 463A	1994-02-01	04030015640000
160	HILL 464C	1994-01-01	04030015670000
161	HILL 464D	1996-11-01	04030054220000
162	HILL 464H	1997-10-01	04030089740000
163	HILL 464I	1998-06-01	04030090910000
164	HILL 474B	1991-12-01	04029893690000
165	HILL 474L	2002-09-01	04030204050000
166	HILL 552	2003-12-01	04030229500000
167	HILL 552A	2003-12-01	04030229910000
168	HILL 553DH	2005-06-01	04030268680000
169	HILL 563G	2003-12-01	04030229510000
170	HILL 563H	2003-12-01	04030229520000
171	HILL 641C	2012-01-01	04030416360000
172	HILL 652A	2011-12-01	04030444330000
173	HILL 664H	2013-08-01	04030478870000
174	HILL 664K	2013-08-01	04030478880000
175	HILL 664P	2013-01-01	04030478480000
176	HILL 674L	2014-04-01	04030478890000
177	HILL 674M	2013-01-01	04030478520000
178	HILL 674P	2013-01-01	04030478530000
179	HILL 451	1989-12-01	04029848740000
180	HILL 474C	1996-11-01	04030054260000
181	HILL 474E	1997-07-01	04030074500000
182	HILL 474G	1997-07-01	04030054140000
183	HILL 551B	2005-05-01	04030266060000
184	HILL 563C	2003-09-01	04030226480000
185	HILL 563D	2003-09-01	04030226490000
186	HILL 652D	2013-03-01	04030478370000
187	HILL 663D	2011-08-01	04030416470000
188	HILL 674C	2011-11-01	04030416490000
189	HILL 674E	2011-11-01	04030443720000
190	HILL 674G	2013-01-01	04030478490000
191	HILL 441C	1996-11-01	04030054270000
192	HILL 451G	2001-08-01	04030176170000
193	HILL 451H	2001-08-01	04030176180000
194	HILL 451J	2001-07-01	04030180680000
195	HILL 451K	2001-08-01	04030180690000
196	HILL 452D	2001-08-01	04030176190000
197	HILL 452E	2001-08-01	04030176200000
198	HILL 462L	2001-08-01	04030176220000
199	HILL 462M	2001-08-01	04030176230000
200	HILL 473C	1997-05-01	04030074470000
201	HILL 474I	1997-05-01	04030074570000
202	HILL 474K	1997-05-01	04030074590000
203	HILL 551	2005-05-01	04030266030000
204	HILL 551A	2005-07-01	04030266040000
205	HILL 562	2003-09-01	04030226420000
206	HILL 562A	2003-09-01	04030226460000
207	HILL 563	2003-12-01	04030229890000
208	HILL 563A	2003-12-01	04030229920000
209	HILL 573	2003-12-01	04030229530000
210	HILL 574	2006-08-01	04030302330000
211	HILL 662	2011-12-01	04030443700000
212	HILL 662A	2013-02-01	04030478410000
213	HILL 673C	2011-11-01	04030443710000
214	HILL 674H	2013-01-01	04030478500000
215	HILL 674K	2012-10-01	04030478510000
216	HILL 461A	1997-10-01	04030076560000
217	HILL 461J	2001-07-01	04030176210000
218	HILL 462E	1997-09-01	04030082820000
219	HILL 462G	1997-11-01	04030082840000
220	HILL 462I	1998-01-01	04030076510000
221	HILL 462Q	2001-07-01	04030176240000
222	HILL 462R	2001-07-01	04030176250000
223	HILL 462S	2001-08-01	04030176260000
224	HILL 473E	1997-04-01	04030074490000
225	HILL 473G	1997-04-01	04030074520000
226	HILL 473I	1997-05-01	04030074560000
227	HILL 484	1997-12-01	04030089750000
228	HILL 584C	2006-08-01	04030302340000
229	HILL 584E	2006-08-01	04030302350000
230	HILL 651	2011-11-01	04030443670000
231	HILL 662M	2013-02-01	04030478440000
232	HILL 662N	2013-03-01	04030478450000

Note: When inputting the API into the DOGGR website, input the 8 digit well API by truncating the California state code prefix (04) and excluding the trailing zeros from the 14 digit API code.

Historical Well List for Thermal Diatomite

#	Well Name	Date	API
1	TDW 34-28	2013-08-01	04030468620000
2	TDW 35-25	2013-12-01	04030468630000
3	TDW 35-27	2013-09-01	04030468520000
4	TDW 35-29	2014-01-01	04030489760000
5	TDW 36-22	2014-01-01	04030468640000
6	TDW 36-24	2013-11-01	04030468650000
7	TDW 36-26	2013-12-01	04030468340000
8	TDW 36-28	2014-01-01	04030468350000
9	TDW 37-19	2014-01-01	04030468360000
10	TDW 37-21	2014-01-01	04030468670000
11	TDW 37-23	2014-01-01	04030468680000
12	TDW 37-25	2014-01-01	04030468370000
13	TDW 37-27	2014-01-01	04030468690000
14	TDW 37-29	2013-09-01	04030468700000
15	TDW 38-14	2014-07-01	04030530280000
16	TDW 38-16	2014-07-01	04030452430000
17	TDW 38-18	2014-01-01	04030468380000
18	TDW 38-20	2014-01-01	04030468390000
19	TDW 38-22	2014-01-01	04030455480000
20	TDW 38-24	2013-12-01	04030468660000
21	TDW 38-26	2013-12-01	04030468400000
22	TDW 38-28	2013-12-01	04030468410000
23	TDW 39-15	2014-07-01	04030469360000
24	TDW 39-17	2014-01-01	04030409300000
25	TDW 39-19	2014-01-01	04030466960000
26	TDW 39-21	2014-01-01	04030468420000
27	TDW 39-23	2013-12-01	04030468710000
28	TDW 39-25	2013-12-01	04030468720000
29	TDW 39-27	2013-12-01	04030468430000
30	TDW 39-29	2013-12-01	04030468440000
31	TDW 40-16	2014-07-01	04030469380000
32	TDW 40-18	2014-01-01	04030468450000
33	TDW 40-20	2014-01-01	04030468460000
34	TDW 40-22	2014-01-01	04030467840000
35	TDW 40-24	2013-11-01	04030468730000
36	TDW 40-26	2014-01-01	04030468740000
37	TDW 40-28	2014-01-01	04030468470000
38	TDW 40-30	2013-03-01	04030467380000
39	TDW 41-17	2014-01-01	04030469410000
40	TDW 41-19	2014-01-01	04030468480000
41	TDW 41-21	2014-01-01	04030467850000
42	TDW 41-23	2014-01-01	04030467860000
43	TDW 41-25	2013-12-01	04030468750000
44	TDW 41-27	2013-12-01	04030468760000
45	TDW 41-29	2013-05-01	04030467500000
46	TDW 41-31	2014-01-01	04030467510000
47	TDW 42-18	2014-01-01	04030469420000
48	TDW 42-20	2014-01-01	04030452440000
49	TDW 42-22	2014-01-01	04030467870000
50	TDW 42-24	2014-01-01	04030466930000
51	TDW 42-26	2013-12-01	04030468770000
52	TDW 42-28	2012-10-01	04030467390000
53	TDW 42-30	2013-03-01	04030467520000
54	TDW 43-19	2014-01-01	04030469430000
55	TDW 43-21	2014-01-01	04030466940000
56	TDW 43-23	2014-01-01	04030466950000
57	TDW 43-25	2014-01-01	04030467880000
58	TDW 43-27	2013-09-01	04030467400000
59	TDW 43-29	2012-12-01	04030467410000
60	TDW 43-31	2014-01-01	04030467530000
61	TDW 44-22	2014-01-01	04030467890000
62	TDW 44-24	2014-01-01	04030467900000
63	TDW 44-26	2014-05-01	04030467910000
64	TDW 44-28	2012-11-01	04030467420000
65	TDW 44-30	2012-10-01	04030467430000
66	TDW 45-23	2014-01-01	04030467920000
67	TDW 45-25	2014-05-01	04030467930000
68	TDW 45-27	2014-05-01	04030467940000
69	TDW 45-29	2013-06-01	04030463270000
70	TDW 45-31	2013-03-01	04030467440000
71	TDW 46-22	2014-01-01	04030514260000
72	TDW 46-24	2014-05-01	04030467950000
73	TDW 46-26	2014-05-01	04030467960000
74	TDW 46-28	2014-05-01	04030467970000
75	TDW 46-30	2014-03-01	04030467450000
76	TDW 46-32	2012-10-01	04030467460000
77	TDW 47-23	2014-05-01	04030523320000
78	TDW 47-25	2014-05-01	04030523330000
79	TDW 47-27	2014-05-01	04030467980000
80	TDW 47-29	2014-05-01	04030467990000
81	TDW 47-31	2014-01-01	04030467470000
82	TDW 47-33	2012-12-01	04030467480000
83	TDW 48-24	2014-05-01	04030523340000
84	TDW 48-26	2014-05-01	04030522800000
85	TDW 48-28	2014-05-01	04030468000000
86	TDW 48-30	2014-11-01	04030468490000
87	TDW 48-32	2012-12-01	04030467490000
88	TDW 49-25	2014-05-01	04030522810000
89	TDW 49-27	2014-05-01	04030522820000
90	TDW 49-29	2014-11-01	04030530270000
91	TDW 49-31	2014-11-01	04030468500000
92	TDW 49-35	2014-11-01	04030468510000
93	TDW 50-26	2014-05-01	04030409320000
94	TDW 50-28	2014-11-01	04030530210000
95	TDW 50-30	2014-11-01	04030530250000
96	TDW 50-32	2014-11-01	04030530220000
97	TDW 50-34	2014-11-01	04030529880000
98	TDW 51-27	2015-02-01	04030546300000
99	TDW 51-29	2014-11-01	04030529890000
100	TDW 51-31	2014-11-01	04030530260000
101	TDW 51-33	2014-11-01	04030530230000
102	TDW 52-28	2015-02-01	04030431860000
103	TDW 52-32	2014-11-01	04030530240000
104	TDW 52-34	2015-02-01	04030529900000

Note: When inputting the API into the DOGGR website, input the 8 digit well API by truncating the California state code prefix (04) and excluding the trailing zeros from the 14 digit API code.

Historical Well List for Sandstone

#	Well Name	Date	API	#	Well Name	Date	API	#	Well Name	Date	API
1	21Z 09-C2	2010-04-10	04030396340000	37	21Z O-18	2012-04-12	04030434490000	73	21Z LM-22Ai	N/A	04030528910000
2	21Z 09-C3	2010-04-10	04030396350000	38	21Z O-19	2012-04-12	04030434500000	74	21Z LM-22Bi	N/A	04030528920000
3	21Z H-20	2013-01-13	04030434440000	39	21Z O-20	2012-05-12	04030434510000	75	21Z LM-23i	N/A	04030528930000
4	21Z H-21X	2014-10-14	04030545250000	40	21Z O-21	2013-02-13	04030460640000	76	21Z MN-17AI	N/A	04030491210000
5	21Z H-22X	2014-10-14	04030545260000	41	21Z O-22	2013-02-13	04030460650000	77	21Z MN-17BI	N/A	04030491220000
6	21Z H-23X	2014-10-14	04030545270000	42	21Z O-23	2013-01-13	04030462820000	78	21Z MN-18Ai	N/A	04030528230000
7	21Z H-24	2015-04-15	04030529310000	43	21Z O-24	2014-11-14	04030477350000	79	21Z MN-18Bi	N/A	04030528240000
8	21Z J-20	2012-04-12	04030432840000	44	21Z Q-19X	2015-03-15	04030547220000	80	21Z MN-19Ai	N/A	04030529180000
9	21Z J-21	2013-02-13	04030460240000	45	21Z Q-20X	2015-03-15	04030547230000	81	21Z MN-19Bi	N/A	04030529190000
10	21Z J-22	2013-02-13	04030460250000	46	21Z Q-21	2014-10-14	04030529470000	82	21Z MN-22Ai	N/A	04030528980000
11	21Z J-23	2013-02-13	04030462770000	47	21Z Q-22	2014-10-14	04030529450000	83	21Z MN-22Bi	N/A	04030528990000
12	21Z J-24	2015-03-15	04030529340000	48	21Z Q-23	2014-10-14	04030530730000	84	21Z MN-23Ai	N/A	04030529000000
13	21Z K-20	2012-04-12	04030434190000	49	21Z Q-24	2015-03-15	04030529460000	85	21Z MN-23Bi	N/A	04030529010000
14	21Z K-21	2013-02-13	04030460300000	50	21Z HJ-20AI	N/A	04030547440000	86	21Z NO-18Ai	N/A	04030528250000
15	21Z K-22	2013-02-13	04030460320000	51	21Z HJ-20BI	N/A	04030547450000	87	21Z NO-18Bi	N/A	04030528260000
16	21Z K-23	2013-02-13	04030462780000	52	21Z HJ-21i	N/A	04030528170000	88	21Z NO-19Ai	N/A	04030528270000
17	21Z K-24	2015-03-15	04030529320000	53	21Z HJ-22i	N/A	04030528180000	89	21Z NO-19Bi	N/A	04030528280000
18	21Z L-19	2012-04-12	04030433760000	54	21Z HJ-23i	N/A	04030528190000	90	21Z NO-20Ai	N/A	04030528290000
19	21Z L-21	2013-02-13	04030460400000	55	21Z JK-18AI-C	N/A	04029527460000	91	21Z NO-20Bi	N/A	04030528300000
20	21Z L-22	2013-02-13	04030460410000	56	21Z JK-18BI	N/A	04030486140000	92	21Z NO-21Ai	N/A	04030529020000
21	21Z L-23	2013-02-13	04030462790000	57	21Z JK-19AI-C	N/A	04029552560000	93	21Z NO-21Bi	N/A	04030529030000
22	21Z L-24	2015-03-15	04030529330000	58	21Z JK-19BI	N/A	04030491100000	94	21Z NO-22Ai	N/A	04030529040000
23	21Z M-17	2012-05-12	04030434110000	59	21Z JK-20Ai	N/A	04030527870000	95	21Z NO-22Bi	N/A	04030529050000
24	21Z M-19	2012-05-12	04030434130000	60	21Z JK-20Bi	N/A	04030527880000	96	21Z NO-23Ai	N/A	04030529060000
25	21Z M-20	2012-04-12	04030434140000	61	21Z JK-21i	N/A	04030527890000	97	21Z NO-23Bi	N/A	04030529070000
26	21Z M-21	2013-02-13	04030460480000	62	21Z JK-22i	N/A	04030528200000	98	21Z OQ-19Ai	N/A	04030531910000
27	21Z M-22	2013-02-13	04030460500000	63	21Z JK-23i	N/A	04030528830000	99	21Z OQ-19Bi	N/A	04030531920000
28	21Z M-23	2013-03-13	04030462800000	64	21Z KL-21i	N/A	04030528860000	100	21Z OQ-20Ai	N/A	04030528310000
29	21Z M-24	2015-03-15	04030529480000	65	21Z KL-22i	N/A	04030528870000	101	21Z OQ-20Bi	N/A	04030528320000
30	21Z N-18	2012-04-12	04030433830000	66	21Z KL-23i	N/A	04030528880000	102	21Z OQ-21Ai	N/A	04030529080000
31	21Z N-19	2012-04-12	04030433840000	67	21Z LM-17AI	N/A	04030486200000	103	21Z OQ-21Bi	N/A	04030529090000
32	21Z N-20	2012-04-12	04030433850000	68	21Z LM-17BI	N/A	04030486210000	104	21Z OQ-22Ai	N/A	04030529100000
33	21Z N-21	2013-01-13	04030460590000	69	21Z LM-18Ai	N/A	04030486220000	105	21Z OQ-22Bi	N/A	04030529110000
34	21Z N-22	2013-01-13	04030460600000	70	21Z LM-18Bi	N/A	04030486230000	106	21Z OQ-23Ai	N/A	04030529120000
35	21Z N-23	2013-01-13	04030462810000	71	21Z LM-21Ai	N/A	04030528890000	107	21Z OQ-23Bi	N/A	04030529130000
36	21Z N-24	2014-10-14	04030477340000	72	21Z LM-21Bi	N/A	04030528900000				

Note: When inputting the API into the DOGGR website, input the 8 digit well API by truncating the California state code prefix (04) and excluding the trailing zeros from the 14 digit API code.

Reconciliation for Adjusted EBITDA Hedged and Unhedged

($ in thousands)	Three Months Ended March 31, 2018	Ten Months Ended December 31, 2017
Net income (loss)	$ 6,410	$(21,068)
(+) Depreciation, depletion, amortization and accretion	18,429	68,478
(+) Interest expense	7,796	18,454
(+) Income tax expense (benefit)	939	2,803
(+) Derivative (gain) loss	34,644	66,900
(+/-) Net cash received (paid) for derivative settlements	(17,849)	3,068
(-) Gain on sale of assets and other	-	(22,930)
(+) Stock compensation expense	1,042	1,851
(+) Restructuring costs	2,047	30,325
(+/-) Reorganization items, net	(8,955)	1,732
Adjusted EBITDA	$ 44,503	$ 149,613
(+/-) Net cash received (paid) for derivative settlements	17,849	(3,068)
Adjusted EBITDA Unhedged	$ 62,352	$ 146,545

Note: Please see slide 2 for a note regarding the non-GAAP measures Adjusted EBITDA and Adjusted EBITDA Unhedged.

Reconciliation for Adjusted EBITDA less Capital Expenditures

($ in thousands)	Three Months Ended March 31, 2018	Ten Months Ended December 31, 2017
Net cash provided by operating activities	$ 27,592	$ 107,399
(+) Cash Interest Payments	2,654	14,276
(+) Cash income tax payments	-	1,994
(+) Cash reorganization item payments	468	1,732
(+) Restructuring costs	2,047	30,325
(+/-) Other Changes in Operating Assets and Liabilities	11,742	(6,113)
(+) Other, net	-	-
Adjusted EBITDA	$ 44,503	$ 149,613
(-) Capital Expenditures	(19,876)	(65,479)
Adjusted EBITDA less Capital Expenditures	$ 24,627	$ 84,134

Note: Please see slide 2 for a note regarding the non-GAAP measures Adjusted EBITDA and Adjusted EBITDA less Capital Expenditures.

Reconciliation for Adjusted G&A Expenses

($ in thousands)	Three Months Ended March 31, 2018	Ten Months Ended December 31, 2017
General and administrative expenses	$ 11,985	$ 56,009
(-) Non-recurring restructuring and other costs	(2,047)	(30,325)
(-) Non-cash stock compensation expense	(1,019)	(1,819)
Adjusted G&A Expenses	$ 8,919	$ 23,865

Note: Please see slide 2 for a note regarding the non-GAAP measure Adjusted G&A Expenses.

Proved Reserves as of December 31, 2017
SEC and Strip Prices

	Proved Reserves and PV-10[1] as of December 31, 2017 (SEC Pricing)[2]						Proved Reserves and PV-10[1] as of December 31, 2017 (Strip Pricing)[3]					
	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% of Proved	PV-10 ($mm)	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% of Proved	PV-10 ($mm)
PDP	63	100	1	81	57%	$762	64	67	1	77	67%	$1,205
PDNP	6	-	-	6	4%	$89	6	-	-	6	5%	$136
PUDs[4]	32	137	-	55	39%	$262	32	-	-	32	28%	$521
Total	**101**	**237**	**1**	**141**	**100%**	**$1,114**	**102**	**67**	**1**	**115**	**100%**	**$1,862**

[1] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.| [2] Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX Henry Hub for natural gas at December 31, 2017. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. | [3] Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX Henry Hub for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. The volume-weighted average 26 prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.94 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. | [4] Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude the development in the Piceance basin.

Proved Reserves as of December 31, 2017
SEC and Strip Prices (Cont.)

	Proved Reserves as of December 31, 2017 (SEC Pricing)[1]					Proved Reserves as of December 31, 2017 (Strip Pricing)[2]				
	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin	Total	San Joaquin and Ventura basins	Uinta basin	Piceance basin	East Texas basin	Total
Proved developed reserves:										
Oil (MMBbl)	61	7	-	-	68	63	7	-	-	70
Natural Gas (Bcf)	-	47	42	12	100	-	41	17	9	67
NGLs (MMBbl)	-	1	-	-	1	-	1	-	-	1
Total (MMBoe)[3, 4]	61	16	7	2	86	63	15	3	2	82
Proved undeveloped reserves[5]:										
Oil (MMBbl)	32	-	-	-	32	32	-	-	-	32
Natural Gas (Bcf)	-	-	137	-	137	-	-	-	-	-
NGLs (MMBbl)	-	-	-	-	-	-	-	-	-	-
Total (MMBoe)[4]	32	-	23	-	55	32	-	-	-	32
Total proved reserves:										
Oil (MMBbl)	93	7	-	-	101	95	7	-	-	102
Natural Gas (Bcf)	-	47	179	12	237	-	41	17	9	67
NGLs (MMBbl)	-	1	-	-	1	-	1	-	-	1
Total (MMBoe)[4]	93	16	30	2	141	95	15	3	2	115

[1] Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $54.42 per Bbl ICE (Brent) for oil and NGLs and $2.98 per MMBtu NYMEX Henry Hub for natural gas at December 31, 2017. The volume-weighted average prices over the lives of the properties were $48.20 per barrel of oil and condensate, $28.25 per barrel of NGL and $2.935 per thousand cubic feet of gas. The prices were held constant for the lives of the properties, and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. | [2] Our Strip Pricing reserves were prepared on the same basis as our SEC reserves and do not include changes to costs, other economic parameters, well performance or drilling activity subsequent to December 31, 2017, except for the use of pricing based on closing month futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX Henry Hub for natural gas on May 31, 2018 rather than using the average of the first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Our Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining our Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. The volume-weighted average 26 prices over the lives of the properties were $61.67 per barrel of oil and condensate, $19.49 per barrel of NGL, and $1.94 per thousand cubic feet of gas. We have taken into account pricing differentials reflective of the market environment, and NGL pricing used in determining our Strip Pricing reserves was approximately ICE (Brent) for oil less $49.00. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of oil and natural gas prices as of a certain date. Strip Pricing futures prices are not necessarily an accurate projection of future oil and gas prices. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC prices, when considering our oil and natural gas reserves. | [3] Approximately 9% of proved developed oil reserves, 0% of proved developed NGLs reserves, 0% of proved developed natural gas reserves and 7% of total proved developed reserves are non-producing. | [4] Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2017, the average prices of ICE (Brent) oil and NYMEX Henry Hub natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1. | [5] Using SEC Pricing as of December 31, 2017, there were approximately 23 MMBoe of PUDs associated with projects in the Piceance basin. Subsequent to year end, as a result of increasingly negative local gas pricing differentials, we revised our current development plan to exclude these Piceance locations.