



bry
BERRY
CORPORATION

**December 2024
Investor Presentation**

BRY
Nasdaq Listed



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Disclaimer

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Berry cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to acquisition transactions and the exploration for and development, production, gathering and sale of natural gas, NGLs and oil most of which are difficult to predict and many of which are beyond Berry's control. These risks include, but are not limited to, commodity price volatility; legislative and regulatory actions that may prevent, delay or otherwise restrict our ability to drill and develop our assets, including with respect to existing and/or new requirements in the regulatory approval and permitting process; legislative and regulatory initiatives in California or our other areas of operation addressing climate change or other environmental concerns; investment in and development of competing or alternative energy sources; drilling, production and other operating risks; effects of competition; uncertainties inherent in estimating natural gas and oil reserves and in projecting future rates of production; our ability to replace our reserves through exploration and development activities or strategic transactions; cash flow and access to capital; the timing and funding of development expenditures; environmental, health and safety risks; effects of hedging arrangements; potential shut-ins of production due to lack of downstream demand or storage capacity; disruptions to, capacity constraints in, or other limitations on the third-party transportation and market takeaway infrastructure (including pipeline systems) that deliver our oil and natural gas and other processing and transportation considerations; the ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; our ability to successfully execute other strategic bolt-on acquisitions; overall domestic and global political and economic conditions; inflation levels, including increased interest rates and volatility in financial markets and banking; changes in tax laws; and the other risks described under the heading "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K for the year ended December 31, 2023 and subsequent filings with the SEC.

The forward-looking statements in this presentation include management's projections of certain key operating and financial metrics. Material assumptions include but are not limited to a consistent and stable regulatory environment; the timely issuance of permits and approvals required to conduct our operations; access to and availability of drilling and completion equipment and other resources necessary for drilling, completing and operating wells; availability of capital; and access to third-party transportation and market takeaway infrastructure and our ability to sell oil and natural gas product to available markets. While Berry believes that these assumptions are reasonable and made in good faith in light of management's current expectations concerning future events, the estimates underlying these assumptions are inherently uncertain and speculative and are subject to significant risks and uncertainties which are difficult or impossible to predict and are beyond our control, including those discussed in this disclaimer. While Berry currently expects that its actual results will be within the ranges and guidance provided in this presentation, there will be differences between actual and projected results, and actual results may differ materially from those contained in these projections or any other forward-looking statement. Additionally, 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.

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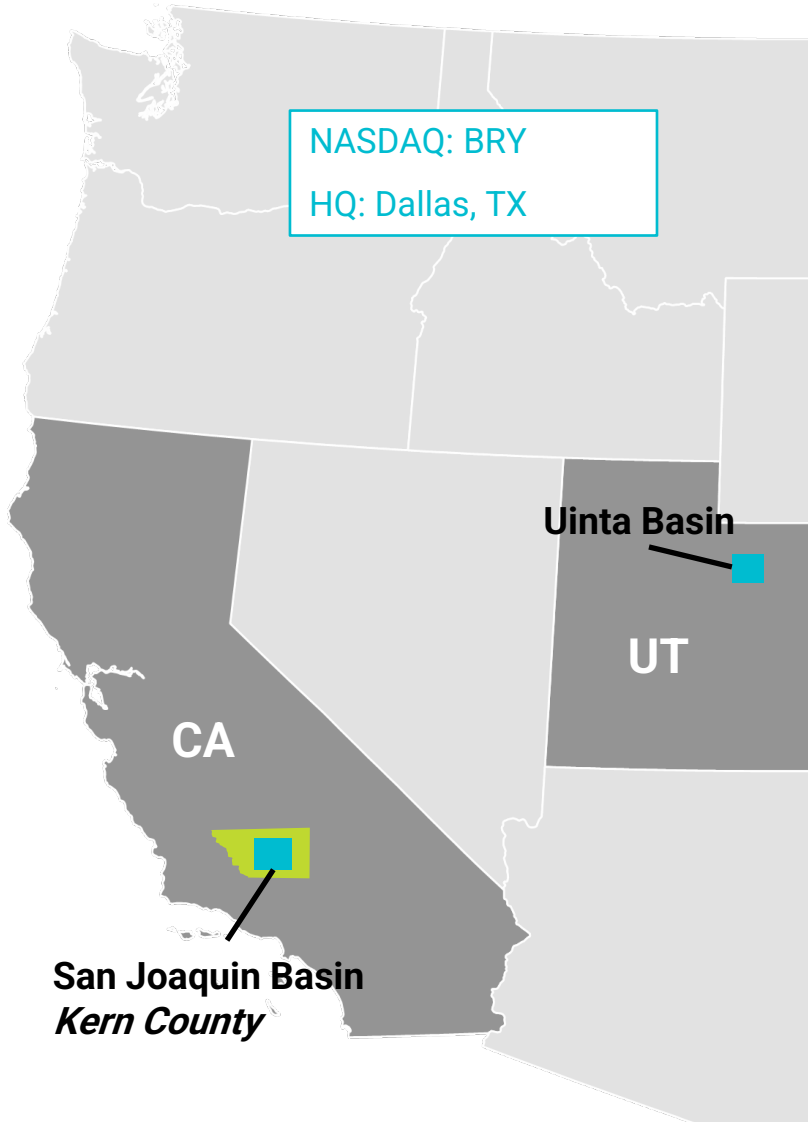
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Proved Reserves and PV-10 based on year end reserves and SEC pricing of \$82.84 Brent and \$2.63 Henry Hub as of December 31, 2023.

Reconciliation of Non-GAAP Measures to GAAP

Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for non-GAAP reconciliations to GAAP measures and additional important information.

Berry: A Western U.S. Energy Company



Company Overview

- Western U.S. independent upstream energy company focused on onshore, low geologic risk, low decline, long-lived conventional reserves:
 - San Joaquin Basin of California (Oil 100%)**
 - Uinta Basin of Utah (Oil 60% & Gas 40%)**
- Operate leading Well Servicing & Abandonment business (C&J Well Services) in California

2024 Highlights

Average Daily Production ³	25,400 boe/d (~92% oil)
Adj. EBITDA ¹	\$210mm
CFO / Free Cash Flow ¹	\$169 mm / \$84 mm
Leverage ²	1.5x
Stewardship	Achieved methane reduction goal over a year ahead of schedule: 80%+ reduction compared to 2022 baseline

Berry's Competitive Advantage

- ✓ Assets with attractive full cycle economics
- ✓ World class assets with vast resources providing substantial development opportunities
- ✓ Premium commodity market – indexed to Brent in California
- ✓ Experienced, proven and disciplined management and technical teams

¹Non-GAAP financial measure; please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for reconciliations to GAAP measures and additional important information - Q1-Q3 2024

²Leverage: Net Debt / TTM Adj. EBITDA

³January – November 2024

Our Strategy

Drive long-term value by capitalizing on our 100-year history of operating world-class assets

1

World-Class Assets

2

**Health, Safety &
Environmental
Compliance**

3

Strategic Growth

Generate sustainable free cash flow with leading rates of return from low capital intensity projects while maintaining balance sheet strength and high compliance standards

1

World-Class Assets

Driving increased profitability and operational excellence



World Class Assets

Deep Experience with Operating Assets Helps Maximize Efficiency, Minimize Capital Intensity, and Generate Leading Rates of Return

- Producing **25,400 boe per day YTD⁴**, consistent with 2023 annual average
- Stable, long-lived, oil-weighted asset base with **low annual decline rates of 11% - 14%**
- Over **\$2.0bn^{1,2}** of reserve value left to produce, of which **\$1.1bn^{1,2}** is over the next 5 years



Demonstrated success through the execution of our Thermal Diatomite strategy



- Thermal Diatomite is a prolific, world class asset, with ~1 million barrels of original oil in place per acre
- Technical excellence deployed to generate consistent cash flow from highly economic multi-year drilling inventory
 - Current Inventory: ~1,000 locations (sidetracks and new drills)
- Real-time monitoring of key performance indicators to drive base performance and value

~19% increase in production through superior reservoir management and workover activity from Nov 2019 through 2023

IRR >100%³ average for 28 Thermal Diatomite sidetracks drilled in 2024

Large runway of highly economic workover, sidetrack and new drill inventory in CEQA covered acreage

¹PV-10 based on YE reserves and SEC pricing as of 12/31/23

²Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for reconciliations to GAAP measures and additional important information

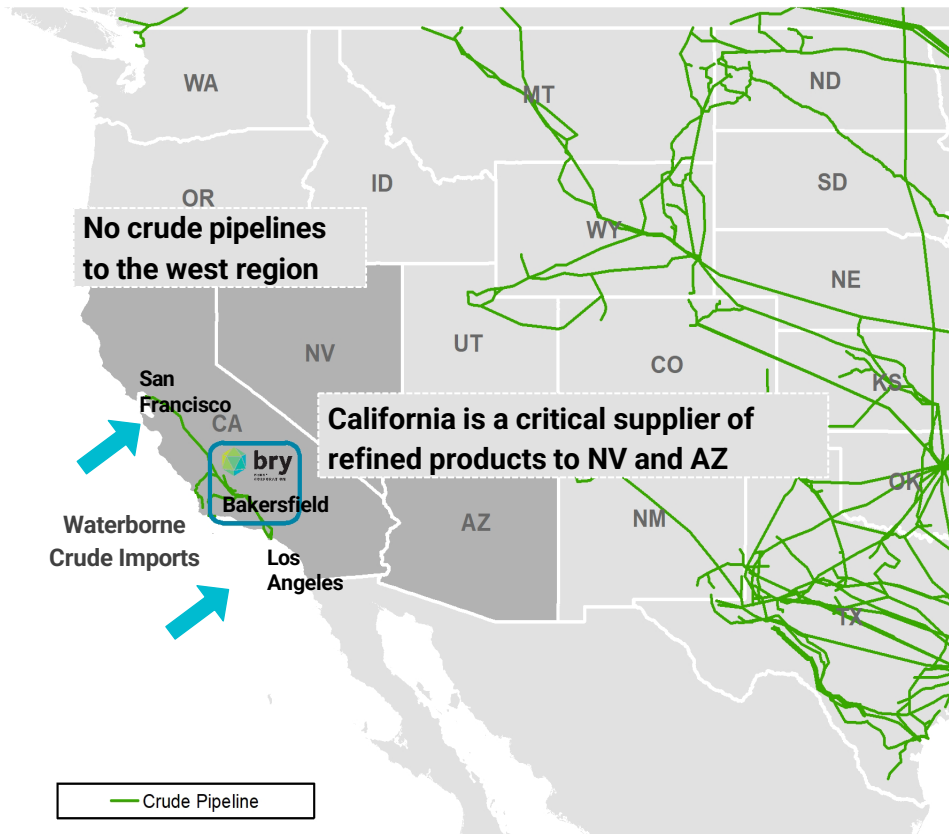
³Based on 2024 development and \$75/b Brent and \$3/mmbtu Henry Hub

⁴January – November 2024

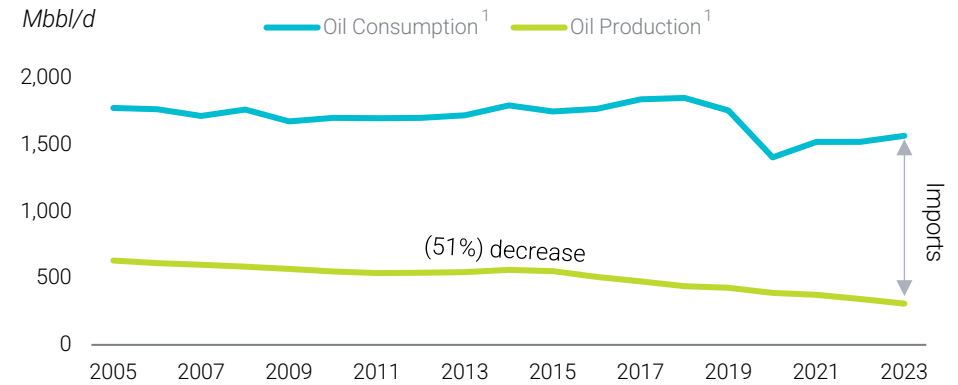
Primary Operations in Premium-Priced Market

Attractive Unit Economics Provide Significant Value

California is an Energy Island Due to Current Infrastructure



California's Supply and Demand Dynamics Drive Premium Oil Pricing¹



California Petroleum Facts:

- Consumes ~1.6 MMbbl/d of petroleum products¹
 - 2nd largest consumer in the U.S.³
 - ~5x of in-state production^{1,2}
- An energy island - no oil pipelines connecting to the rest of the U.S.
- 77% of crude oil is imported through tankers to California⁴
- California needs local production now and in the future!

¹Consumption info represents sum of oil products produced in CA; Production represents on-shore CA production only

²California Energy Commission <https://www.energy.ca.gov/data-reports/energy-almanac>

³According to the EIA in 2021 www.eia.gov/state/seds/sep_use/notes/use_print.pdf

⁴California Energy Commission <https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california>

2

**Health, Safety &
Environment**

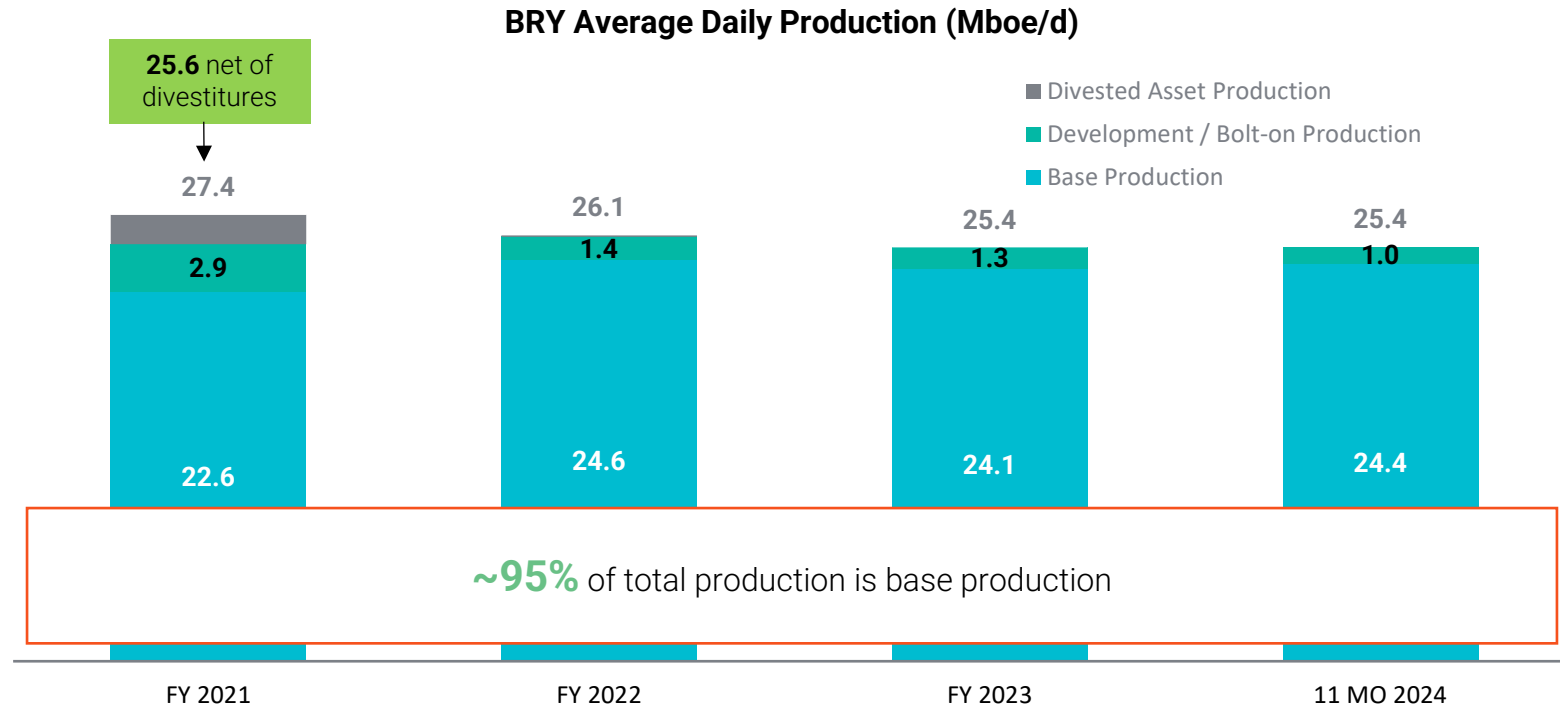
Continuous risk reduction by operating at the highest standards



Performance in California's Regulatory Environment

Long History Of Successful Operations in California, While Maintaining the Highest Compliance And Regulatory Standards

- Our **high quality, low decline assets** have enabled us to **maintain stable production** levels from an opportunistic mix of new drills, workovers and sidetracks
- Our **proven track record of operational excellence, our outstanding workforce,** and our **commitment to the highest compliance standards** have enabled us to continue to secure permits in California and maintain stable production levels over the last six years in spite of regulatory changes and permitting headwinds



Multiple Highly Economic Avenues to Maintain Production for Years

Short Term Executable 12+ months¹

- **Reservoir Management (thermal diatomite / steam flood optimization)**
 - **Increased production by ~1,000 bopd (19%)** in thermal diatomite from 2019 through 2023 without new drills
- **Utah Horizontal Development** (see slides 12-15)
 - ~100,000 prospective acres with >90% HBP
 - Marketing JV opportunity for 2025-26 HZ development activity
 - Leveraging farm-in opportunities to accelerate development and derisk existing acreage
 - Executed initial farm-in for 4 HZ, on production with results exceeding expectations
 - Second farm-in underway for additional >12 HZ
- **~35% of PUD locations are not dependent on Kern County EIR (246 PUDS)**
 - Sidetracks
 - 127 PUD locations - **4,958 bopd²**
 - New Drills in BRY CEQA covered areas
 - 86 PUD locations - **4,451 bopd²**
 - Utah development
 - 33 economic vertical locations - **1,295 boepd²**
- **Capex Reallocation for Bolt-On Acquisitions**
 - Pipeline of potential opportunities

Medium Term Potentially Executable 12 - 18 months¹

- **Proven alternatives for new drills in California³**
 - **NEPA covered areas (Federal Lands)**
 - 35 locations - **602 bopd²**
 - **Conditional Use Permit (Kern County as Lead Agent)**
 - Project specific with CEQA area review conducted by Kern County with review by CalGem as CEQA Responsible Agent. Plan to submit one application in Q4
 - **Area Study (CalGem as Lead Agent)**
 - Project specific with CEQA area review conducted by CALGEM. Application submitted at in review at CalGem
- **Re-Instatement of Kern County EIR**
 - Expected late 2025 to early 2026¹
 - Unlocks access to all locations

¹EIR reinstatement estimated time frame based on management and Kern County estimates

²Represents average production over first 12-month period; based on YE reserves as of 12/31/23

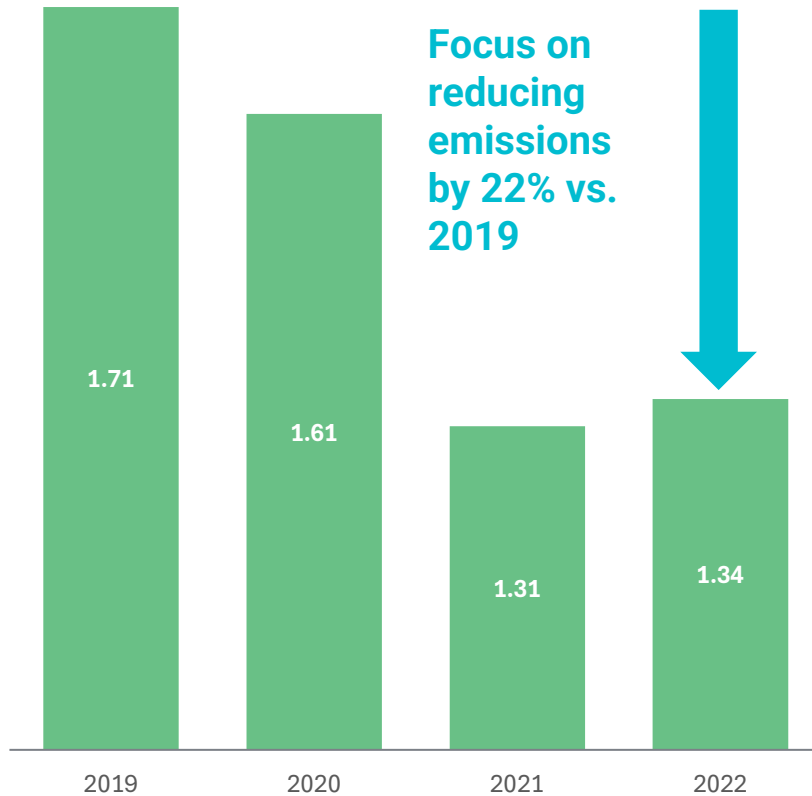
³These alternatives are proven in California outside of Kern County

Demonstrating Stewardship Commitment

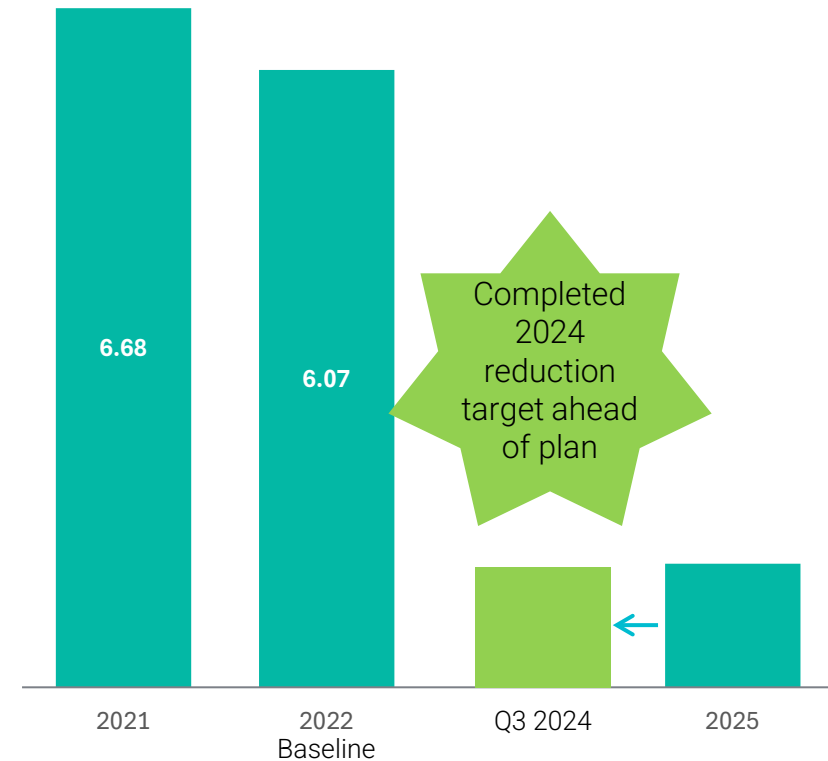
Reduced Methane Intensity by Over 80% and Investing in Carbon Reduction Efforts

- In 2024, established goal to reduce methane emissions by 80% compared to 2022 baseline
- \$2.5mm investment to replace all natural gas pneumatic devices, as the source of ~80% of BRY's 2024 methane emissions
- Investment expected to also result in significant cost savings from new EPA Waste Emissions Charges: expected to save the company over \$2.9 million dollars in 2024 WEC, plus given the escalating fee structure, the savings will likely be multi-fold in future years

Berry Scope 1 Emissions (millions mt, CO2e)



Berry Scope 1 Methane Emissions (thousands mt, methane¹)



Source: Berry "Sustainable Business Report", April 2024

¹Expected to result in an approximate 10% reduction in the total Scope 1 emissions associated with existing operations

3

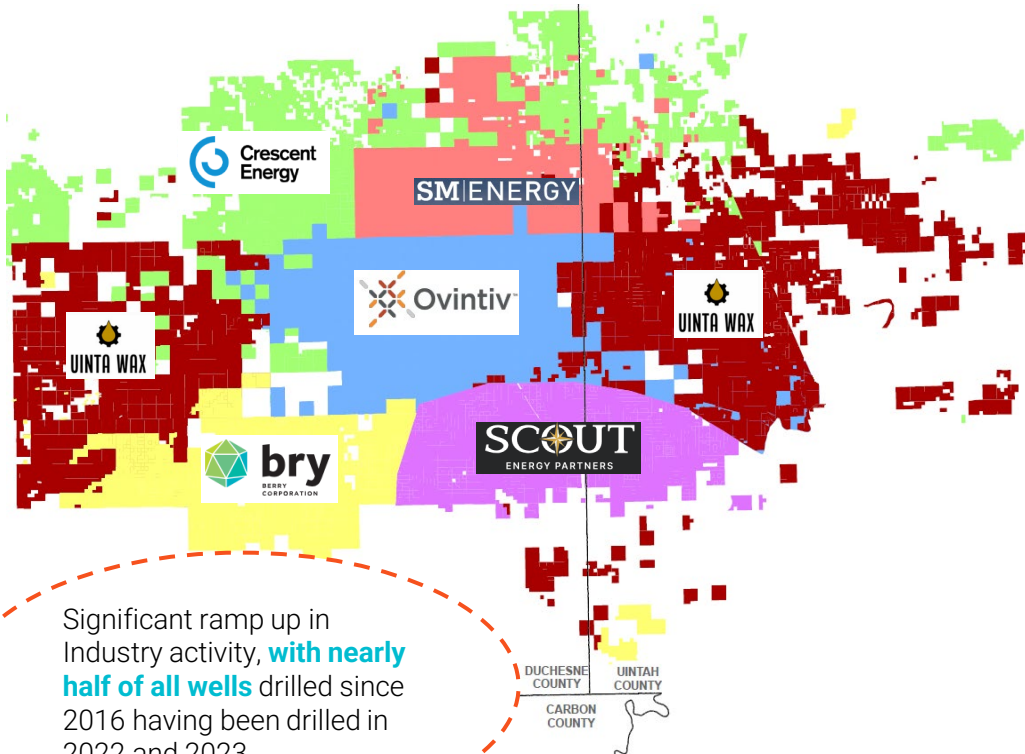
Strategic Growth

Capitalizing on our strengths to drive additional shareholder value

Utah Horizontal Development

Capture Significant Potential Upside in Uinta Basin With a Disciplined Investment Approach and Capital Partnerships

A Great Neighborhood



¹Non-operated farm-in positions

²On cost per foot drilled basis

Massive Resource Potential

- ~100,000 acres with current vertical production from 5 reservoirs that are being developed horizontally by our neighbors across the basin
- Accelerating appraisal from farm-in opportunities
 - Initial 4 horizontal wells from the prolific Uteland Butte reservoir¹
 - Performing at or above pre-drill estimates
 - Higher % of oil than anticipated
 - Executed second farm-in covering 5,800 gross acres in the Uteland Butte reservoir, with first two wells expected to be online this year
 - Evaluating JV partners for a portion of ~11 Hz Uinta Basin wells in 2025-26
 - Additional potential reservoir targets

Strong Economics, Competitive within Berry's world-class portfolio

- Based on initial testing results, single well economics of Uteland Butte wells could be highly economic at strip pricing
- Horizontal well development is expected to be highly profitable with low break-even economics

High Degree of Control and Capital Efficiency

- High working interest and majority of acreage is HBP - this allows Berry to develop at optimal pace, consistent with commitment to deliver Free Cash Flow
- Extensive existing infrastructure and Berry's culture of capital stewardship drive significantly lower cost wells: **20-30% less expensive than elsewhere in the basin**²

The Berry Advantage

Location

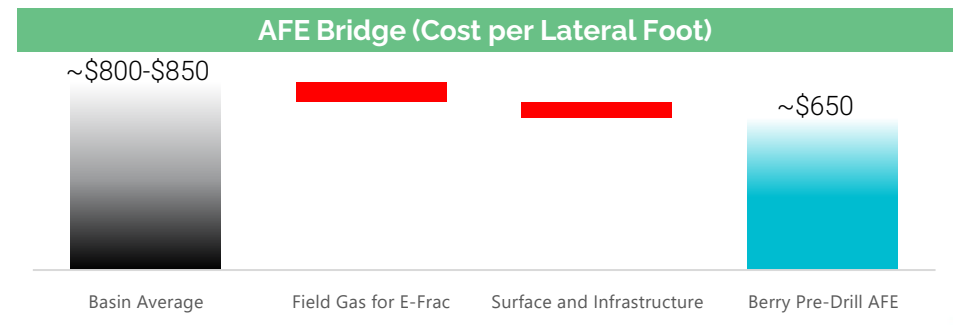
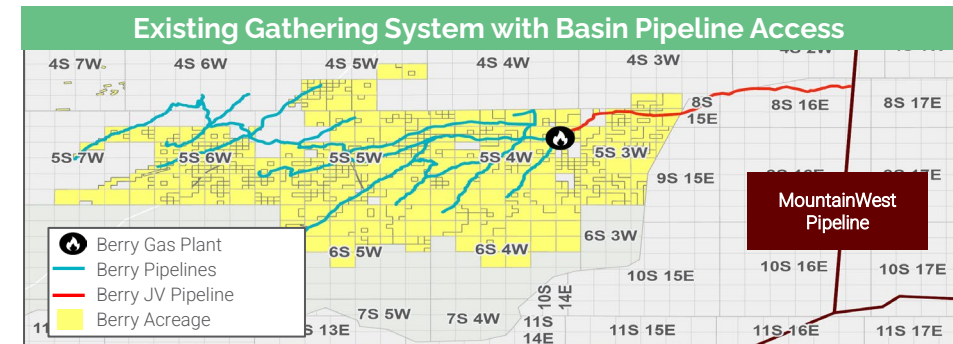
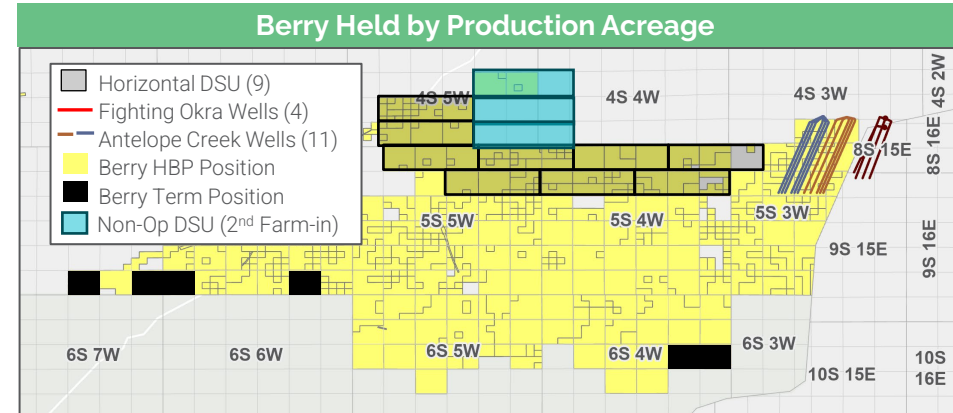
- High working interest and HBP acreage allows Berry to optimize development
- ~1,200 existing vertical wells on Berry's acreage producing from multiple intervals
- No entry land acquisition costs
- Targeting shallower intervals with average oil saturation of 70%

Infrastructure

- Crude is transported via truck under short-term contracts to several Salt Lake City Refineries and to the USGC via rail
- Berry operates an extensive gathering system and gas plant to gather and treat its production
- Berry has its own gas compression system that will be used for artificial gas lift

Cost Savings

- Pre-Drill Capex based on recent farm-in well design but further cost savings available from utilizing existing production and processing infrastructure
- Substantial capital savings from dual-fuel drilling and frac fleets
- Company owned high pressure compression in place for artificial lift and pads near processing plants allows for shorter runs on gathering lines



Second Farm-In

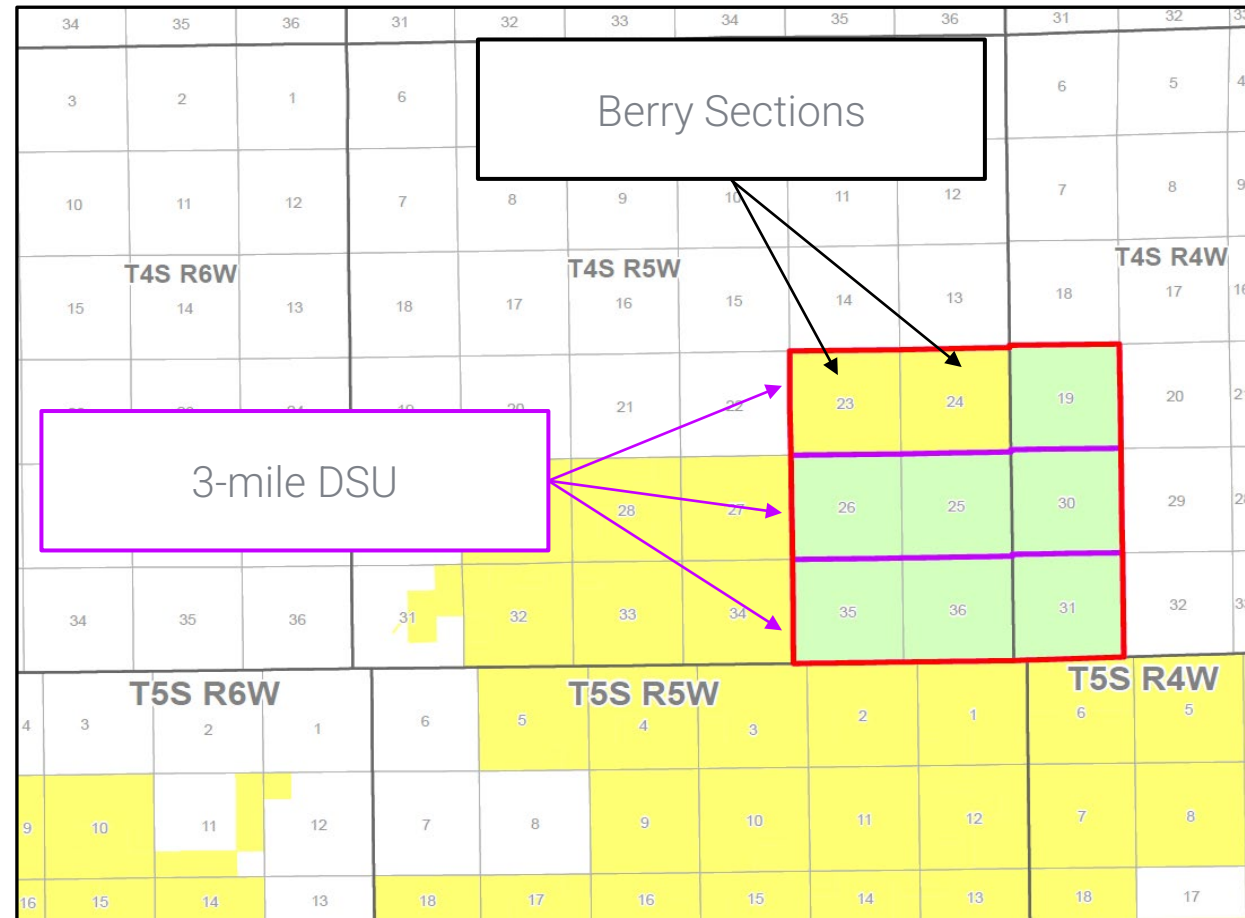
Uinta Acreage Trade Accelerates Production, Derisks Acreage

Expands and Derisks Berry Acreage

- Berry swaps an interest in a 2 sections for an equivalent interest in 3, 3-mile DSUs (drilling spacing unit)
- Non-op position; Operated by basin-leader
- Potential to de-risk western portion of Berry's 100,000 acre position in basin, >90% of which is held by production

Accelerates Development

- Covers approximately 5,800 gross acres, contemplating potentially 12 wells
- First 2 wells expected to be online early Q1 2026
- Additional wells planned for 2025 & 2026

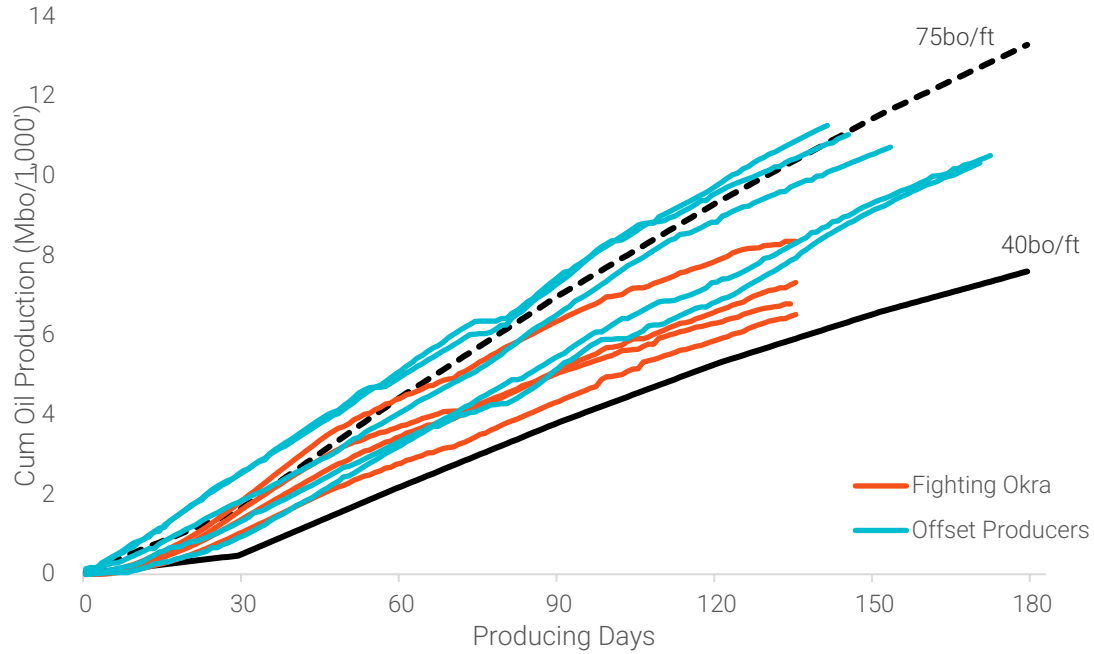




Significant Resource Upside with Attractive Returns

De-risked by New 2024 Horizontal Wells Within One Township from Berry's Acreage

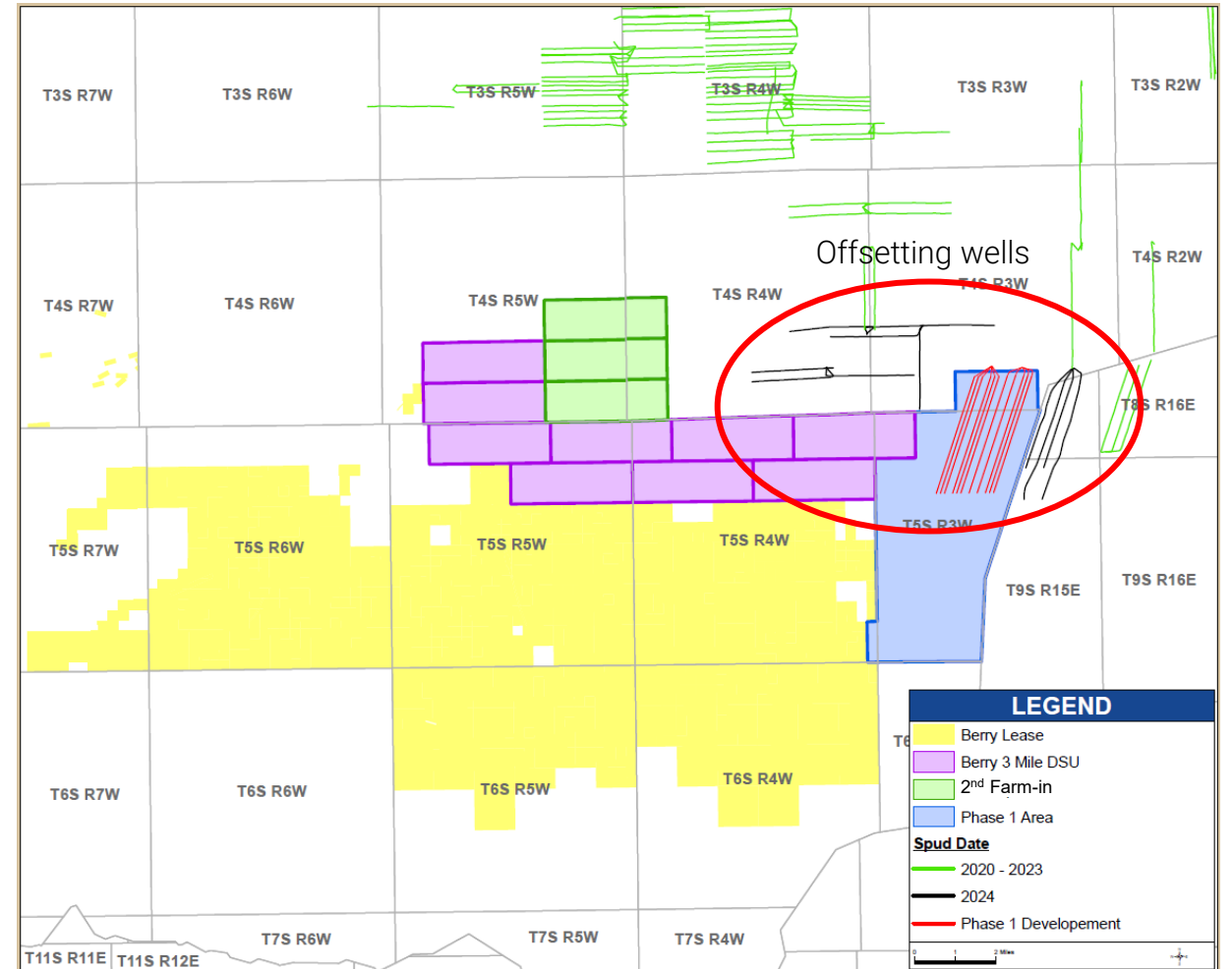
Performance of 2024 Vintage Proximity Wells to Berry



Returns Competitive with California Projects



Significant Ramp-Up in Activity in 2024 Offsetting Berry's Position



1. Based on Oct 13th, 2024 strip, WTI \$72.36/bo in 2025, \$69.46/bo in 2026, \$67.89 in 2027, \$67.04 in 2028 and \$66.49 thereafter, HH \$3.23/mmbtu in 2025, \$3.60 in 2026, \$3.62 in 2027, \$3.56 in 2028, \$3.47 thereafter.
 2. Data from Enverus and internal Berry materials, based on producing days

Capitalize on Existing Strengths and Expertise

Drive Returns, and Generate Future Revenue and Cash Flow

Acquiring Accretive, Producing Bolt-on Assets

Opportunistically target producing assets with upside potential which support goal of driving long-term value

Ability to apply expertise and operational discipline to other basins with similar characteristics

Disciplined approach to growth, including ability to reallocate existing capex to buy production at a competitive capital efficiency within free cash flow

History of financial benefits from accretive bolt-on acquisitions, with pipeline for future opportunities

C&J Well Services Business with Potential Upside

Operating one of the largest upstream well servicing and abandonment businesses in California

Existing oil and natural gas wells require ongoing spending to maintain production

Large opportunity for future revenue and cash flow within the state: ~34,000 idle wells, including 5,300+ deserted & orphaned wells¹



Financial Overview

Generating sustainable free cash flow with leading rates of return from low capital intensity projects while maintaining balance sheet strength and high compliance standards



Recent Financial Results and Highlights

Generating Sustainable Free Cash Flow

	Q3 2024	Q2 2024	FY 2023
Total Production (<i>mboe/d</i>)	24.8	25.3	25.4
Oil Production (<i>mmbbl/d</i>)	22.8	23.4	23.5
Realized Oil Price w/o Hedges (<i>\$/bbl</i>)	\$72.41	\$78.18	\$75.05
Realized Oil Price with Hedges (<i>\$/bbl</i>)	\$71.02	\$73.58	\$71.67
Realized Oil Price w/o Hedges % of Brent	92%	92%	91%
Realized Oil Price with Hedges % of Brent	87%	87%	87%
Adj. EBITDA ¹ (<i>\$mm</i>)	67	74	268
Adj. G&A ¹ (<i>\$mm</i>)	17	17	74
Cash flow from Operations (<i>\$mm</i>)	71	71	199
Capex (<i>\$mm</i>)	26	42	73
<i>E&P Capex (\$mm)</i>	25	42	65
Free Cash Flow ¹ (<i>\$mm</i>)	45	29	126

✓ Q3 2024 Operating Results Tracking to Plan

- Average daily production of 24,800 boe/d
- Adj. EBITDA¹ \$67mm
- ↑ FCF¹ \$45mm, up \$16mm from Q2 '24

✓ Methane Reduction Goal Achieved, Ahead of Schedule

- Targeted cutting methane intensity by 80% by YE 2025, completed Q3 '24
- \$2.5mm investment in 2024 replacing natural gas pneumatic devices will save \$2.9mm in waste emission charges in 2025, multi-fold savings in following years

✓ Continuing Cost Optimization Programs

- ↓ LOE, net of gas hedges, decreased by approximately 2% for the third quarter.
- ↓ Adj G&A expenses on a boe basis for Q3 were down 3% compared to Q2
- Opex and G&A optimization programs will continue throughout the year

✓ Declared Q3 2024 Dividends

- \$0.03/share fixed

¹Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for reconciliations to GAAP measures and additional important information

Disciplined Financial Policies

Investing for Long-term Value Creation Through the Commodity Cycle

Prudent Balance Sheet Management

Target Net Debt to EBITDA³ of lower than 1.5x through commodity price cycle

Capital structure prioritizes debt reduction and shareholder returns

Disciplined and Returns Focused Capital Spend

Fund organic development opportunities while generating sustainable Free Cash Flow^{1,3}

Pursue strategic and accretive bolt-on acquisitions that improve long-term value and the leverage profile

Focus on Maintaining Liquidity to Manage Through Cycles

\$545mm term loan² provides additional support for the Company's working capital and operating needs going forward

Active hedging program to manage cost and effectively achieve price realization throughout commodity cycles

¹Free Cash Flow = Cash Flow from Operations - Capital Expenditures

²\$545mm of commitments consisting of a \$450mm initial term loan and a \$95mm delayed draw for working capital purposes

³Non-GAAP financial measure. Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for non-GAAP reconciliations to GAAP measures and additional important information



2024 Full Year Guidance

as of 11/7/2024

	Low	High
Average Daily Production (boe/d) ¹	24,600	25,800
Expenses from field operations (\$/boe) ²	\$26.50	\$29.50
E&P non-production revenues (\$/boe) ³	\$1.80	\$2.00
Natural gas purchase hedge settlements (\$/boe) ^{4,5}	\$0.60	\$0.90
Taxes, Other than Income Taxes (\$/boe)	\$6.50	\$7.50
Adjusted General & Administrative (G&A) expenses (\$/boe) ^{6,7}		
• E&P Segment & Corp	\$6.30	\$6.50
• Well Servicing and Abandonment Segment	\$1.30	\$1.50
Capital Expenditures - E&P, Well Servicing Segment & Corp (\$mm) ⁸	\$95	\$110
Well Servicing & Abandonment Segment Adjusted EBITDA (\$mm) ⁶	\$6	\$8

¹Oil production is expected to be approximately 93% of total

²Expenses from field operations include lease operating expenses, electricity generation expenses, transportation expense, and marketing expenses

³E&P non-production revenues include sales from electricity, transportation, and marketing activities

⁴Natural gas purchase hedge settlements is the cash (received) or paid from these derivatives on a per boe basis

⁵Based on natural gas hedge positions and basis differentials as of December 31, 2023, and the Henry Hub gas price of \$3.38 per mmbtu

⁶Adjusted General & Administrative expenses and Well Servicing and Abandonment Segment Adjusted EBITDA are non-GAAP financial measures. The Company does not provide a reconciliation of these measures because the Company believes such reconciliation would imply a degree of precision and certainty that could be confusing to investors and is unable to reasonably predict certain items included in or excluded from the GAAP financial measures without unreasonable efforts.

This is due to the inherent difficulty of forecasting the timing or amount of various items that have not yet occurred and are out of the Company's control or cannot be reasonably predicted. Non-GAAP forward-looking measures provided without the most directly comparable GAAP financial measures may vary materially from the corresponding GAAP financial measures

⁷See further discussion and reconciliation in "Non-GAAP Financial Measures and Reconciliations"

⁸Total company capital expenditures, including E&P segment, well servicing & abandonment segment and corporate

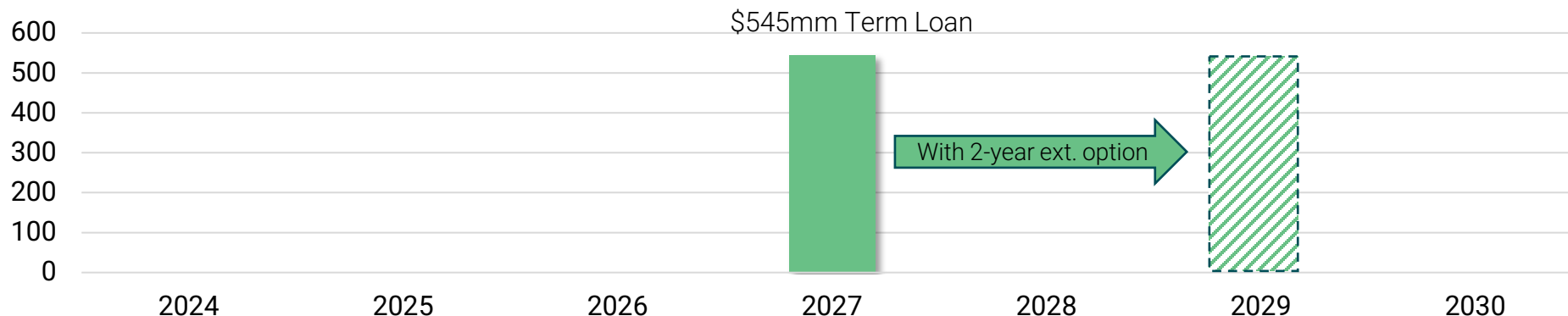
Maintaining Balance Sheet Strength

We Aim to Achieve a Prudent and Attractive Long-term Leverage Profile of Lower than 1.5x¹

Refinance Update

- \$545mm 1st lien term loan
 - \$450mm available initially
 - \$95mm delayed draw for working capital purposes
 - Allows for super priority RBL in place of delayed draw
- 3-year term loan with two 1-year extension options
- Assurance of capital availability to fund high return development opportunities
- Repayment Fee: 1st two years at par, 102.75 thereafter
- SOFR + 750 bps on drawn amounts
- 10% annual amortization

Maturity Schedule









¹Leverage: Debt / TTM Adj. EBITDA

²TTM = trailing twelve months; Non-GAAP financial measure. Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for non-GAAP reconciliations to GAAP measures and additional important information

Investment Highlights

Capitalizing on our 100-year History and Experience to Create Sustainable Free Cash Flow and Long-term Value

-  Driving increased profitability and operational excellence with world-class assets
-  Operating at the highest standards with a focus on health, safety and environment
-  Leveraging our strengths to pursue strategic opportunities and drive additional shareholder value
-  Capitalizing on significant position with potential for transformational growth in emerging horizontal Uinta Basin play with no entry cost
-  Maintaining balance sheet strength, spending within free cash flow, and investing for long-term value creation through the commodity cycles
-  Generated sustainable **free cash flow with over \$1.1bn** in cash flow from operations over the last 5 years¹

¹Through Q3 2024

Preliminary 2025 Program

1

World-Class Assets

2

Health, Safety & Environment

3

Strategic Growth

- Estimated capital spend of \$105-120 MM¹, focused on driving value through Utah horizontal development and California sidetracks
 - Capital estimated to be 60% CA and 40% UT
 - Primarily focused on sidetracks in CA (Inventory of ~200 with RORs averaging 75% - 100%)
 - Development of UT horizontal play (~100,000 prospective acres)
- 25H1: Executing drilling program to sustain production
- 25H2: Potential for modest production growth
- Enhancing sustainability disclosure with additional reporting
- Deploying continuous field methane detection technology in CA
- Expanding Methane Leak Detection and Repair (LDAR) Program in UT
- Accelerating appraisal phase and derisking of Berry UT acreage for horizontal development:
 - Marketing Uinta Basin joint venture opportunity
 - Testing two reservoir targets in horizontal development program
 - JV participation in 11 horizontal wells: 5 in 2025 and remainder in 2026
 - Participating in second farm-in opportunity
 - Potentially 12 additional horizontal wells: 6 to come online in 2025 and remainder in 2026

¹Total Company – E&P, Well Servicing Segment, and Corporate – Subject to Board Approval

Appendix

Led by an Experienced Management Team

Name	Position	Prior Industry Experience	Years in Industry
	Fernando Araujo CEO	  	30+
	Danielle Hunter President		13+
	Mike Helm VP, CFO, & CAO	 	16+
	Jordan Scott VP, General Counsel & Corporate Secretary	 	12+
	Nick Smith VP, Business Development	  	17+

Significant experience operating and managing O&G businesses across numerous domestic and international basins



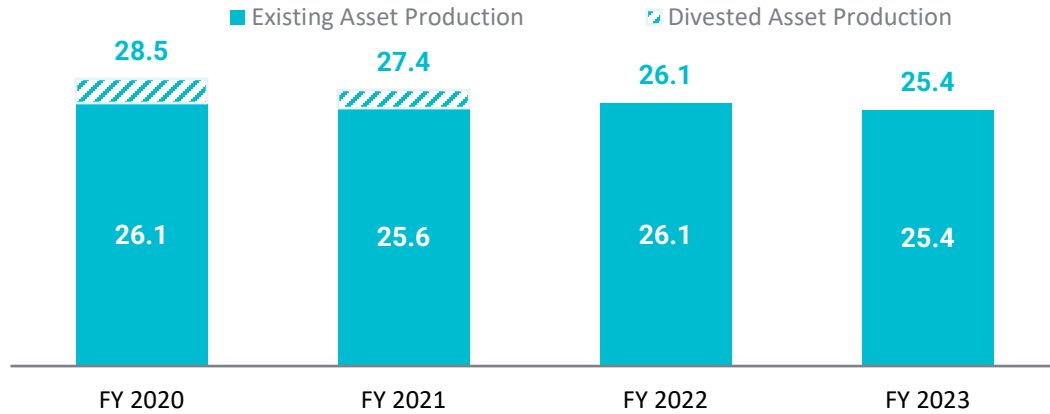
Appendix

Reconciliation of Non-GAAP Measures

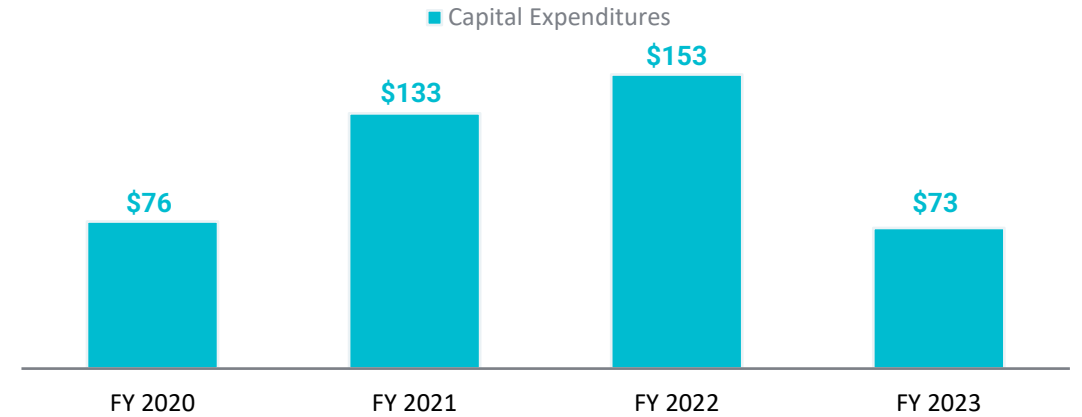
For reconciliations of Non-GAAP to GAAP measures and other important information see <https://ir.bry.com/non-gaap-reconciliations-to-gaap>

Key Business Statistics

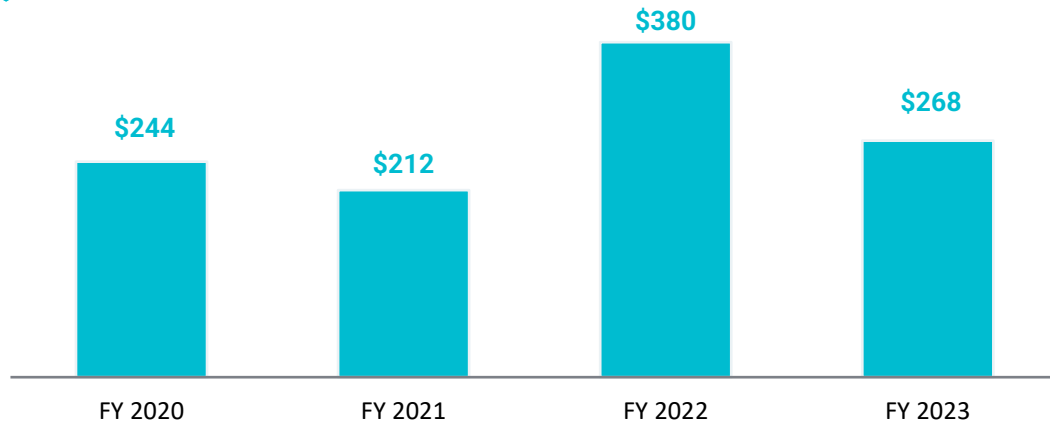
Average Daily Production (Mboe/d)



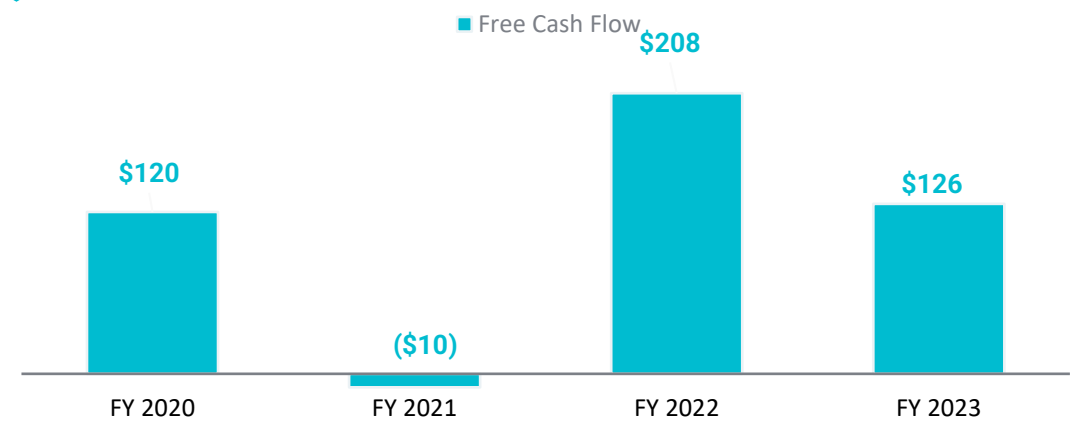
Capital Expenditures³ (\$MM)



Adjusted EBITDA² (\$MM)



Free Cash Flow^{2,4} (\$MM)



¹Expenses on field operations include lease operating expenses, electricity generation expenses, transportation expense, marketing expenses and net cash paid for derivative settlements

²Non-GAAP financial measure. Please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for non-GAAP reconciliations to GAAP measures and additional important information

³Capital expenditures exclude \$18 MM acquisition of Antelope Creek assets in Utah during Q1 2022., \$51 MM acquisition of Macpherson assets in Q3 2023 and \$31 MM acquisition of working interest in Macpherson assets in Q4 2023

⁴Free Cash Flow = Cash Flow from Operations – Capital Expenditures

Hedging Update: Oil

As of 9/30/2024	Q4 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Brent - Crude Oil production						
Swaps						
Hedged volume (bbls)	1,438,656	4,951,125	2,633,268	3,056,000	2,378,000	724,000
Weighted-average price (\$/bbl)	\$76.93	\$76.06	\$71.76	\$70.66	\$68.36	\$67.44
Sold Calls¹						
Hedged volume (bbls)	92,000	296,127	1,251,500	318,500	-	-
Weighted-average price (\$/bbl)	\$105.00	\$88.69	\$85.53	\$80.03	-	-
Purchased Puts (net)²						
Hedged volume (bbls)	322,000	296,127	1,251,500	318,500	-	-
Weighted-average price (\$/bbl)	\$50.00	\$60.00	\$60.00	\$65.00	-	-
Sold Puts (net)²						
Hedged volume (bbls)	46,000	-	-	-	-	-
Weighted-average price (\$/bbl)	\$40.00	-	-	-	-	-

¹Purchased calls and sold calls with the same strike price have been presented on a net basis

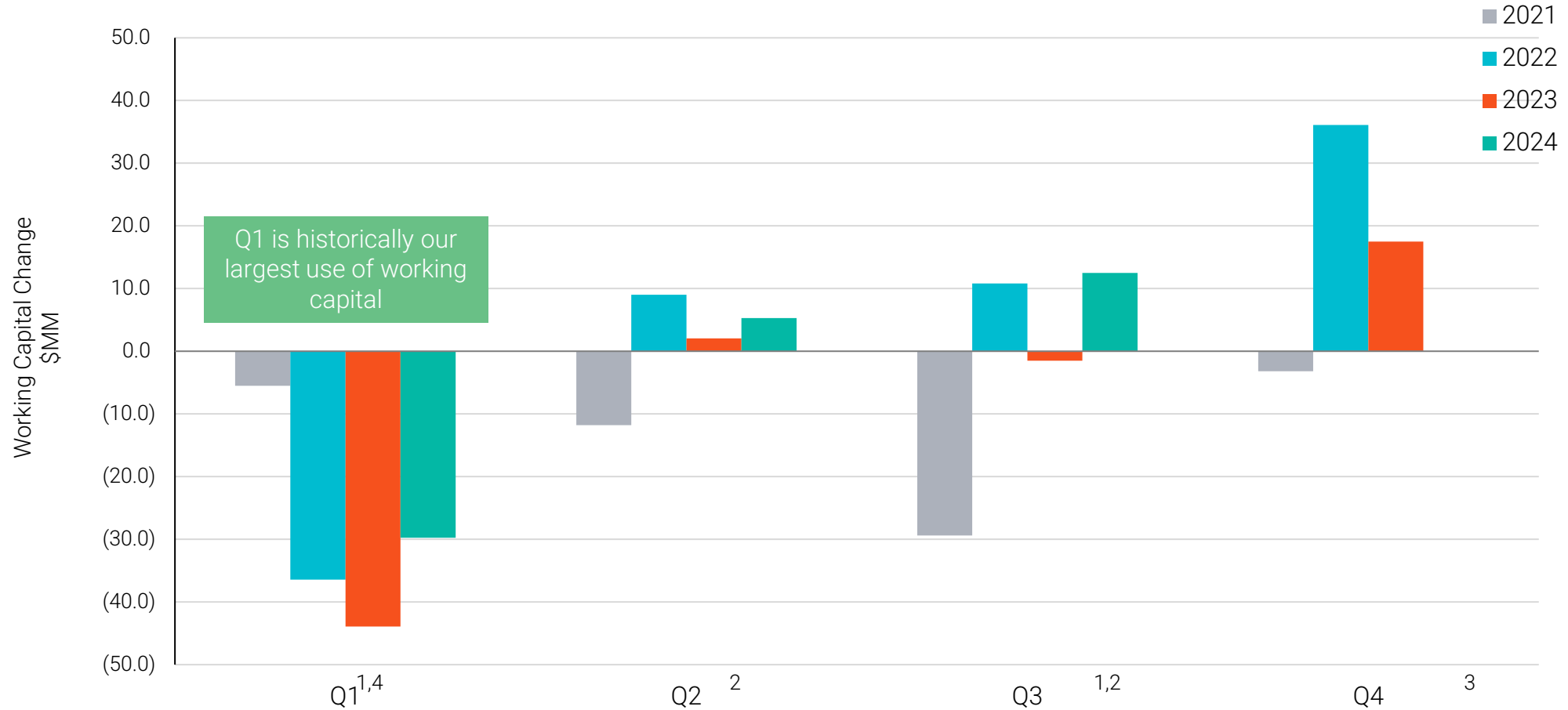
²Purchased puts and sold puts with the same strike price have been presented on a net basis



Hedging Update: Fuel Gas

<i>As of 9/30/2024</i>	Q4 2024	FY 2025	FY 2026
NWPL Rockies - Natural Gas purchases			
<i>Swaps</i>			
Hedged volume (mmbtu)	3,680,000	13,380,000	3,040,000
Weighted-average price (\$/mmbtu)	\$3.96	\$4.27	\$4.26

Quarter Over Quarter Working Capital Changes



¹Each Q1 and Q3 period includes semi-annual interest payments

²Q3 2023 & Q4 2023 included price increase (Q3) or decrease (Q4) impacting Accounts Receivable

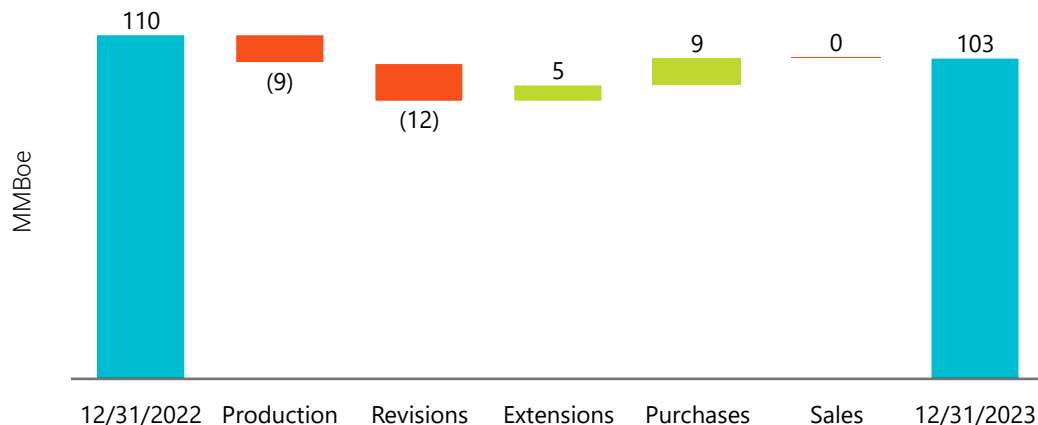
³Q4'22 includes higher AP build, AR reductions and increased capex program

⁴Q1'23 includes higher working capital usage and higher annual royalty payment due to higher 2022 prices

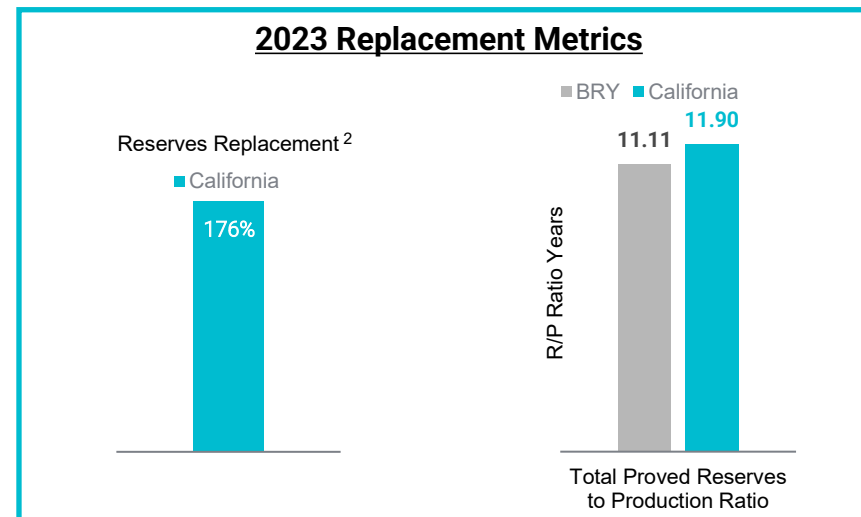
Proved Reserves

YE 2023 Proved Reserves – DeGolyer and MacNaughton Reserve Report

Total Berry Reserve Reconciliation



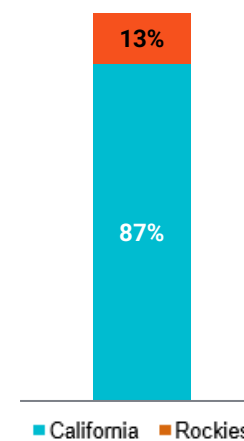
2023 Replacement Metrics



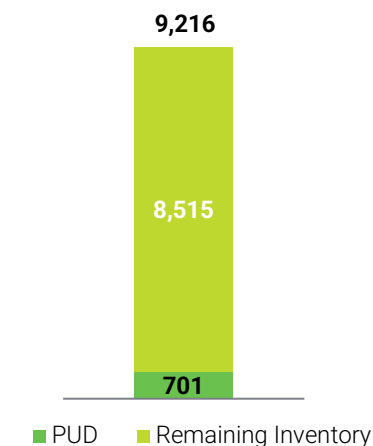
Reserve Highlights

- Total proved reserves PV10 of \$2 bn¹, predominately in California's oil rich basins
- Strong inventory base with continued focus on portfolio optimization
- Long reserve life in California with a reserves to production ratio of ~12 years²
- California reserve replacement ratio of 176%²
- **~35% of PUD locations³ not dependent on Kern County EIR**
 - 246 locations; PV10 of \$440mm (~50% of PUD PV10 value)²

2023 Reserves



Est. Drilling Locations



¹PV-10 based on YE reserves and SEC pricing as of 12/31/23. Non-GAAP financial measure; please see <https://ir.bry.com/non-gaap-reconciliations-to-gaap> for reconciliations to GAAP measures and additional important information

²Additions (Production + Revisions + Extensions + Purchases) / Production. Based on year end reserves and SEC pricing as of December 31, 2023. See disclosures on page 1 for additional information and assumptions

³Includes sidetracks, new drills in CEQA (California Environmental Quality Act) covered areas and Utah

California Regulatory Key Issues

Issue	Status	Mitigation / Impact
New Well Permitting	<p>The California Environmental Quality Act (CEQA) requires a review of the environmental impacts of various projects, including drilling new wells. In Kern County, since 2015 with Kern County's certification of a county-wide Environmental Impact Report covering oil and gas activities (KC EIR), this review has traditionally been conducted at the county level. The KC EIR created a streamlined process for local permitting of all oil and gas production.</p> <p>In 2015, environmental justice groups filed suit challenging the sufficiency of the KC EIR, and the Kern County EIR has been suspended intermittently during that time. Most recently, in March 2024, the Appellate Court rule that the KC EIR is inadequate in 3 areas and directed the County to revise the EIR, recirculate the EIR for public comment, and present to the (lower) Superior Court for confirmation that the issues were adequately addressed. The three areas to be addressed are:</p> <ul style="list-style-type: none"> • Mitigation required for loss of agricultural land; • Health Risk Assessment's support for the setback adopted to addressing the potential cancer-causing effects of oil drilling multiple wells; and • Analysis of the need for mitigation of groundwater depletion in disadvantaged communities. <p>Until the KC EIR is reinstated (currently expected in late 2026 to early 2026), to obtain new drill permits operators need to demonstrate CEQA compliance through environmental reviews conducted separate from the Kern County EIR.</p>	<p>Since 2021, we have held production relatively flat through sidetrack and workover activities, complemented by some new wells in Utah and California. We believe that our extensive inventory of California sidetracks, and workovers, as well as new well locations in areas with valid CEQA review, plus Utah opportunities, can sustain production for at least the next 24 months (through 2026).</p> <p>The Kern County EIR does not impact – and California is still issuing – workover and sidetrack permits throughout Kern County, as well as new drill permits in areas (e.g., North Midway Sunset area) where BRY has a separate valid CEQA review. BRY is pursuing available paths for new CEQA reviews in areas.</p>
Setbacks	<p>SB1137 – Health Protective Zones - established 3,200 setbacks around “sensitive receptors” and prohibits CalGEM from issuing permits to drill new wells or to workover existing wells within the setback area. The bill also established new monitoring and reporting requirements in setback areas.</p> <p>This regulation went into effect in June 2024, following the withdrawal of an industry-led referendum. However, in one of his final bill signings, the Governor signed AB 218, a budget trailer bill containing a number of extensions related to the setback law, including a three year extension on the deadline for operators to have leak detection and monitoring plans fully implemented to July 1, 2030.</p>	<p>Implementation and compliance is not expected to result in any material change to our overall existing proved developed producing reserves or current production rates, nor to significantly increase our costs.</p> <p>Where economical, BRY purchased sensitive receptors to mitigate the impact.</p>
Moratorium on new high pressure steam injection (HPSI) permits	<p>In November 2019, the State Department of Conservation announced a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by other operators (e.g., Chevron). In February 2022, CalGEM issued letters to operators who had conducted high pressure cyclic steam operations in the past, indicating that it intended to revisit the moratorium on a field-by-field basis.</p> <p>Berry's thermal diatomite asset uses high pressure cyclic steam to produce. Berry has applied to CalGEM to resume high-pressure cyclic steam operations in this area via a revised Underground Injection Control (“UIC”) program to support our future development plans. Berry expects its application to CalGEM to be approved; the moratorium on new HPSI has been effectively lifted by the regulator.</p>	<p>To date, BRY has mitigated the production impact this through innovative reservoir engineering techniques by which we have been able to keep production flat and even grow production in some areas.</p>
P&A Bonding Requirements for Operators	<p>AB1057 – Bonding and Financial Security Program – became effective in 2019, establishing new bonding requirements, specifically, CalGEM was directed to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted up to a max \$30m cap. Although not codified, it is our understanding that the \$30m cap applies on a corporate / organizational basis, and is not per operating company (CalGEM agreed with CRC on a shared liability structure with one \$30m bond covering all operators).</p> <p>BRY has not yet received its Notice of Applicability (NOA) from CalGEM, but expect it will be issued in 2025; BRY will have at least 180 days to work with CalGEM on its compliance requirements.</p>	<p>BRY's current bonding requirements are approximately \$4.5m in total, costing approximately \$70,000 per year.</p> <p>We cannot predict whether and to what extent our bonding requirements will increase. If CalGEM were to increase BRY's bonding requirements to the statutory cap, our current estimate is that the \$30mm bond would cost approximately \$500m/yr (1.5-2% on \$30mm).</p>
Bonding Requirements for New Operators	<p>AB 1167 - Orphan Well Prevention Act, became effective October 2023 and imposes financial assurance requirements on operators who acquire the right to operate a well or production facility in California. It is intended to ensure that there is money available to pay for plugging and abandoning wells even if an operator were to go bankrupt.</p> <p>In connection with CRC's acquisition of Aera, the State Department of Conservation stated that it applies to direct changes in the operator of record, and does not apply to corporate transactions where the operator does not change.</p>	<p>May restrict M&A / A&D activity – considerations include bonding costs and target entity liabilities</p>
Idle Well Requirements	<p>In April 2019, CalGEM issued updated Idle Well Regulations to implement AB2729 that include a comprehensive well testing regime to demonstrate the mechanical integrity of idle wells, a compliance schedule for testing or plugging and abandoning idle wells, the collection of data necessary to prioritize testing and/or plugging idle wells, an engineering analysis for each well idled 15 years or longer, and requirements for active observation wells. These Idle Well Regulations require Operators to P&A idle wells under two regimes: BRY must annually eliminate at least (1) 6% of long-term idle wells under an Idle Well Management Plan and (2) 10% of idle wells included in a Testing Waiver Plan. AB 1866, effective January 1, 2025, modifies Operators' annual P&A obligations based on each Operator's total number of idle wells (i.e. those included in the Idle Well Management Plan + Testing Waiver Plan). CalGEM is in the process of updating the Idle Well Regulations to implement AB 1866, with considerations including whether to combine the Idle Well Management Plan + Testing Waiver Plan requirements into one.</p>	<p>The estimated impact will be fully assessed once CalGEM has issued the updated Idle Well Regulations. Based on our preliminary assessment, we expect to the impact to our plugging and abandoning costs to be immaterial and within historical ranges since 2019.</p>



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