Berry Technical 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 33-34.

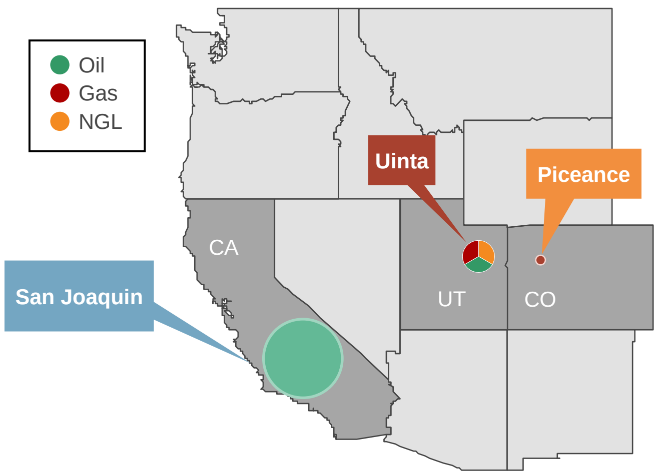
Berry uses PV-10, a supplemental financial measure that is not presented in accordance with U.S. generally accepted accounting principles ("GAAP"), in this presentation, which reflects the present value of its estimated future net revenues to be generated from the production of proved reserves, determined 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.

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 31-33 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.

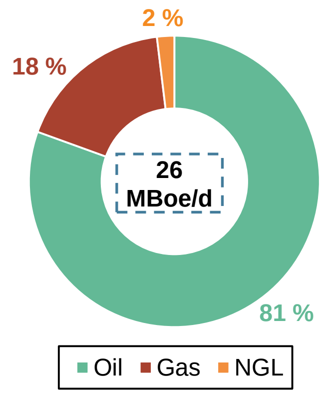
Berry Petroleum: A U.S. Onshore Conventional *Oil* Company

- 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

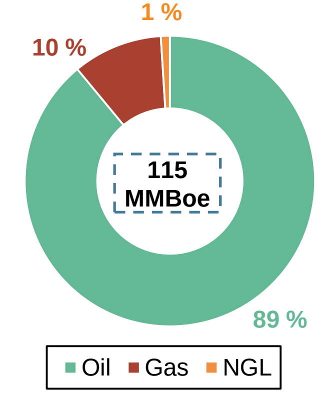
Map of Berry Assets[1,2]



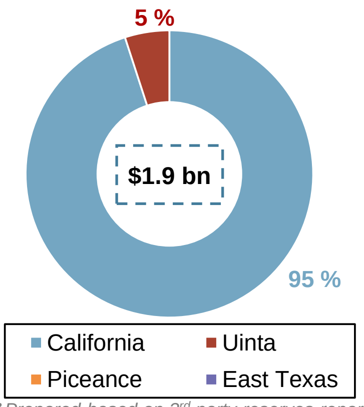
1Q18 Production by Commodity[3]



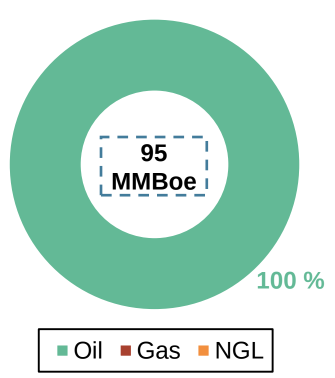
1P Reserves by Commodity[2]



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 slide 33-34. | [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.

Berry's Completion and Recovery Mechanisms

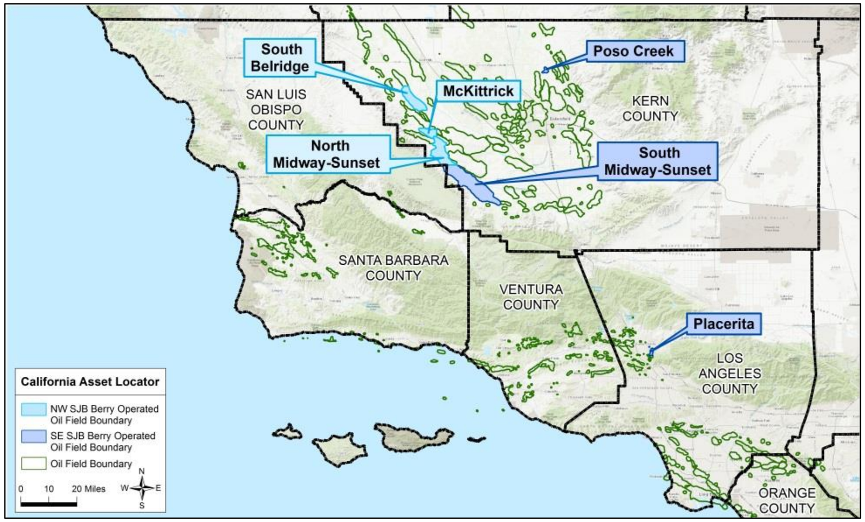
State	Project Type	Well Type	Completion Type	Recovery Mechanism	Depth (ft.)
California	Hill Diatomite (non-thermal)	Vertical	Low intensity pin point fracture stimulation	Pressure Depletion augmented with water injection	1,300 – 2,000
	Thermal Diatomite	Vertical	Short interval perforations (dual completions)	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

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



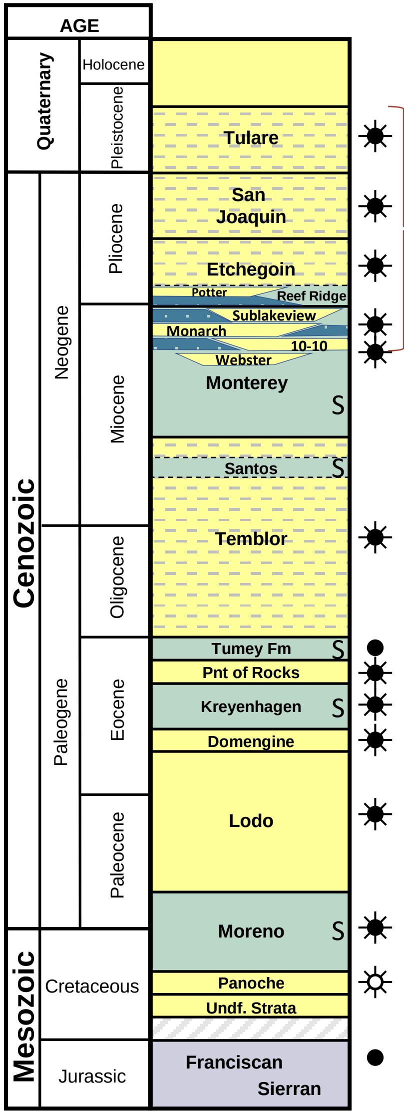
Note: Prepared based on 3rd party reserves report addendum as of June 28, 2018 and closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. For a comparison to SEC Pricing, please see slides 33-34. | [1] Please see slide 2 for 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.

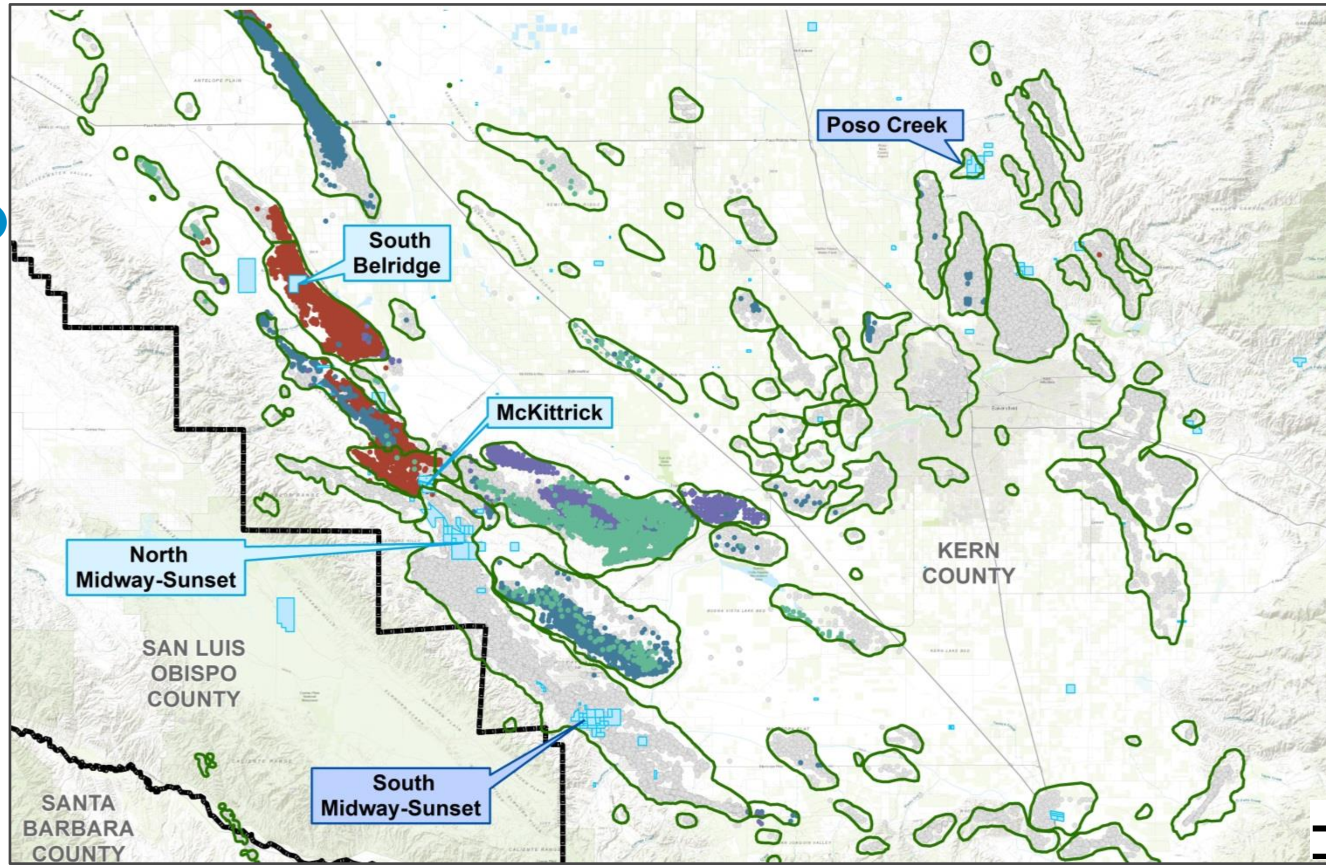
- Drilling opportunities exist in each asset area allowing for production growth and increased recovery and reserves
  - Prolific history of results allow for predictable results
  - Low D&C costs and quick spud to production times enhance execution of development plans
- Existing infrastructure in place 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



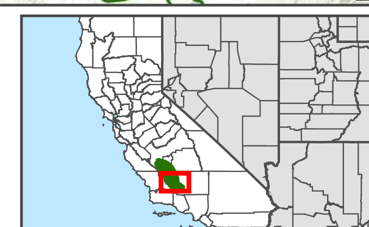


Berry Producing Intervals
Gas & Oil Production
Gas Production
Oil Production
S Source Rock

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



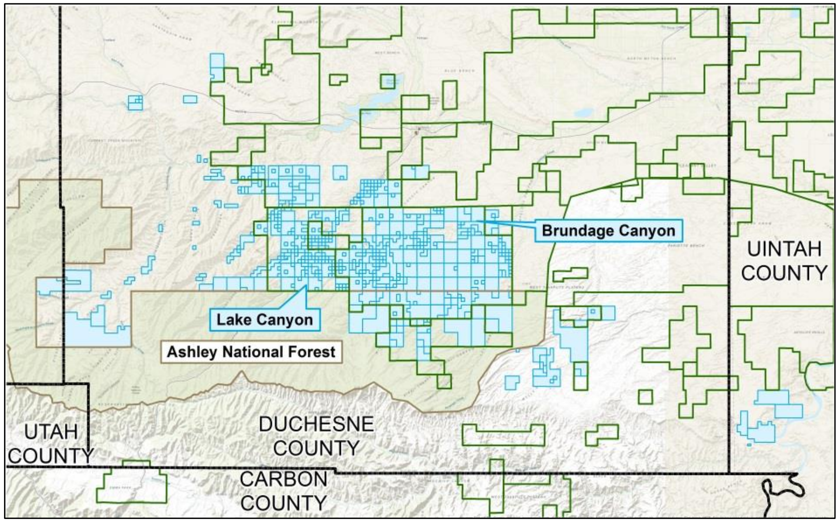
Utah – Uinta Basin

Asset Overview

- Uinta is defined by multiple stack oil field reservoirs with tremendous undeveloped resources remaining
  - 2,000 feet of stacked oil pay in the Green River and Wasatch formations
- Proved reserves of 15 MMBoe and Proved PV-10[1] of $91mm (5/31 Strip Pricing)
- Strategies for this asset include:
  - Refine our reservoir management plan to incorporate the 1,245 potential additional drilling opportunities on Berry acreage
  - Determine best use of horizontal technology in certain reservoirs
    - Recent results from offset operators are encouraging and as those results continue to support the investment, Berry will be a "fast follower" in 2018 by drilling horizontal locations
  - Large opportunity to move probable and possible reserves into proved categories with strategic investments
  - Continually advance cost controls for high margin returns
  - Continue successful recompletion and workover programs to maintain a strong low decline base production profile
  - Take advantage of extensive infrastructure and available takeaway capacity in place to support additional development
- 72% Held By Production

Source: Utah Department of Natural Resources
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 33-34. | [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.

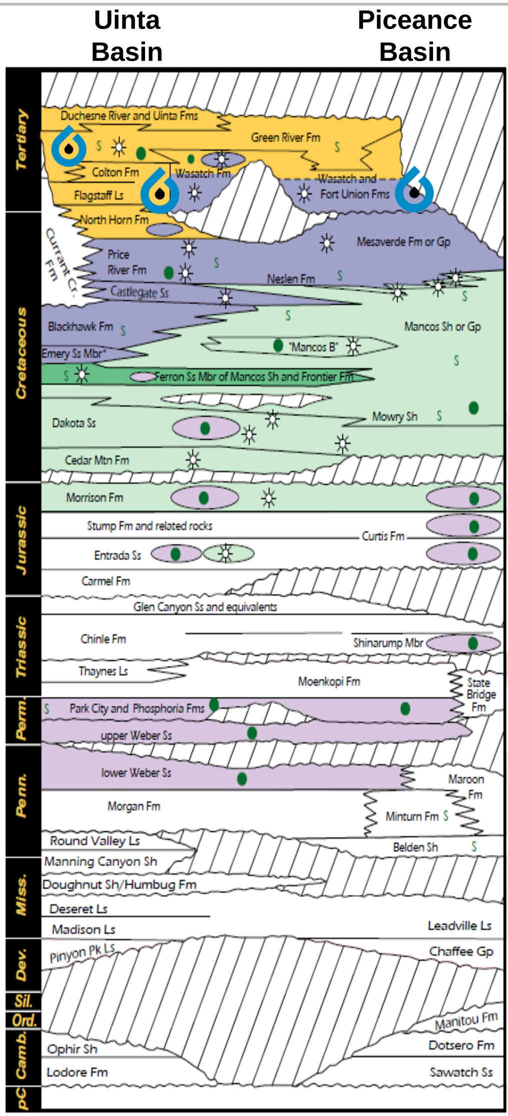
Map of Operations

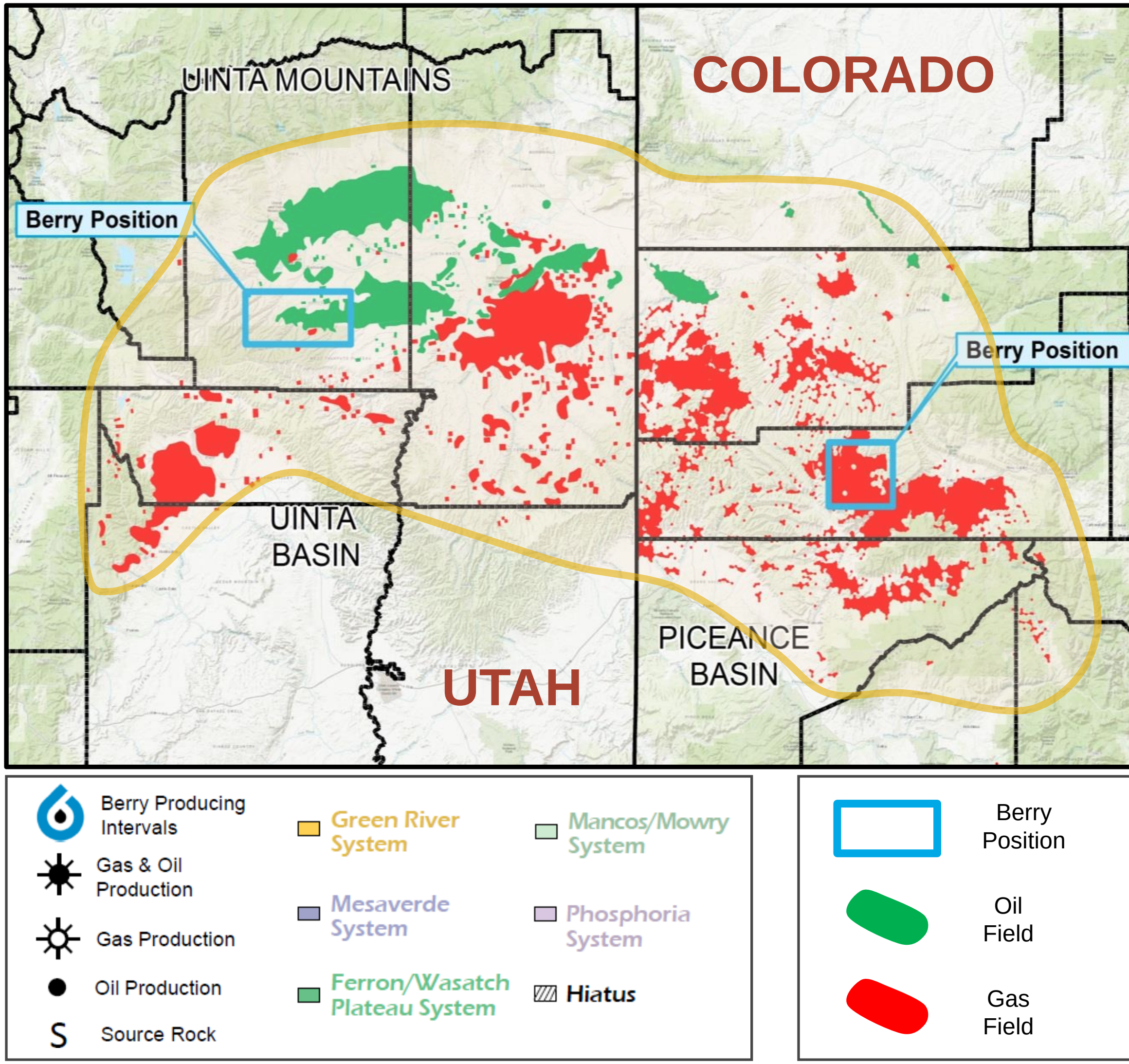


Asset Description

Uinta	
Net Acreage	96,096
Core Areas	Brundage Canyon, Ashley Forest, Lake Canyon
Q1 2018 Net Production (Mboe/d)	5
Average WI / NRI[2]	95 % / 62 %
Producing Wells, Gross	909

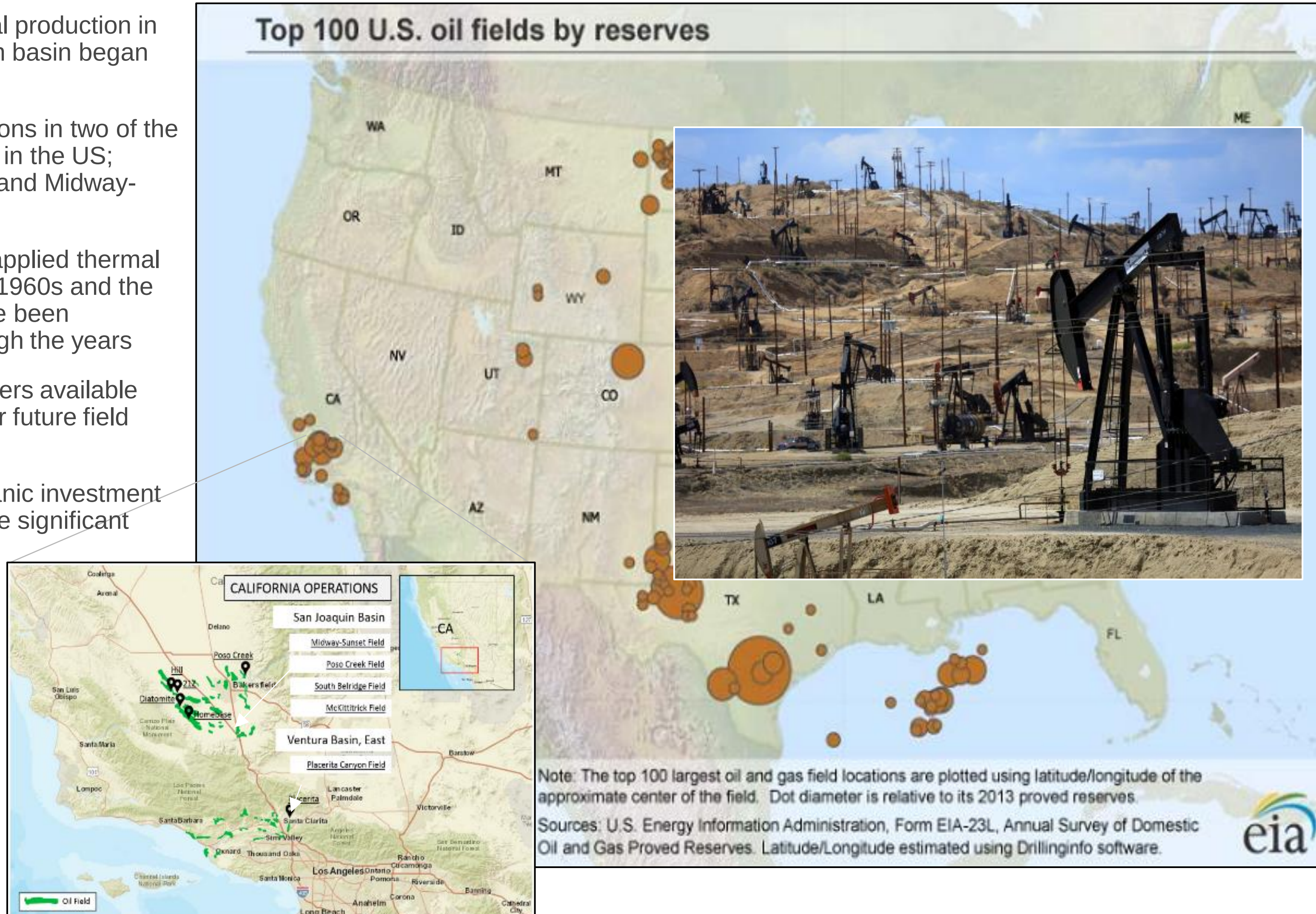
Greater Uinta – Piceance Basin and Petroleum Systems





Most Berry CA Assets Located in San Joaquin "Super Basin"

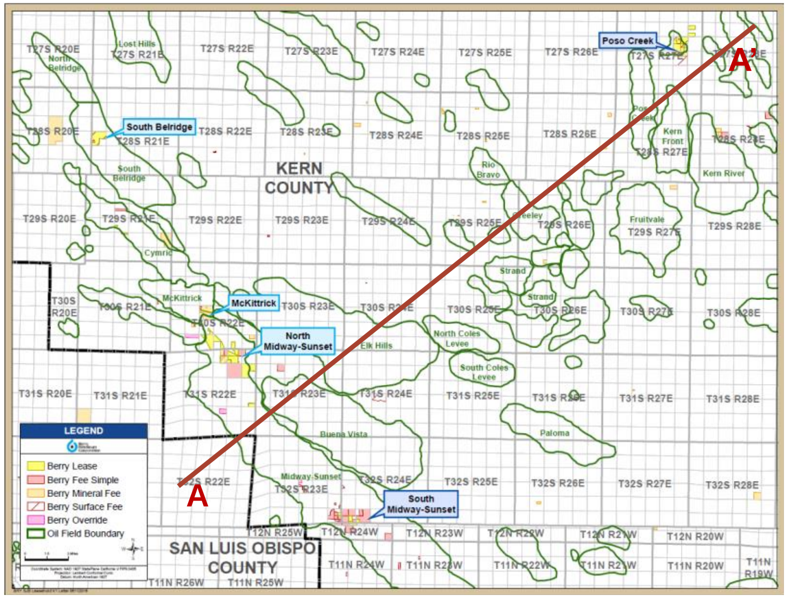
- First commercial production in the San Joaquin basin began back in 1887
- Berry has positions in two of the largest oil fields in the US; South Belridge and Midway-Sunset
- Operators first applied thermal recovery in the 1960s and the techniques have been optimized through the years
- San Joaquin offers available infrastructure for future field development
- Remaining organic investment opportunities are significant

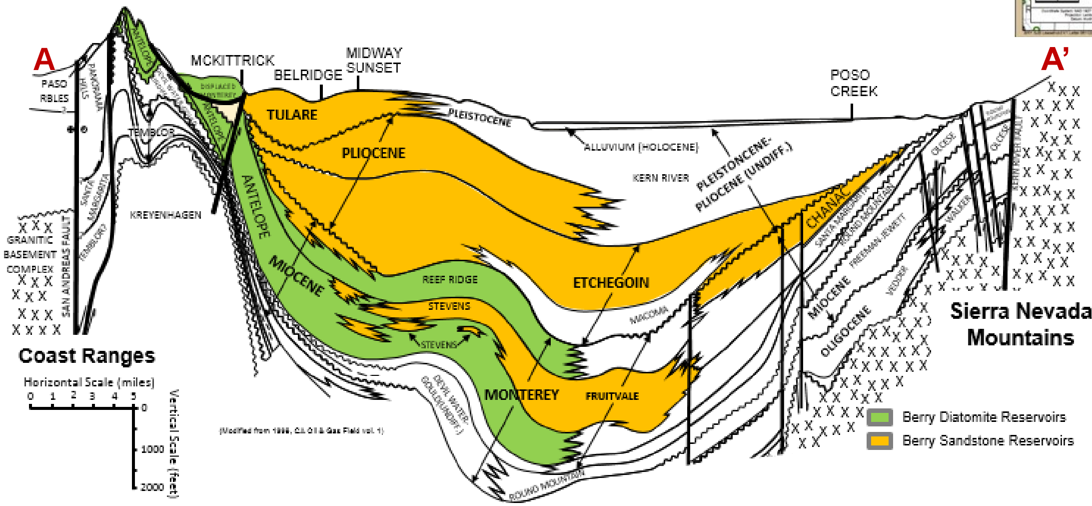


Source: EIA

California – San Joaquin Basin – Geologic Overview

- The San Joaquin Basin is located ~ 70 miles north of Los Angeles
- San Joaquin Basin is bounded to the east by the Sierra Nevada Mountains, to the west by the California Coast Ranges, and to the south by the Transverse Ranges
- First oil production in 1887
- 4 of the largest continental U.S. oil fields are located in San Joaquin Basin and Berry has producing positions in two of them
  - **South Belridge**, **Midway-Sunset**, Kern River, Elk Hills
- Trapping mechanisms include a combination of stratigraphic, tar seals, structural, and up-dip truncation at unconformities





Colored formations are reservoirs Berry produces from

Source: USGS, DOGGR, California Department of Conservation

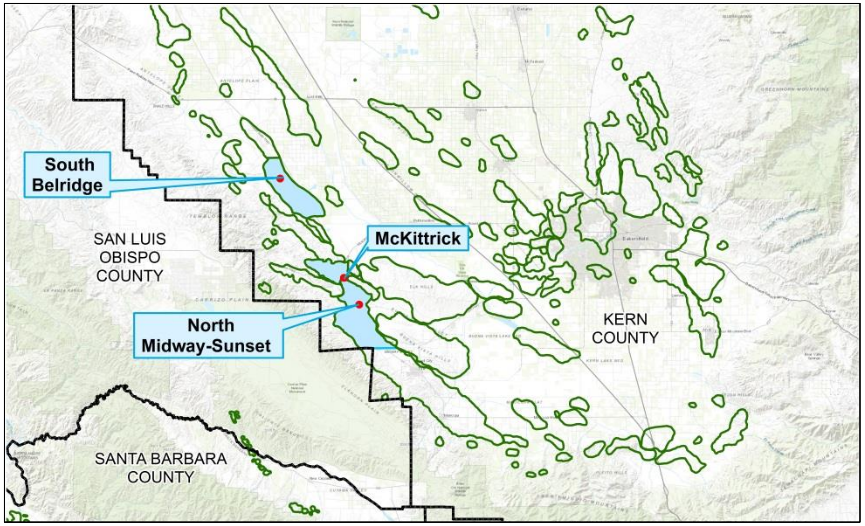
California – Northwest San Joaquin Asset

Asset Overview

- The Northwest San Joaquin asset produces from the Midway-Sunset, South Belridge and McKittrick Fields
- Proved reserves of 50 MMBoe and Proved PV-10[1] of $1,010mm (5/31 Strip Pricing)
- The development of this asset is less mature than other assets in California
- Strategies for this asset include:
  - Continue development in each area increasing value and reserves by drilling highly repeatable low costs producers and injectors and expanding reservoir boundaries
  - Large opportunity to move probable and possible reserves into proved categories with strategic investments
  - Continually advance cost controls for high margin returns
  - Use advanced proven technology and recovery techniques to unlock value in the diatomite reservoirs
    - The opportunity in the thermal Diatomite reservoir is vast and predicated on execution of advanced thermal recovery techniques
    - Advanced fracturing techniques will raise recoveries in the non-thermal South Belridge diatomite reservoir

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 33-34. | [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.

Map of Operations



Asset Description

Northwest San Joaquin	
Net Acreage	3,302
Core Areas	South Belridge, McKittrick, Midway-Sunset
Q1 2018 Net Production (Mboe/d)	9
Average WI / NRI[2]	100 % / 98 %
Producing Wells, Gross	1,336

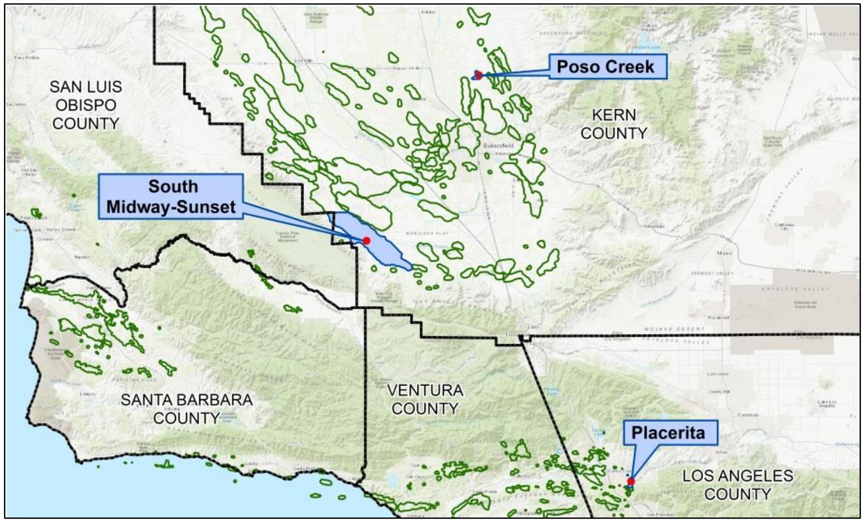
California – Southeast San Joaquin Asset

Asset Overview

- Southeast San Joaquin is currently Berry's largest producing California asset area with production from Midway-Sunset, Poso Creek and Placerita Fields
- Proved reserves of 46 MMBoe and Proved PV-10[1] of $750mm (5/31 Strip Pricing)
- Strategies for this asset include:
  - Maintain a strong production base by drilling highly repeatable, low decline reliable thermal horizontal and vertical wells
  - Push proven technology and recovery techniques to unlock higher recovery of the large available oil in place
  - Continually advance cost controls for high margin returns
  - Move probable and possible reserves into proved categories with strategic investments
- A representative example of the effectiveness of the use of advanced technology and innovation in this prolific basin is the Ethel D lease located in the Midway-Sunset Field. This lease reached peak production of ~2.9 Mboe/d in recent years after over 100 years of production

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 33-34. | [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.

Map of Operations

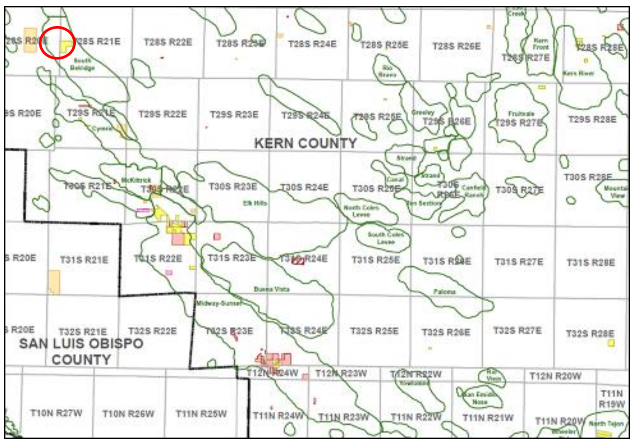


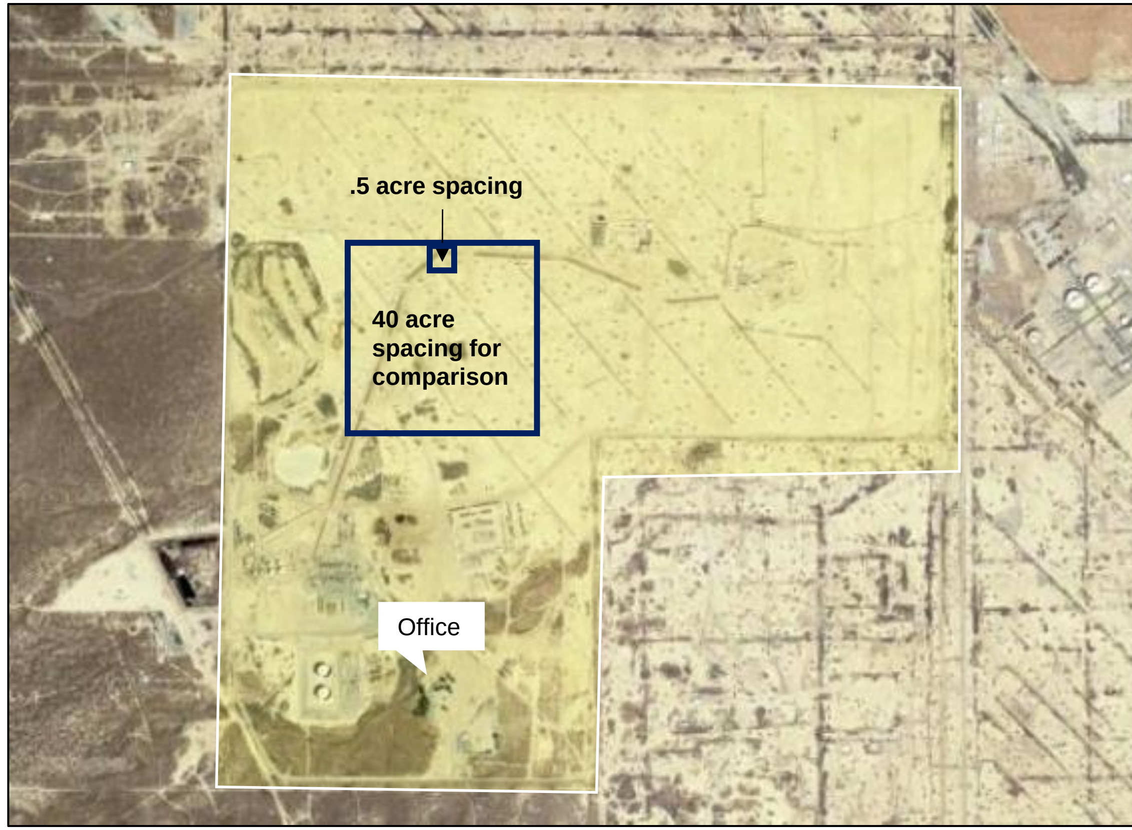
Asset Description

Southeast San Joaquin	
Net Acreage	4,643
Core Areas	Ethel D, Placerita, Poso Creek, S. Midway
Q1 2018 Net Production (Mboe/d)	10
Average WI / NRI[2]	98 % / 93 %
Producing Wells, Gross	1,264

South Belridge – Hill Lease

- 502 acres
- Acquired remaining interest in July '17





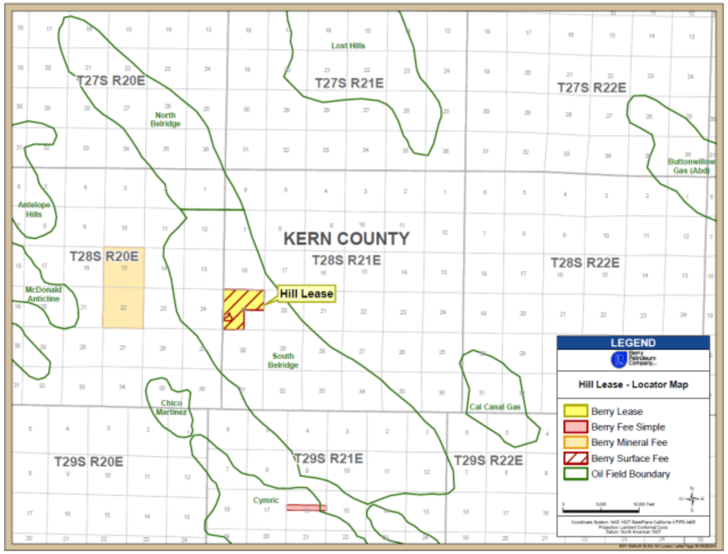
Taking Strategic Action to Narrow Focus and Consolidate Scale

In July 2017, Berry acquired Linn's ~84% working interest in the South Belridge Hill lease and sold its non-operated ~78% working interest in the Hugoton asset

Transaction Rationale

- Enhances size, scale and positioning in a core California asset with material upside
- Exit of a mature and non-core region, with aging infrastructure
- Production profile is now overwhelmingly oil (58% oil prior to restructuring to 81% oil today[1])
- Narrows focus, allowing for greater allocation of resource towards operational enhancements

South Belridge Hill – Location Map

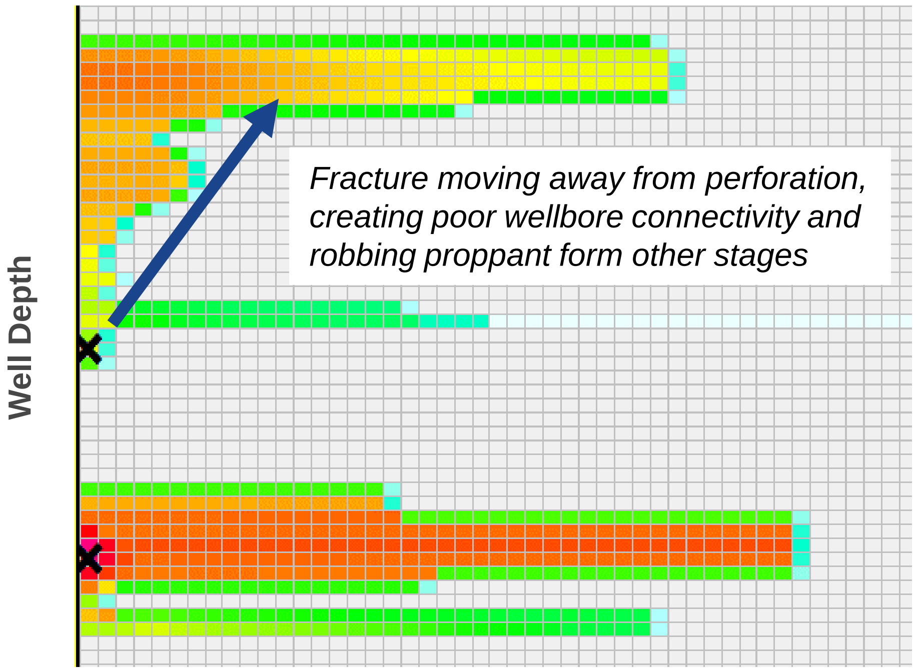


	Hill Acquisition	Hugoton Disposition
Ownership Type	**Operated**	**Non-Operated**
Berry's Portfolio	**Core**	**Non-Core**

[1] Commodity mix prior to restructuring refers to FY 2016 production (prior to Hill acquisition / Hugoton disposition). Today's commodity mix refers to 1Q 2018 production.

South Belridge – Hill Lease – Pin Point Hydraulic Fracturing

Plug and Perforate Fracture Model



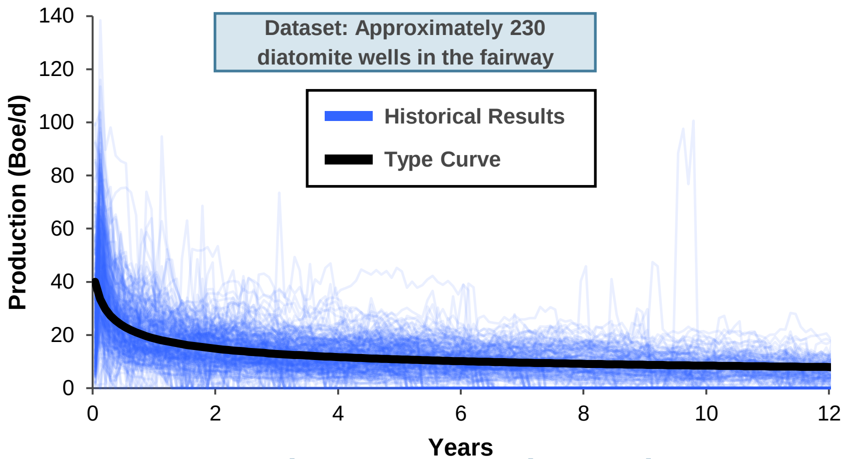
Fracture Length
(brighter color indicates more proppant)

Shift to Pin Point Fracturing

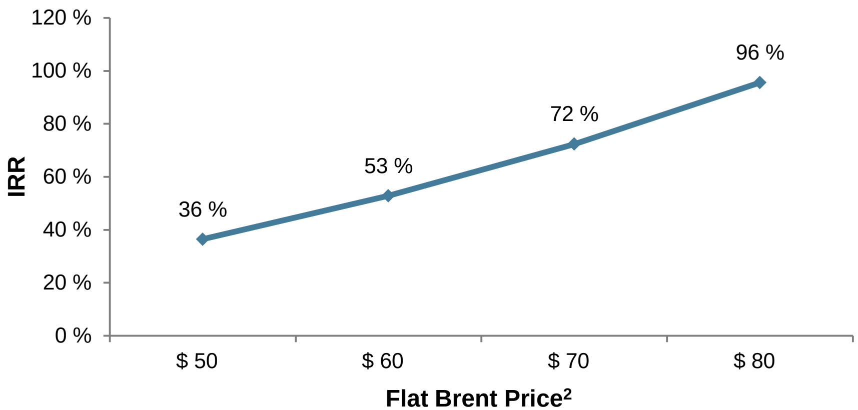
- Traditional plug and perforate hydraulic fracturing attempts to stimulate a large area at once
- Downhole tiltmeter data has confirmed that the reservoir has "thief" zones that rob some perforations of proppant
- Modeling has reproduced this phenomena and correlated it to measurable reservoir properties
- Pin point hydraulic fracturing can stimulate the same area, but by using smaller, select stages
  - Greater precision allows targeted stimulation by reservoir properties
  - Proppant being split between more stages mitigates the impact of any possible "thief" zone

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 (Tier 1 / Total)	311 / 896
WI / NRI	100 % / 100 %

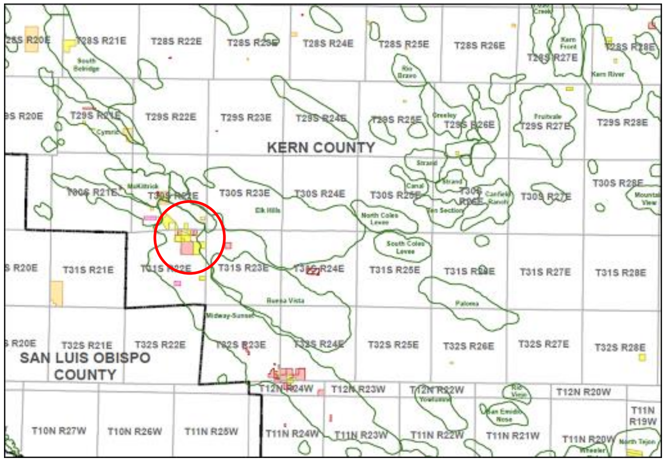
Aggregate Pattern Type Curve Assumptions and Results

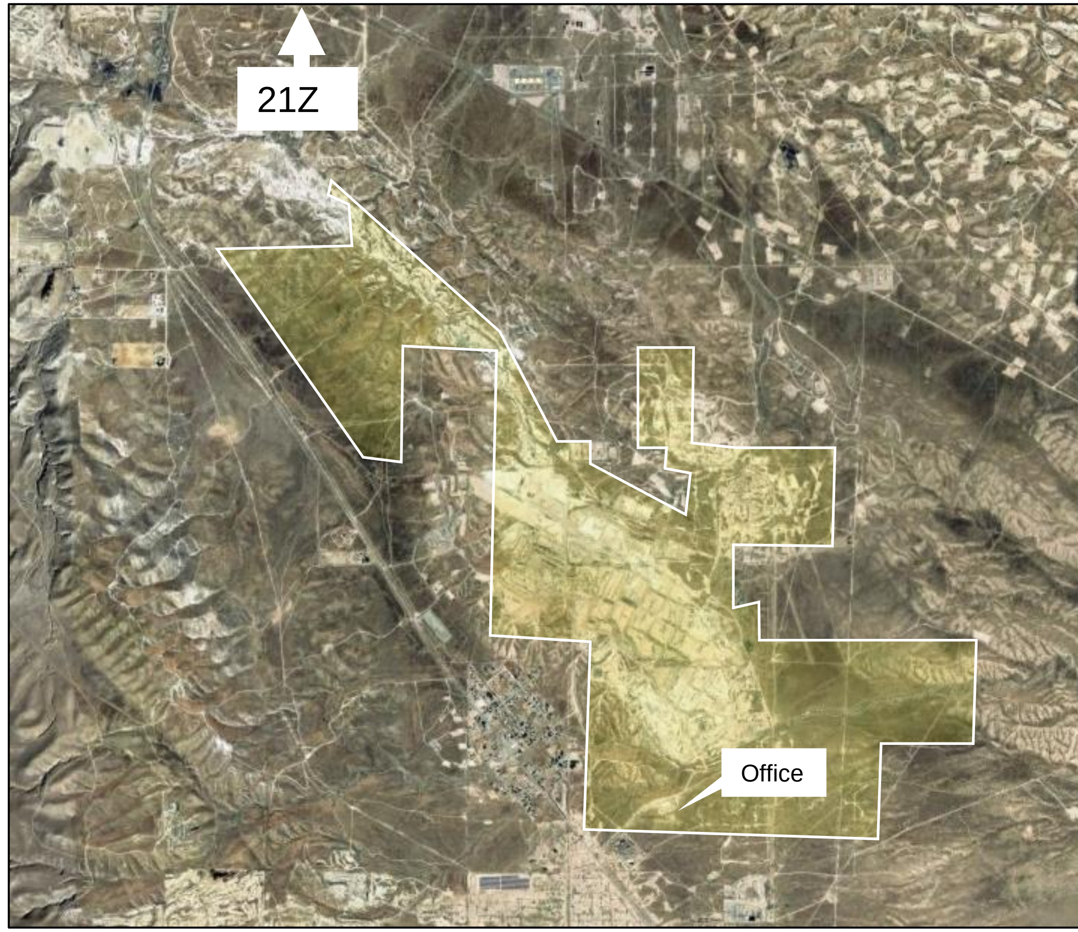
Gross Capex ($mm / pattern)	$ 2.2
Net EUR (Mboe)	139
% Oil	100 %
IP90 Production (Boe/d)	94.8
Brent Differential ($/Bbl)	$ 1.13
Fixed Opex per pattern ($k/month)	$ 4.94
Variable Opex[3] per boe ($/Boe)	$ 1.68
Steam[3] ($/Boe)	-
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[4] as of May 31, 2018	78 %
PV-10[5] ($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] 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] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10.

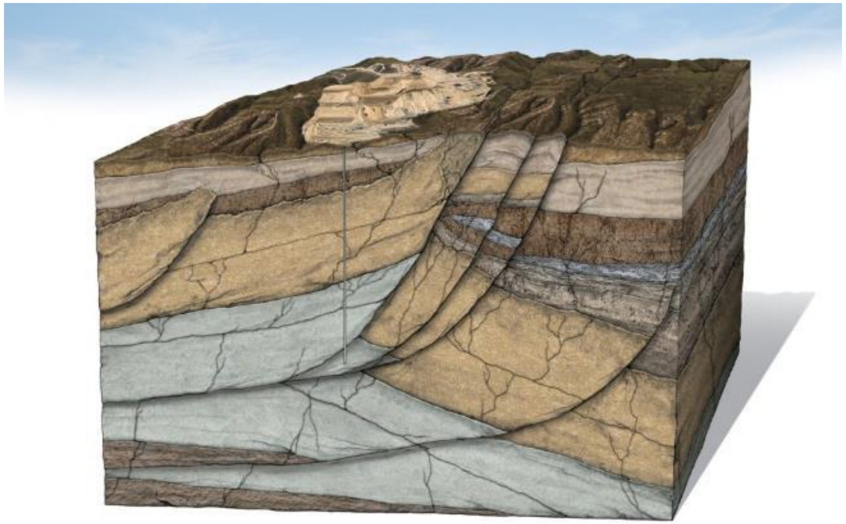
North Midway-Sunset – Diatomite

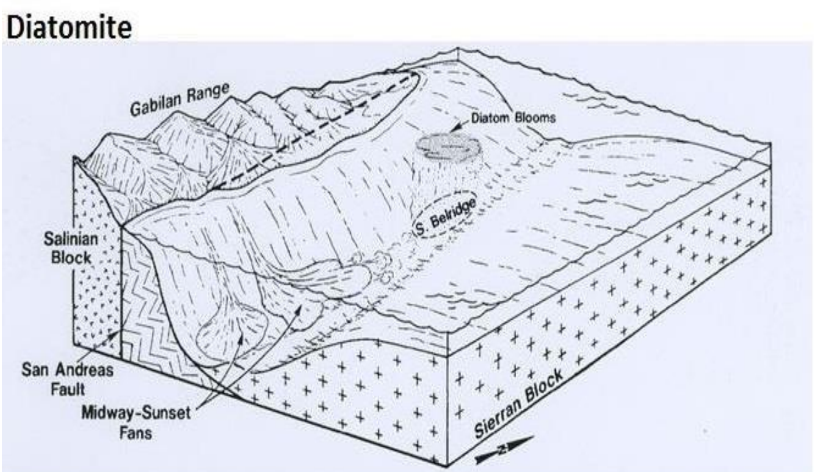
- 2,640 acres
- Recent acreage adds





Thermal Diatomite Geologic Overview
Reservoir Properties





- Thick pay (+/- 400')
- Very high porosity
  - Opal A:55-75%
  - Opal CT: 40-55%
- Poor permeability
  - Matrix <5 mD
- Highly compressible
  - Production depletes fluids
  - Causes compaction and subsidence
- High oil saturation
  - 30-95% in producible intervals
- Highly faulted and fractured
  - Greater deformation near McKittrick Fault
  - Overturned and faulted folds common
- Heavy oil (13° API)
  - Produced from fractures both natural and induced
  - Higher perm zones (bitumen zones etc.) depleted of oil can serve as steam thief zones

Source: Internal Well Information on Berry Properties

Diatomite Recovery Fundamentals
Summary of Key Recovery Components

Permeability Enhancement (↑k)

- Diatomite matrix has essentially no natural permeability (0.5-5md) and requires fracturing to provide flow paths to and from the reservoir

Viscosity Reduction (↓μ)

- Heavy oil requires viscosity reduction to flow

Imbibition (↑I)

- Primary mechanism responsible for oil flow from matrix
- Enhanced by temperature increase and viscosity reduction

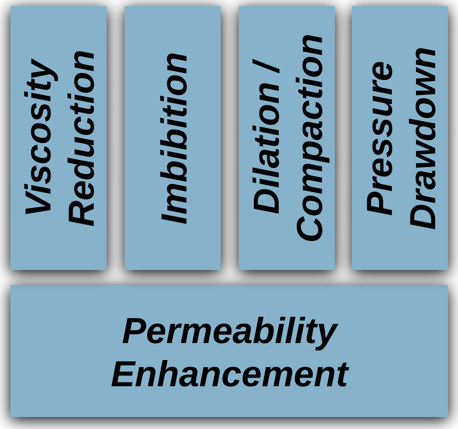
Dilation/Compaction with Net Dilation (↑ΔP)

- Initial pressurization of the reservoir (net dilation) is required to induce fluid flow to surface
- Each steam cycle diatomite undergoes dilation (injection) and compaction (production) acting as an efficient energy storage containment mechanism, providing drive energy to induce flowback to surface

Regulated Pressure Drawdown (↑ΔP, ↑ r_w)

- Back-pressure must be applied to control efficient release of energy from the reservoir (↑ΔP) and prolong fracture connectivity with wellbore (↑ r_w)

Recovery Fundamentals Hierarchy

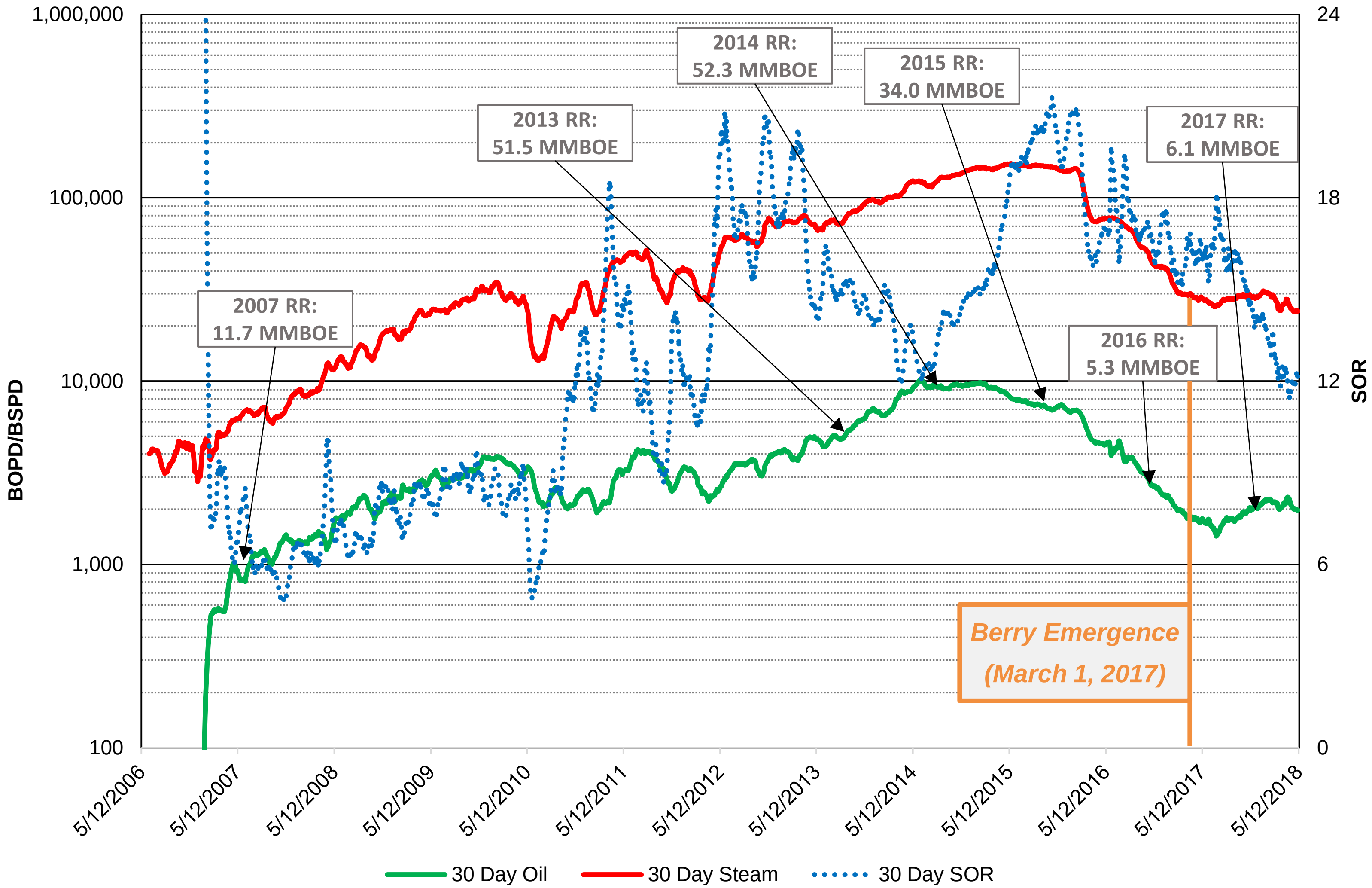


Modified Darcy's Law: Radial Flow

$$q = \frac{2\pi k h \Delta P}{\mu \ln\left(\frac{r_e}{r_w}\right)} \times I$$

Thermal Diatomite Recovery Process

Thermal Diatomite History

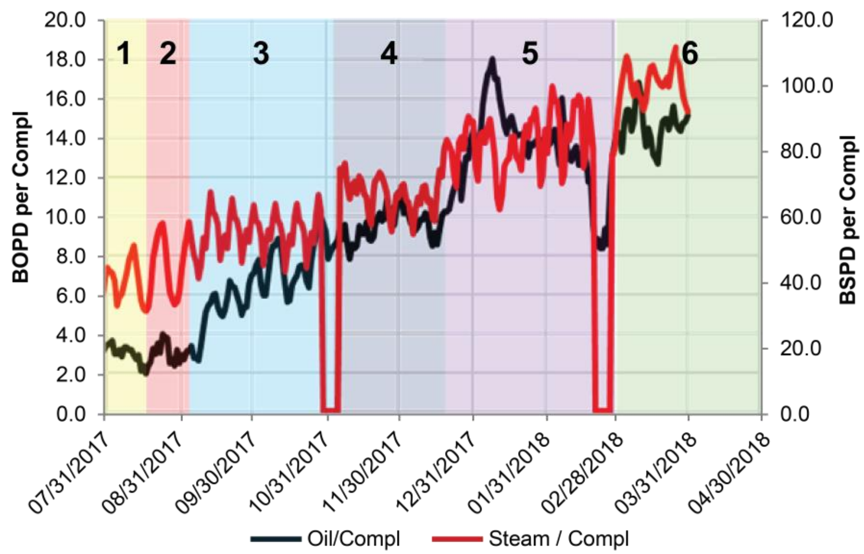


[1] Reserve information prepared based on 3rd party reserve reports.

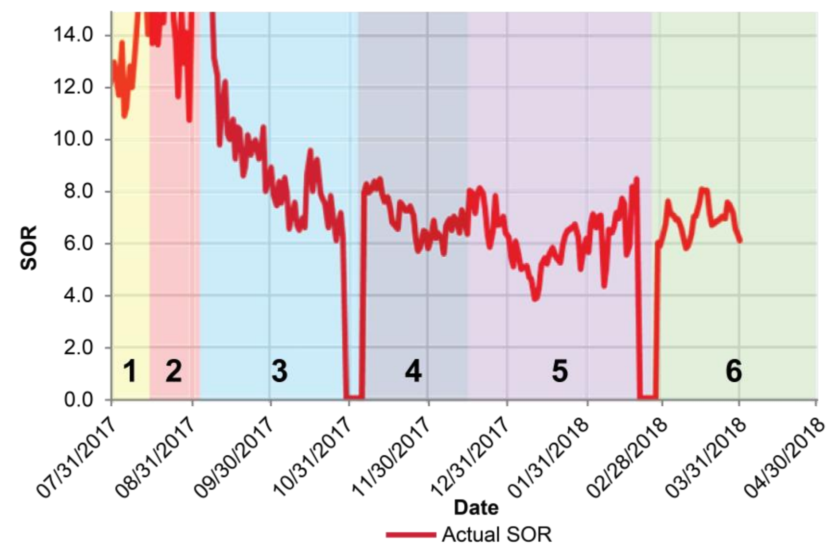
Thermal Diatomite Recovery Process

Belgian Header 7 Steaming Strategies

BG HDR 7 Production per Compl



BG HDR 7 SOR per Compl

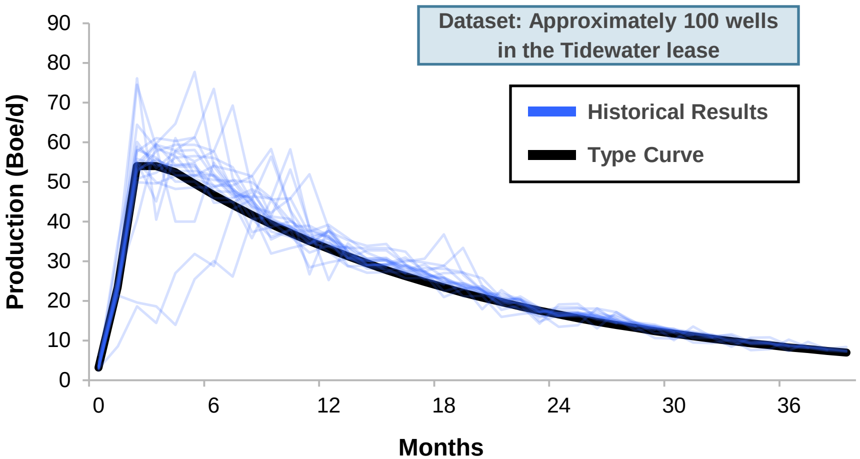


- Process change resulting in better overall SOR and ultimate value
- Increasing cycle size through early time
- Focus on total volumes over injection rate

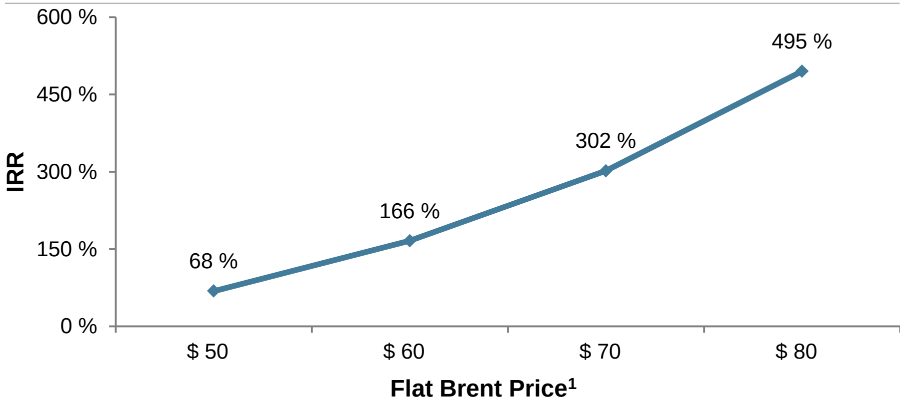
Stage	BSPD* Top Perf	Days btw Cycle	Cycle Days	~Vol per Cycle	Date Range
1	0.5	8.9	1.5	375	7/20/2017 - 8/10/2017
2	0.5	8.9	2.0	500	8/10/2017 - 9/5/2017
3	0.75	8.8	1.3	550	9/5/2017 - 11/1/2017
4	0.75	8.8	1.6	600	11/1/2017 - 12/19/2017
5	1.0	8.9	1.6	800	12/19/2017 - 3/5/2018
6	1.0	10.0	2.0	1,000	3/5/2018 - Current

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 %

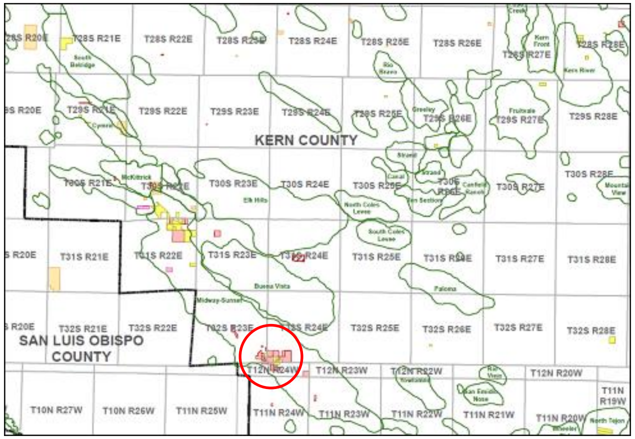
Aggregate Well Type Curve Assumptions and Results

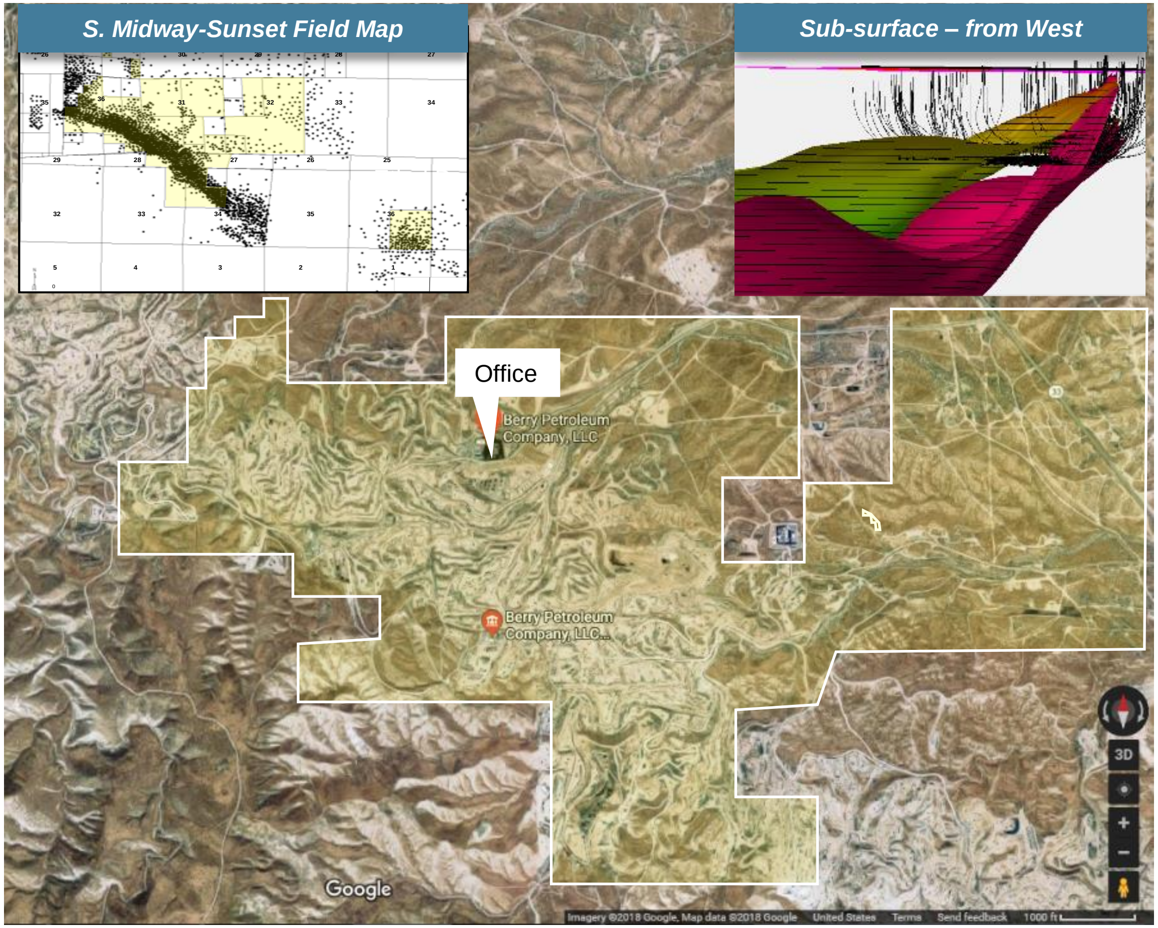
Gross Capex ($mm / well)	$ 0.5
Net EUR (Mboe)	29
% Oil	100 %
IP90 Production (Boe/d)	44.4
Brent Differential ($/Bbl)	$(3.63)
Fixed Opex per well ($k/month)	$ 2.83
Variable Opex[3] per boe ($/Boe)	$ 2.13
Steam[3] ($/Boe)	$ 8.94
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[4] as of May 31,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

Midway-Sunset – Homebase

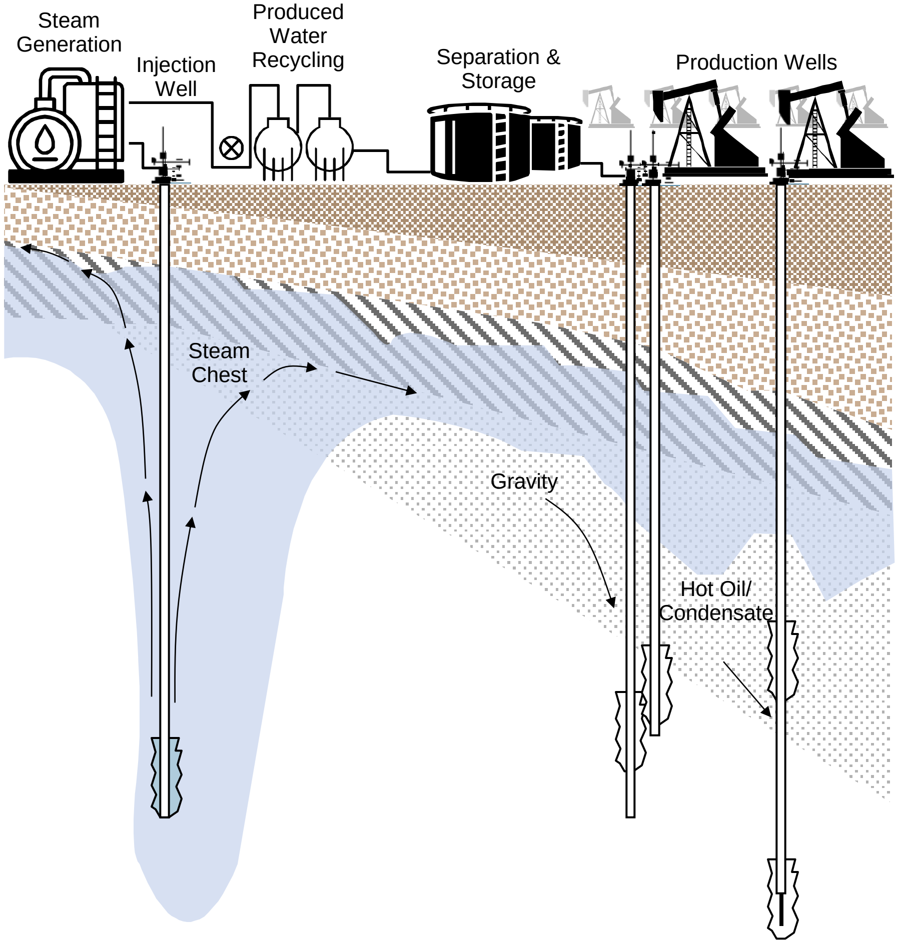
- 1,975 acres
- Some Fee Simple, some lease
- 2 Cogens (38 & 18 MW)





Overview of Thermal EOR Techniques using Steam

Steam Flood Diagram

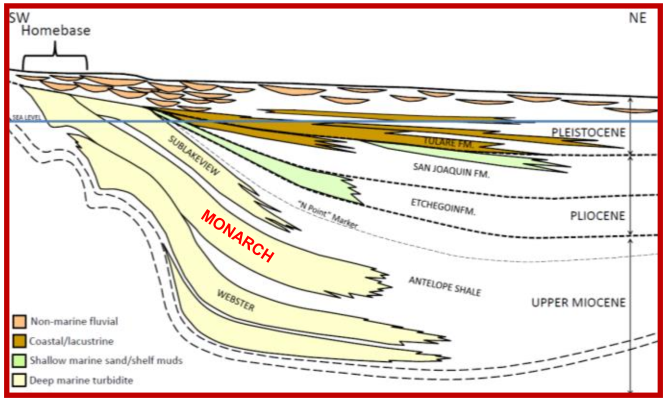


Steam as EOR Technique

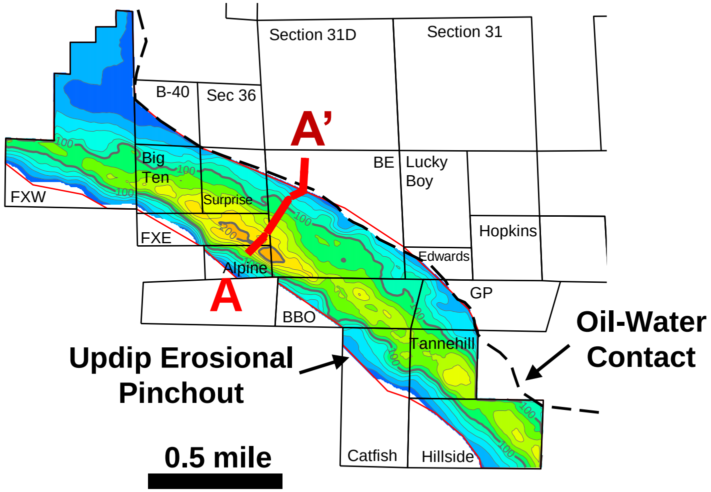
Overview	▪ Typical in shallow reservoirs with heavy crude ▪ Steam injection improves oil mobility and is a drive mechanism when developed as a flood ▪ The latent heat of condensation maximizes the energy transfer in the reservoir ▪ Thermal EOR increases recovery factors substantially and in some cases the reservoir may not produce without it
Depletion Techniques	▪ Cyclic steaming utilizes the same wellbore to inject steam and produce from the stimulated reservoir ▪ Steam flooding requires dedicated steam injectors and dedicated producers in various configurations ▪ Diatomite reservoirs are produced by cyclic steaming, utilizing the dilation and compression of the reservoir as the lift mechanism
Process	▪ Some produced water is filtered and softened and comingled with fresh water for steam injection ▪ Steam generators burn natural gas to convert the water into steam at the desired quality and pressure ▪ Steam is injected into the reservoir ▪ Oil and water (including condensed steam) is produced and separated. The oil is sold and the water is recycled through the system
Cost Inputs	▪ Natural gas, used to generate steam ▪ Water softening ▪ Production costs

Midway-Sunset: Monarch Sandstone Reservoir

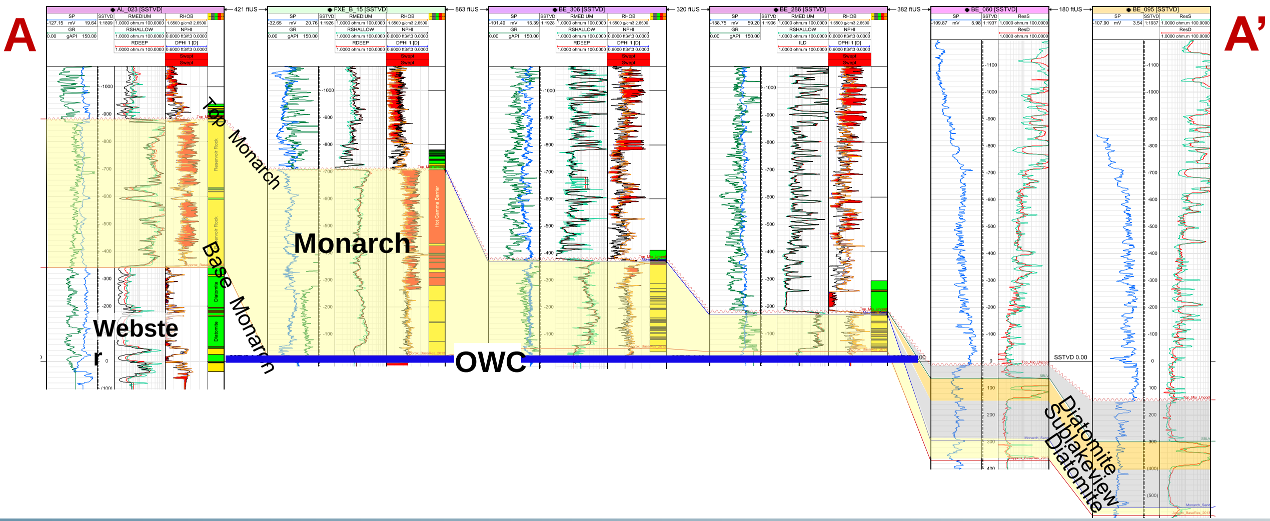
Midway-Sunset Sandstone Reservoirs



South MWSS Hydrocarbon Pore Volume Map

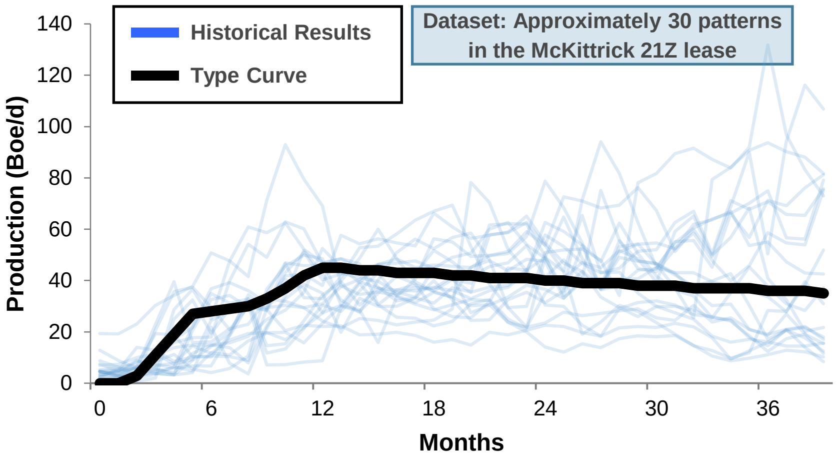


Monarch Cross Section

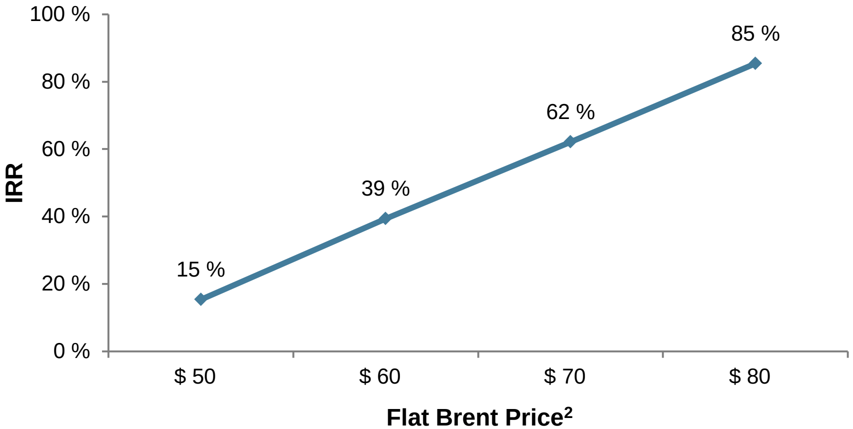


San Joaquin – Sandstone Flood Pattern Type Curve[1] Overview

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 (Tier 1 / Total)	1,860 / 2,284
WI / NRI	100 % / 95 %

Aggregate Pattern Type Curve Assumptions and Results

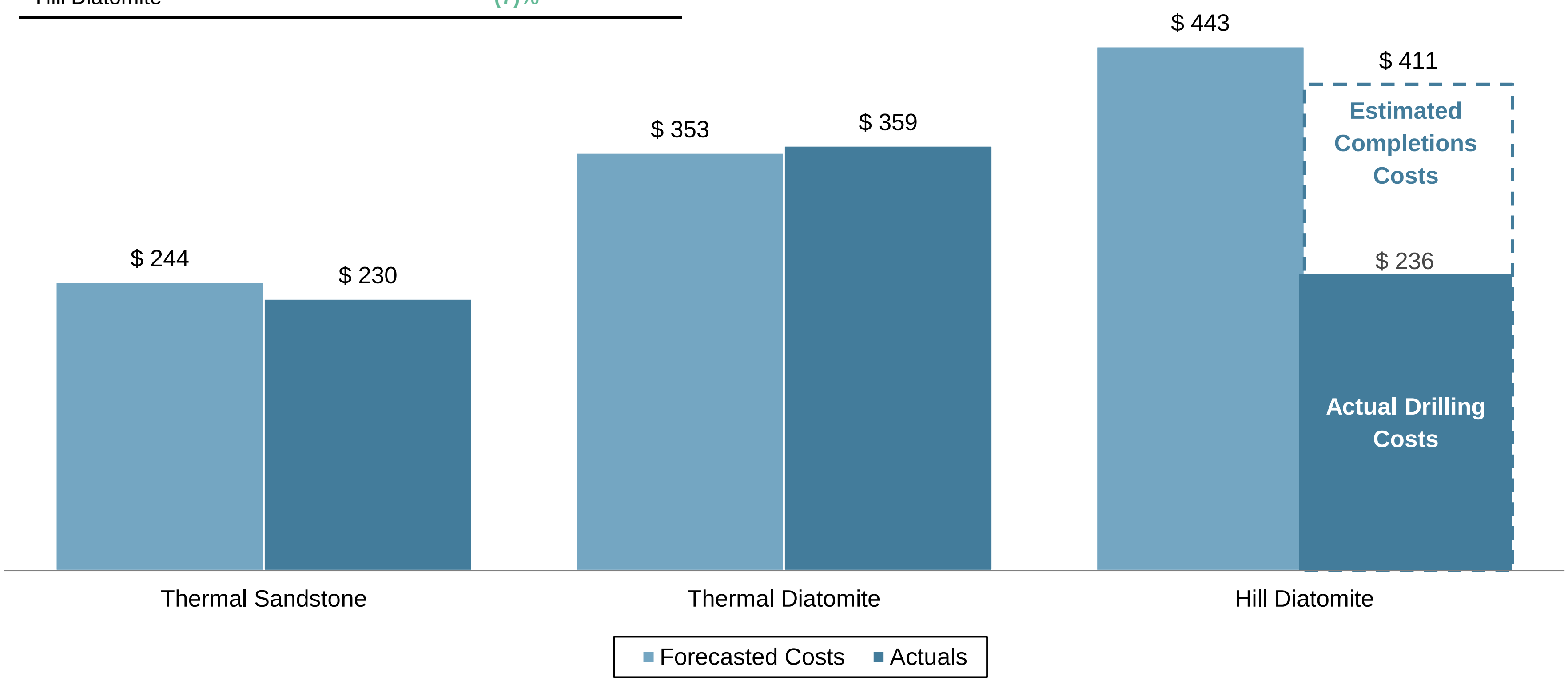
Gross Capex ($mm / pattern)	$ 1.2
Net EUR (Mboe)	114
% Oil	100 %
IP90 Production (Boe/d)	19.9
Brent Differential ($/Bbl)	$(5.63)
Fixed Opex per pattern ($k/month)	$ 4.40
Variable Opex[3] per boe ($/Boe)	$ 2.17
Steam[3] ($/Boe)	$ 16.67
Severance Taxes	1.9 %
Ad Valorem Taxes	3.5 %
IRR at Strip[4] as of May 31, 2018	65 %
PV-10[5] ($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] 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] 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.

San Joaquin Basin Remains a Significant Opportunity

- San Joaquin Basin still holds significant potential
  - Never bet against world-class source rocks
  - Back to basics – subsurface understanding
  - Technology
    - Drilling & completion – fit for purpose
    - 3D seismic
- Accessing the potential
  - Encourage competition – joint ventures and farm-outs
  - Engage state & local governments and regulators
  - Education

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
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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
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113	HILL 442C	1999-12-01	04030137370000
114	HILL 442D	1999-11-01	04030135380000
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144	HILL 642D	2013-03-01	04030478310000
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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

#	Well Name	Date	API
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

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

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.

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.

Thank you!

Berry Petroleum Corporation