Denbury

26th Annual Credit Suisse Energy Summit

March 1, 2021

Cautionary Statements

Forward-Looking Statements: The data and/or statements contained in this presentation that are not historical facts are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, our ability to capitalize on emerging from bankruptcy and our ability to succeed on a long-term basis, the extent and length of the drop in worldwide oil demand due to the COVID-19 coronavirus, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected production levels, oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, the impact of regulatory rulings or changes, outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, and other variables surrounding operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; success of our risk management techniques; accuracy of our cost estimates; access to and terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, floods, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this presentation, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Statement Regarding CO_2 Storage Associated with EOR: Our CO_2 EOR operations provide an environmentally responsible method of utilizing CO_2 for the primary purpose of oil recovery that also results in the associated underground storage of CO_2. Any reference in this presentation to storage of CO_2 associated with our EOR operations is not meant to encompass CO_2 stored for the primary purpose of carbon sequestration.

Statement Regarding Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures including Adjusted EBITDAX. Any non-GAAP measure included herein is accompanied by a reconciliation to the most directly comparable U.S. GAAP measure along with a statement on why the Company believes the measure is beneficial to investors, which statements are included at the end of this presentation.

Note to U.S. Investors: Current SEC rules regarding oil and gas reserves information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2019 and December 31, 2020 were estimated by DeGolyer and MacNaughton, an independent petroleum engineering firm. In this presentation, we may make reference to probable and possible reserves, some of which have been estimated by our independent engineers and some of which have been estimated by Denbury's internal staff of engineers. In this presentation, we also may refer to one or more of estimates of original oil in place, resource or reserves "potential," barrels recoverable, "risked" and "unrisked" resource potential, estimated ultimate recovery (EUR) or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of resources that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Denbury Overview

A Unique Energy Business

- CO_2 Enhanced Oil Recovery (EOR) is our primary focus
- Low base decline rate and low capital intensity
- CO_2 expertise and assets position Denbury to lead in Carbon Capture, Use and Storage (CCUS)

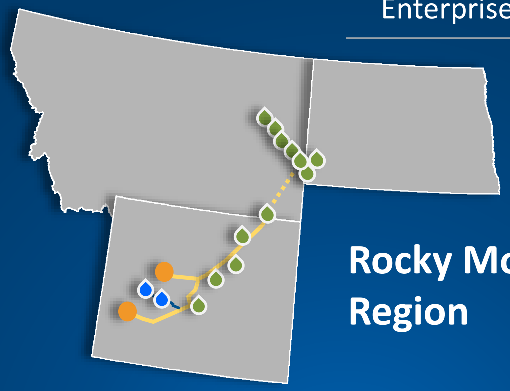
Fundamentally Geared to Crude Oil

- Industry-leading 97% oil production
- Superior crude quality (mid-30s API gravity, low sulfur)

Industry Leader in Reducing CO_2 Emissions

- Annually injecting ~3 million tons of industrial sourced CO_2 into our reservoirs
- Potential to reach full carbon neutrality this decade with CCUS, including downstream Scope 3 emissions

NYSE: **DEN**
Market Cap: **$2.1B**
Enterprise Value: **$2.3B**



4Q20 Production
48,805 BOE/d

YE20 Proved O&G Reserves
143 MMBOE

YE20 Proved CO_2 Reserves
5.7 Tcf

Strategically Advantaged Operations

- Vertically integrated CO_2 supply and distribution network with > 1,000 miles of CO_2 pipelines
- Cost structure largely independent from industry
- Asset base diversity mitigates single basin risk

Value Sustaining Organic Growth Upside

- Over 1 billion BOE proved + EOR and exploitation potential
- Ability to generate significant free cash flow at a low $40s oil price

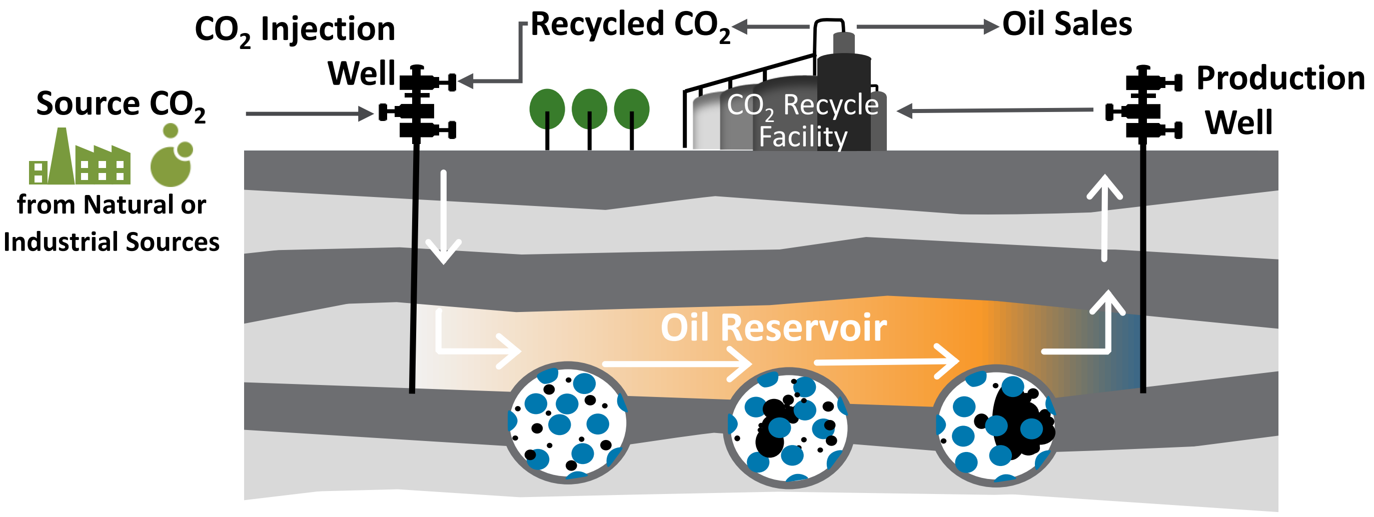
Positioned for the Future

- Delevered balance sheet provides significant flexibility
- Strategic focus aligned with the Energy Transition

The CO_2 EOR Process

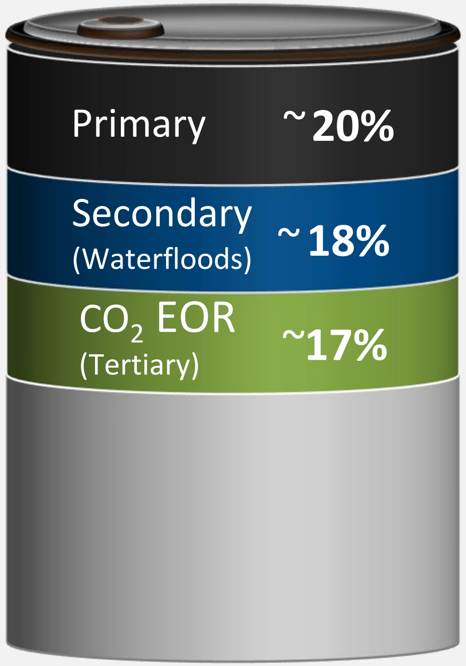
CO_2 Enhanced Oil Recovery (EOR) can produce nearly as much oil from a reservoir as was produced in either primary or secondary recovery

CO_2 EOR Process Overview



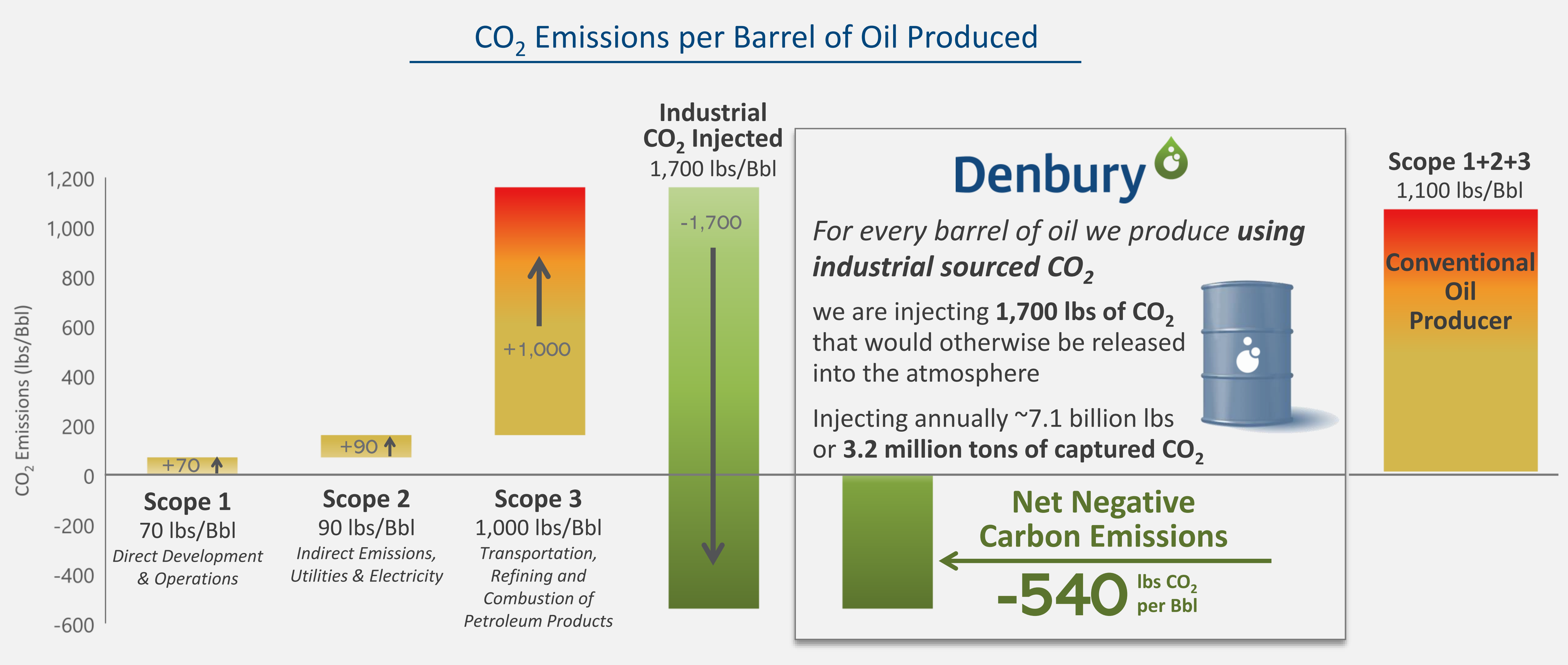
CO_2 is injected into the reservoir, moves through the reservoir, and combines with oil that it contacts	The CO_2/oil combination then continues moving through the reservoir and into nearby production wells	Once on the surface, the oil and CO_2 are separated, the oil is processed for sale and the produced CO_2 is recycled into the reservoir along with supplemental source CO_2	Nearly all of the source CO_2 volume associated with EOR operations ultimately remains in secure underground containment

Example Recovery of Original Oil in Place



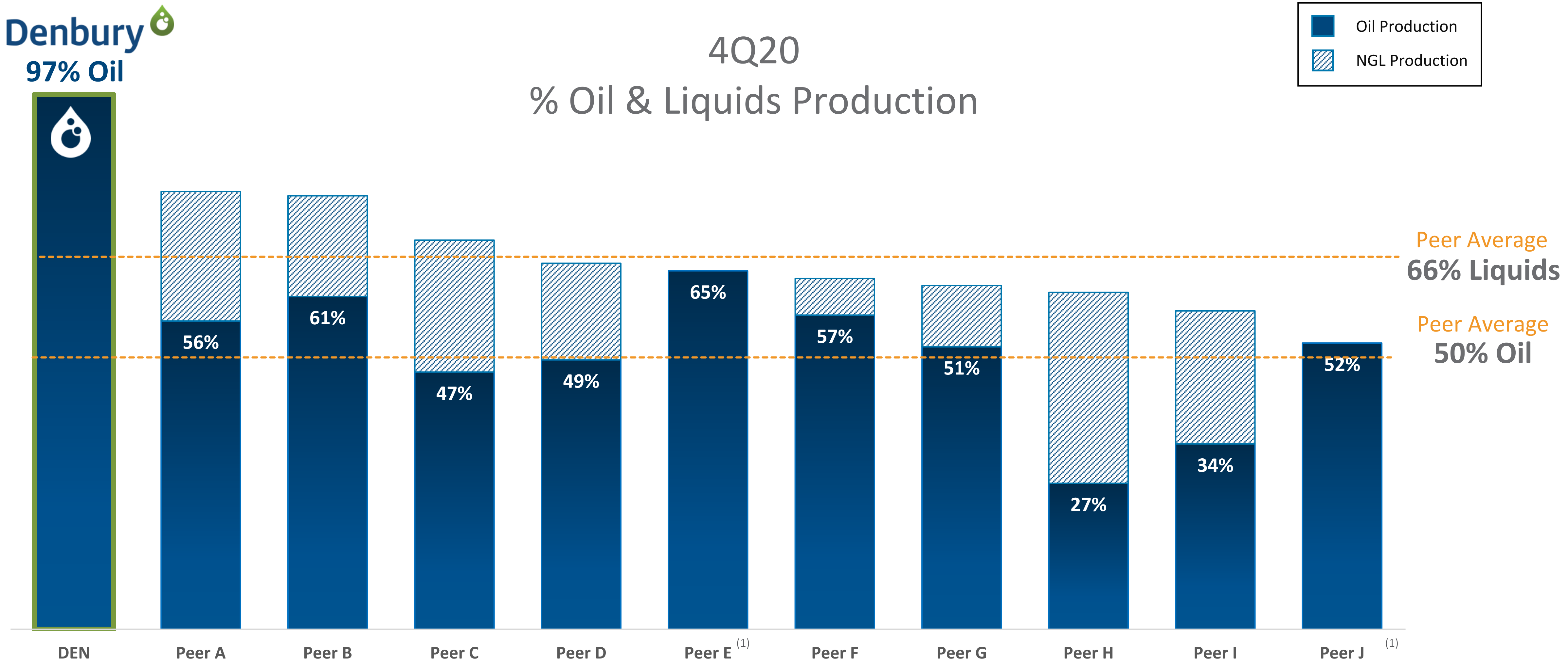
A Leading Producer of Low-Carbon Oil

~20% of Denbury's production is Scope 3 carbon negative through the use of industrial-sourced CO_2



Source: Clean Air Task Force, IEA and Denbury internal information.

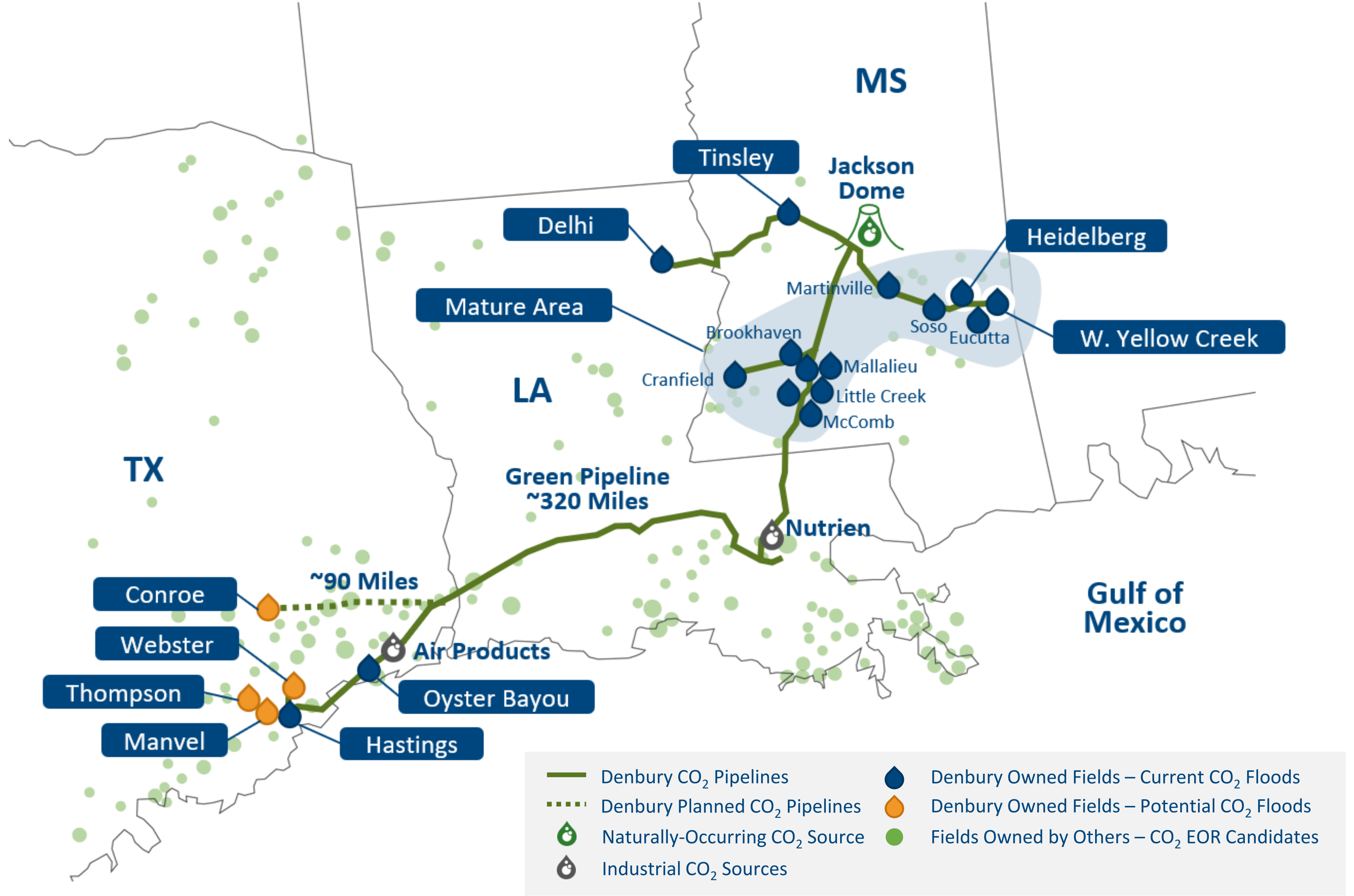
Industry-Leading Oil Weighting



Source: Peer filings for the fourth quarter ended 12/31/2020. Peers include CLR, DVN, LPI, MRO, MUR, OAS, PDCE, PXD, SM and WLL.

1) NGL production is not reported separately for this entity.

Gulf Coast Region



Note: See "Slide Notes" on slide 26 in the appendix to this presentation for footnote explanations.

YE20 Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	70
Potential	325
Non-Tertiary Reserves	
Proved	14
Total MMBOE[2]	**409**

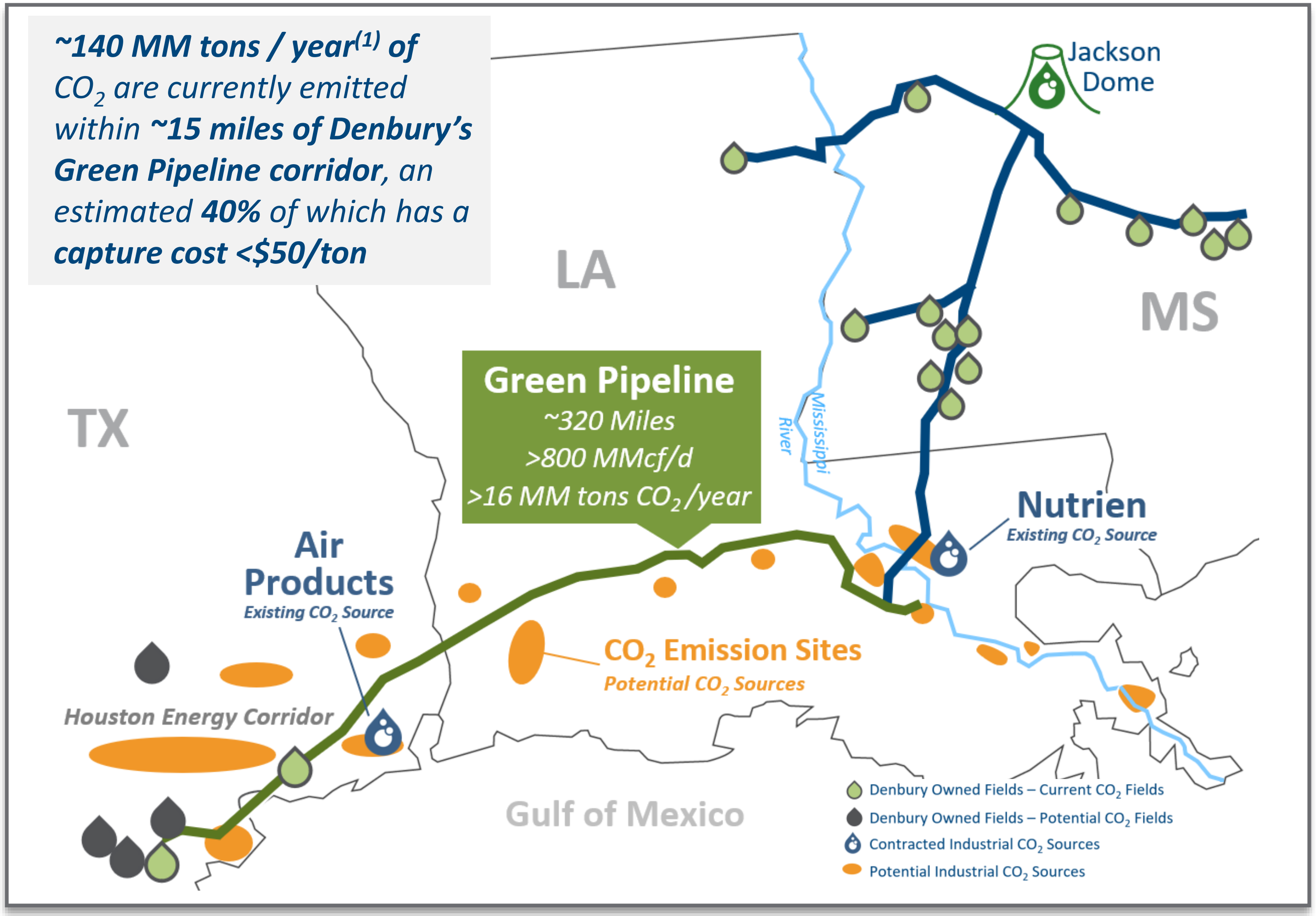
Proved + Tertiary Potential by Field[3]	
Mature Area	25
Conroe	130
Delhi	20
Hastings	30 – 65
Heidelberg	25
Manvel	10
Oyster Bayou	20
Tinsley	25
Thompson	20 – 40
Webster[4]	40 – 75
W. Yellow Creek	5

Strategically Positioned to Lead in CCUS

Gulf Coast pipeline network provides extensive framework for CCUS operations

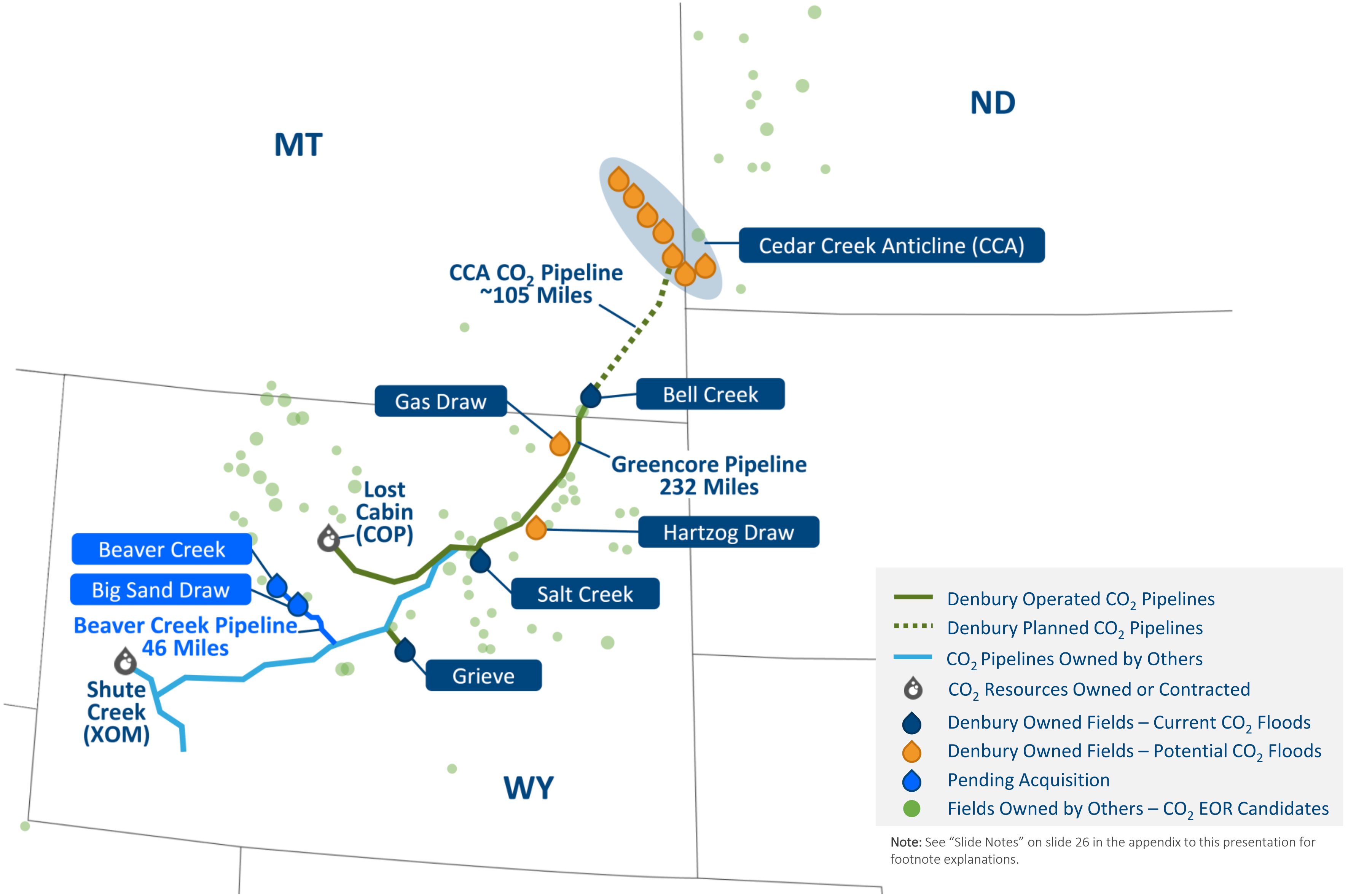
Gulf Coast Infrastructure Highlights

- Strategically located, 100% owned Green CO_2 pipeline along the Gulf Coast can transport >800 MMcf/d (>16 MM tons/year) of CO_2
- Extensive (~925 miles) pipeline network ideally suited for transporting captured CO_2 to either EOR or permanent storage sites
- Multiple CO_2 sources and EOR injection sites provide operational flexibility to ensure reliable CCUS operations



1) 2019 EPA Greenhouse Gas Reporting Program data.

Rocky Mountain Region



Note: See "Slide Notes" on slide 26 in the appendix to this presentation for footnote explanations.

YE20 Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	12
Potential	547
Non-Tertiary Reserves	
Proved	47
Total MMBOE[2]	**606**

Proved + Tertiary Potential by Field[3]	
Bell Creek	30
Cedar Creek Anticline Area	400 – 500
Gas Draw	10
Grieve	4
Hartzog Draw	30 – 40
Salt Creek	25 – 35

Pending Bolt-On Acquisition of Wyoming CO_2 EOR Fields

Supports Denbury's CO_2 EOR focused strategy, utilizing 100% industrial-sourced CO_2

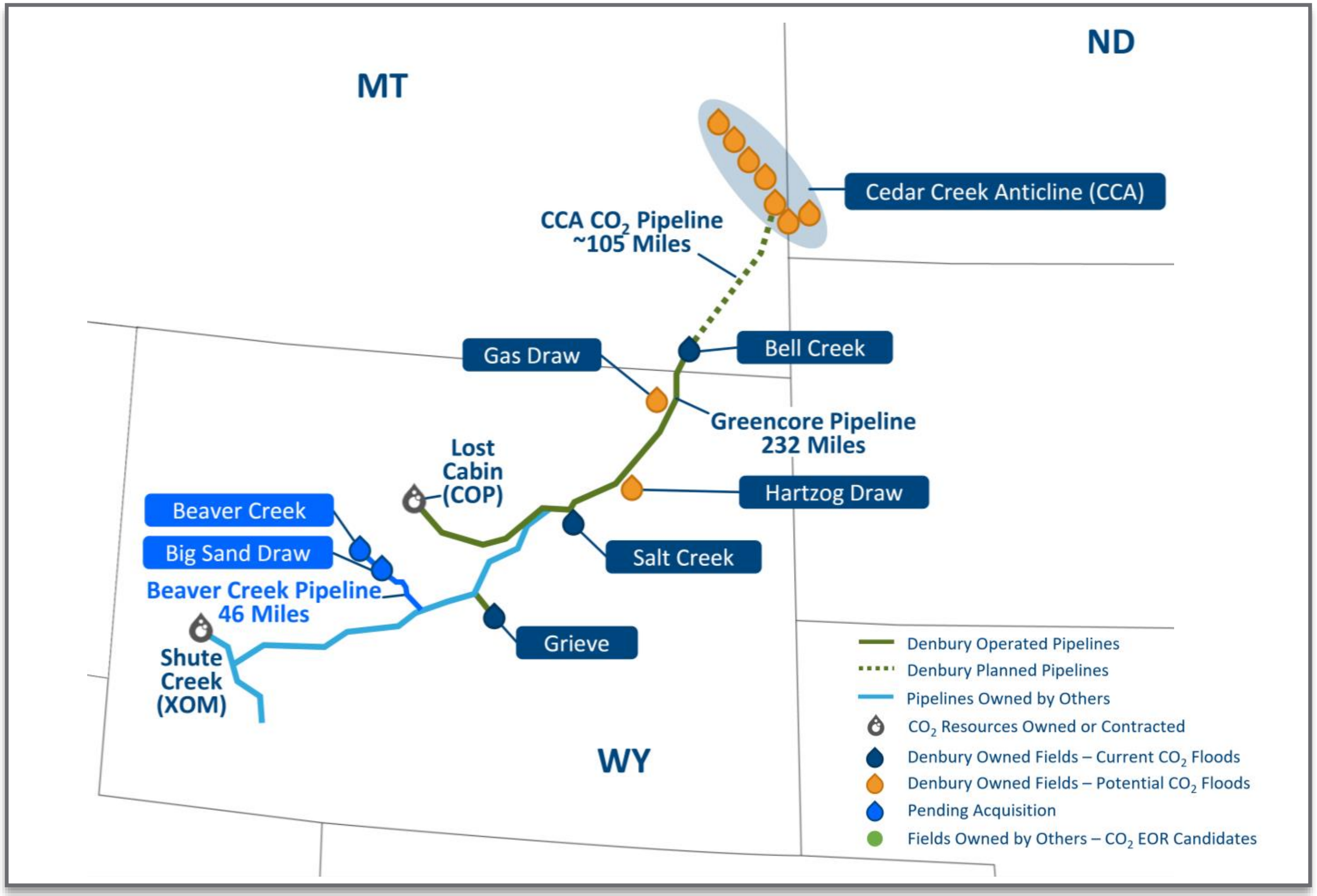
Beaver Creek / Big Sand Draw Oil Fields

Transaction Highlights

- $12 million purchase price includes 46-mile CO_2 pipeline
- Net proved reserves of ~13.7 MMBOE (93% oil), including 5.5 MMBOE of PUD reserves with est. development cost < $5/BOE
- Annually utilizes nearly 400,000 tons of industrial-sourced CO_2

Additional Details

- ~100% working interest and ~83% net revenue interest
- Agreement provides for two contingent payments of $4MM each in 2021 and 2022 if NYMEX WTI oil price averages at least $50/Bbl in those calendar years
- 3Q 2020 net production ~2,800 BOE/d (85% oil)
- Expect to close acquisition in 1Q 2021



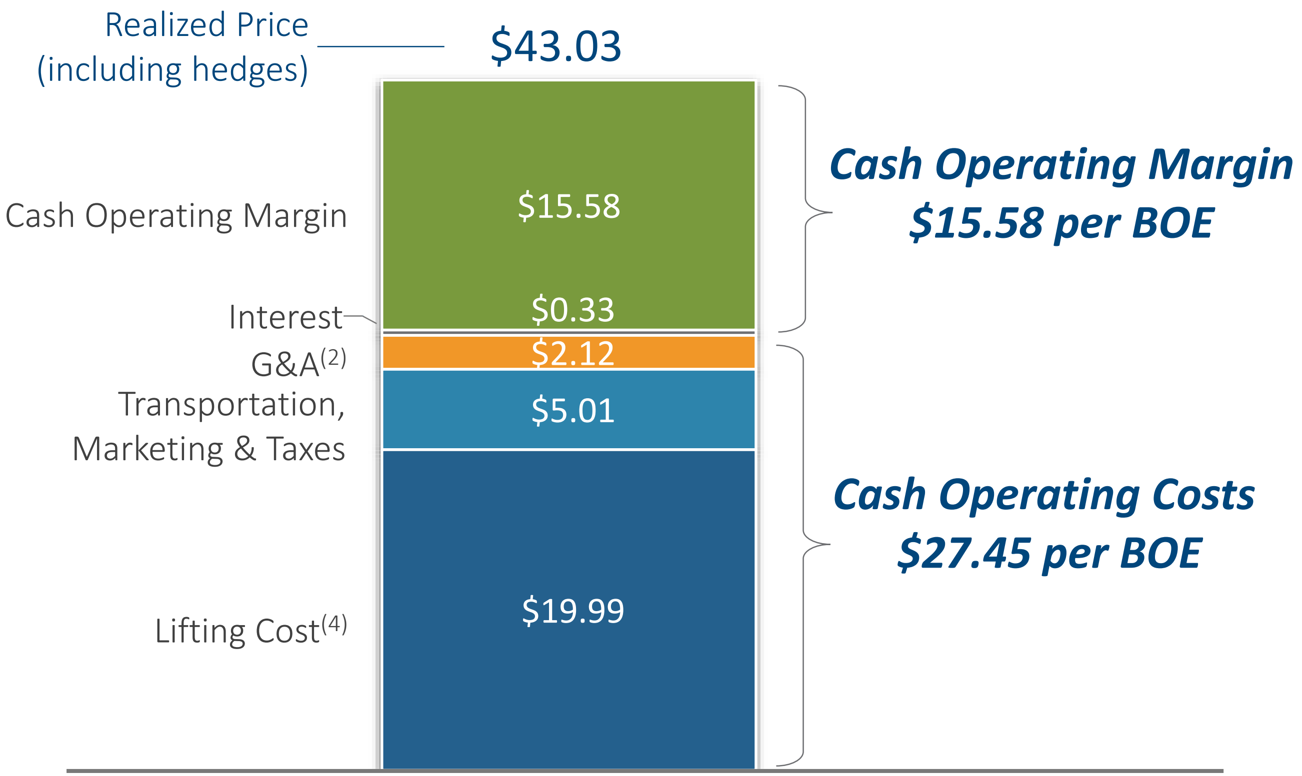
2020 Highlights & Results

Highlights and Accomplishments

- ☑ Achieved record levels of safety performance for the fourth consecutive year
- ☑ Executed agreement for bolt-on acquisition of EOR assets in Rocky Mountain Region
- ☑ Reacquired NEJD and Free State CO_2 pipelines
- ☑ Received $29 million of proceeds from the sale of Houston area surface acreage in 2020
- ☑ Reduced annual lifting cost to $19.60/BOE[3], the lowest in 4 years in response to low oil prices
- ☑ Exercised capital discipline and optimized production to complete year within revised guidance ranges
- ☑ Successfully restructured balance sheet

4Q20 Operating Margin ($/BOE)[1]

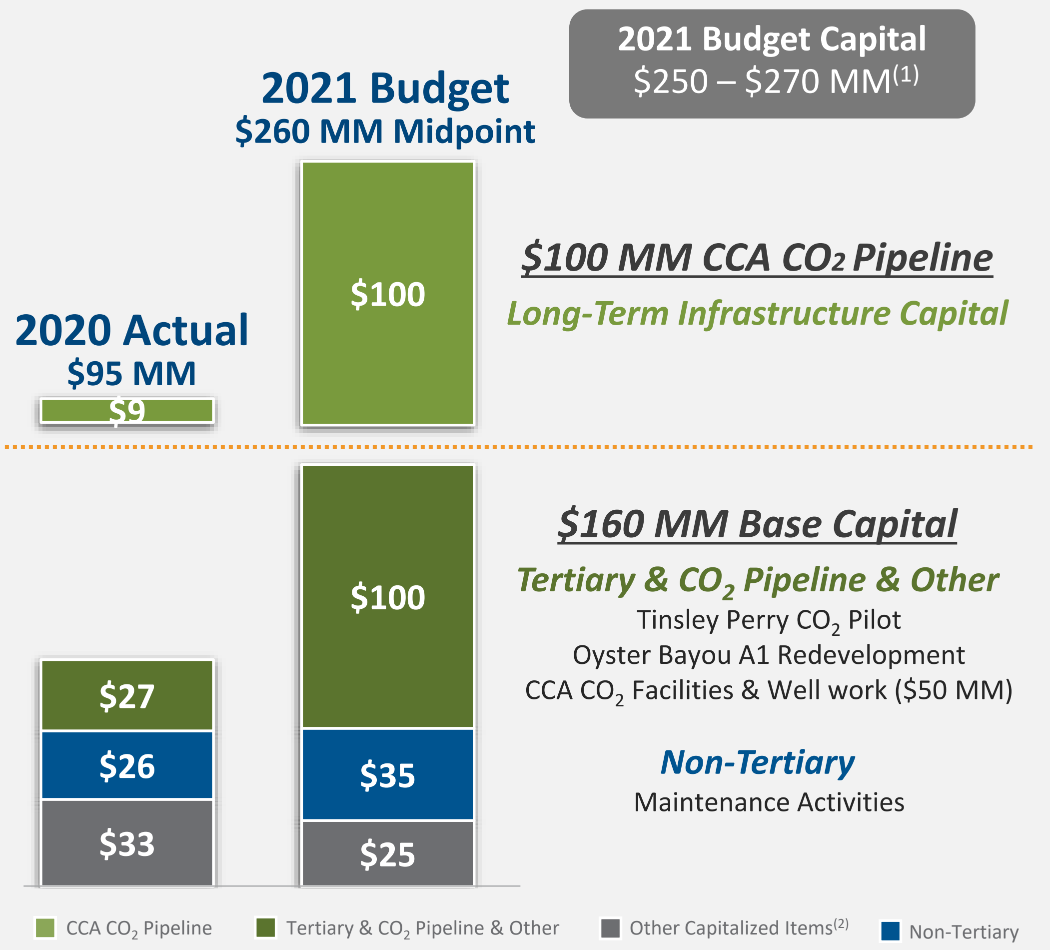
36% Cash Operating Margin



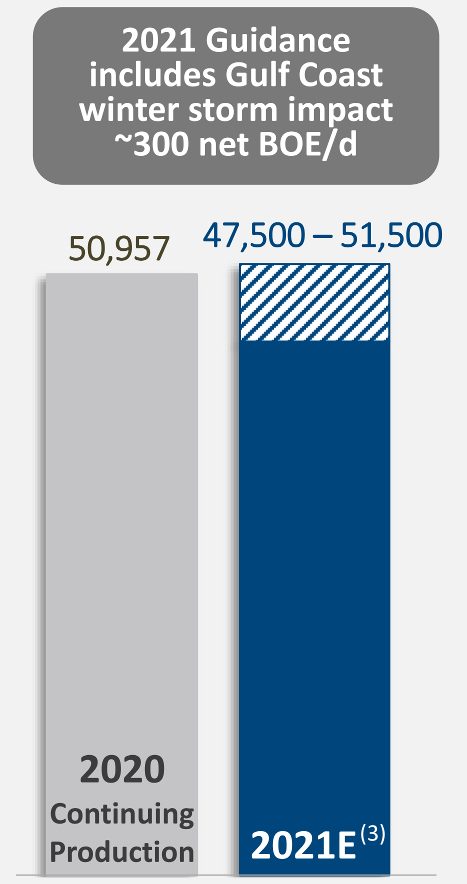
1) Excludes selected items of other expense and CO_2 operating margin.
2) G&A excludes non-cash compensation of approximately $8 million ($1.83/BOE).
3) Normalized lifting cost, excluding the insurance settlement reimbursement of $15 million related to 2013 well incident in the Delhi field. See slide 36 for a detail of operating expenses.
4) See slide 36 for a detail of operating expenses.

2021 Estimated Capital, Production and Cash Flow

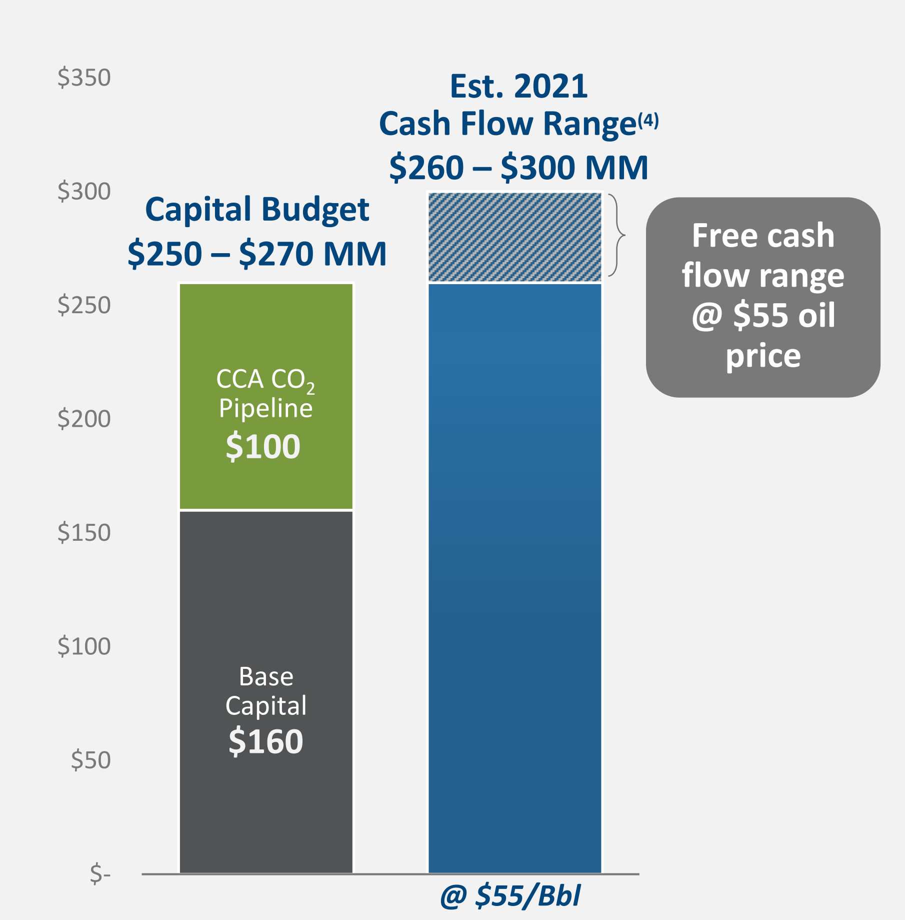
Capital ($MM)



Production (BOE/d)



Cash Flow Range ($MM)



1) Amounts presented exclude $5 - $7 million of capitalized interest.
2) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.
3) Includes anticipated production from the Big Sand Draw and Beaver Creek oil fields beginning in early March 2021.
4) Cash flow before working capital changes, including hedges. Currently estimated ranges based upon assumed $55/Bbl NYMEX oil prices, forecasts and assumptions as of February 25, 2021. See press release attached as exhibit 99.1 to the Form 8-K filed February 25, 2021 for additional information indicating why the Company believes this non-GAAP measure is useful to investors.

Cedar Creek Anticline – A World Class CO_2 EOR Project

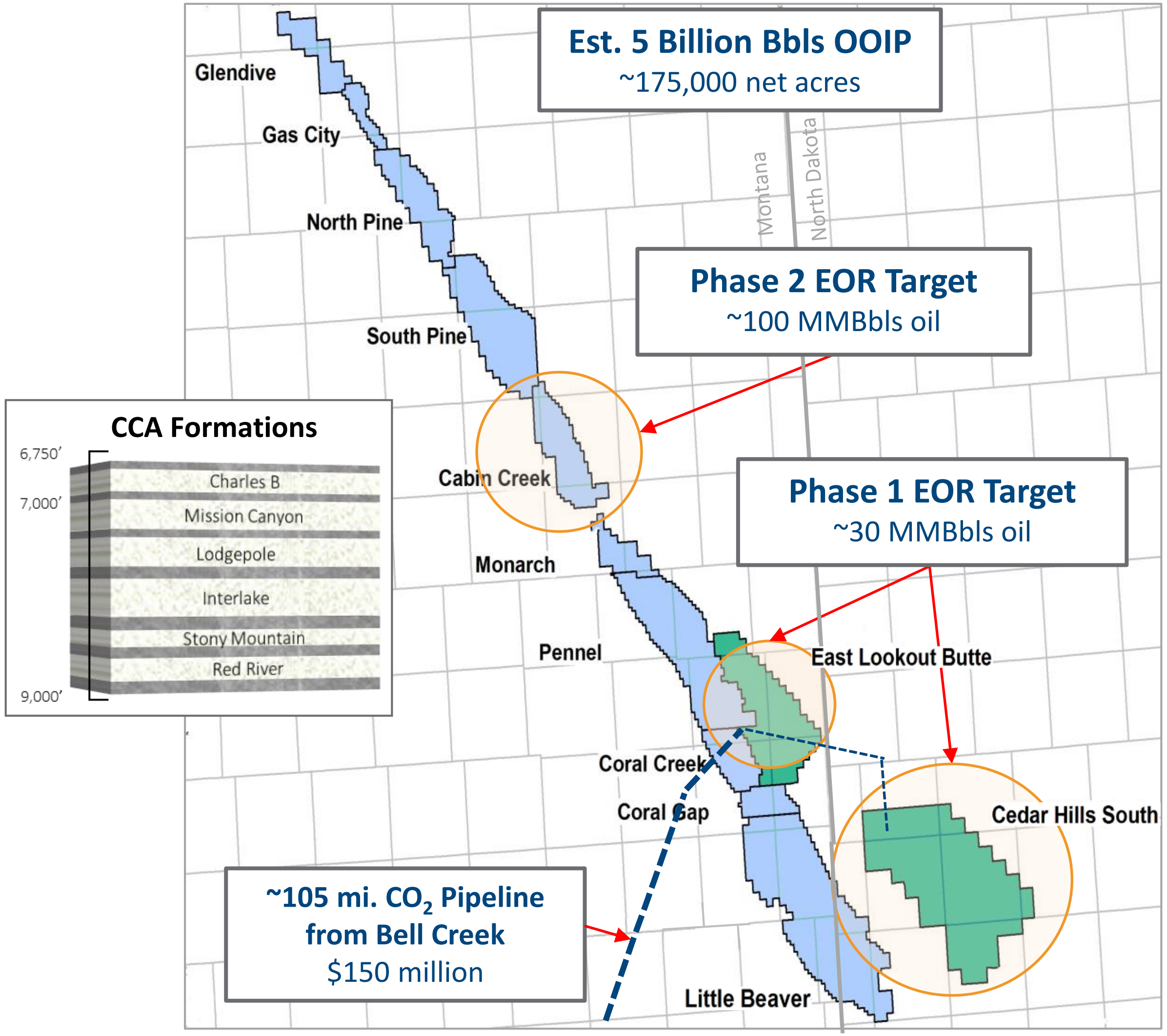
> 400 MMBbl total recovery potential using 100% industrial-sourced CO_2

CO_2 Pipeline to CCA from Bell Creek
- Plan to install in 2H 2021; ~$100 MM anticipated 2021 capital spend
- Services all CCA EOR development phases; represents < $0.50/Bbl across total project
- All key permits in place

Phase 1
- Targets ~30 MMBbls of recoverable oil in Red River formation in East Lookout Butte and Cedar Hills South
- First production expected in 2H23
- Total capex (excl. CO_2 pipeline) ~$500 MM over 15 years

Phase 2
- Targets ~100 MMBbls of recoverable oil in Interlake, Stony Mountain and Red River formations in Cabin Creek
- Development expected to commence in 2024
- Total capex of ~$500 – $600 MM over multiple decades

Future Phases – Remainder of CCA
- > 300 MMBbl EOR potential in multiple formations



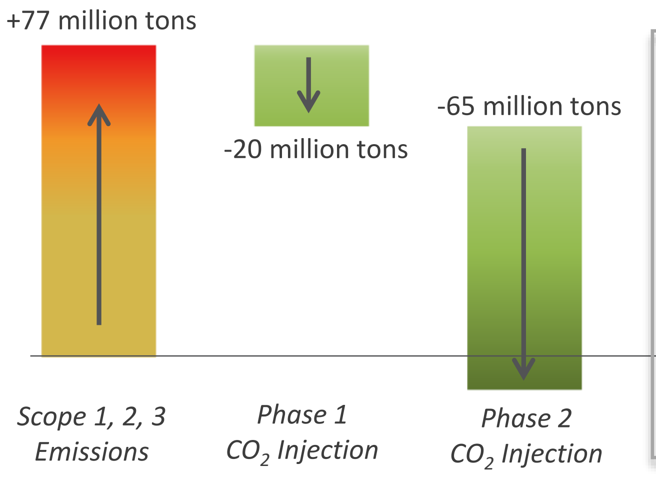
CCA EOR – A Scope 3 Carbon Negative Development

Phases 1 & 2 will collectively store ~85 million metric tons of industrial-sourced CO_2

Additional Development Details

- Evaluating further enhancements to project based on potential availability of additional CO_2
- Evaluating financing alternatives for the CO_2 pipeline construction
- Anticipated $10-15/Bbl Phase 1 and 2 tertiary lifting cost expected to meaningfully reduce overall corporate LOE/BOE

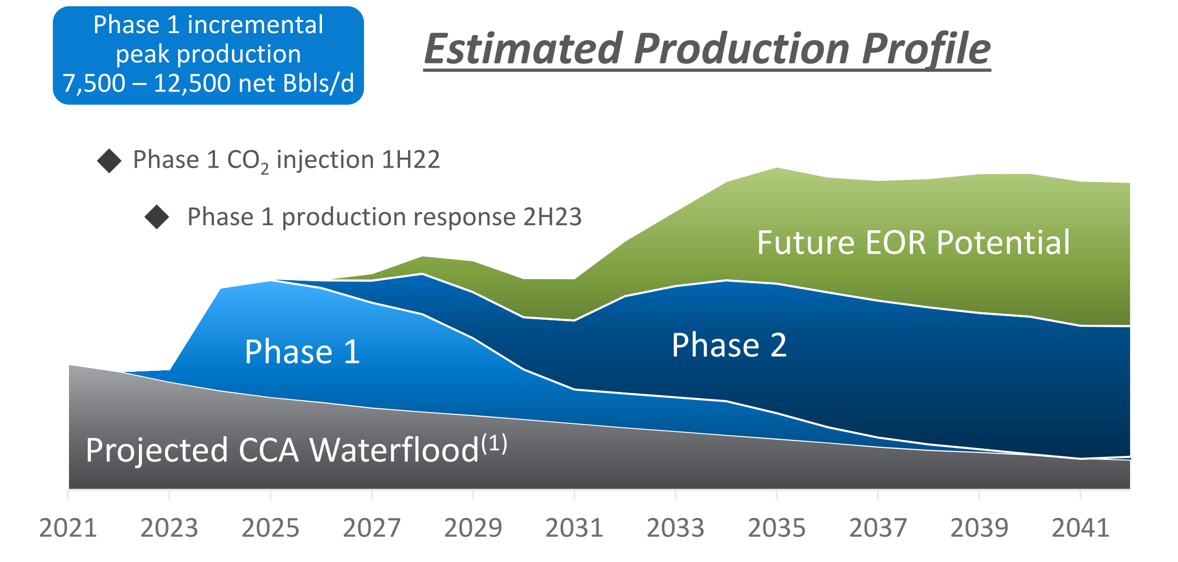
CO2 Emissions – Scope 3 Negative

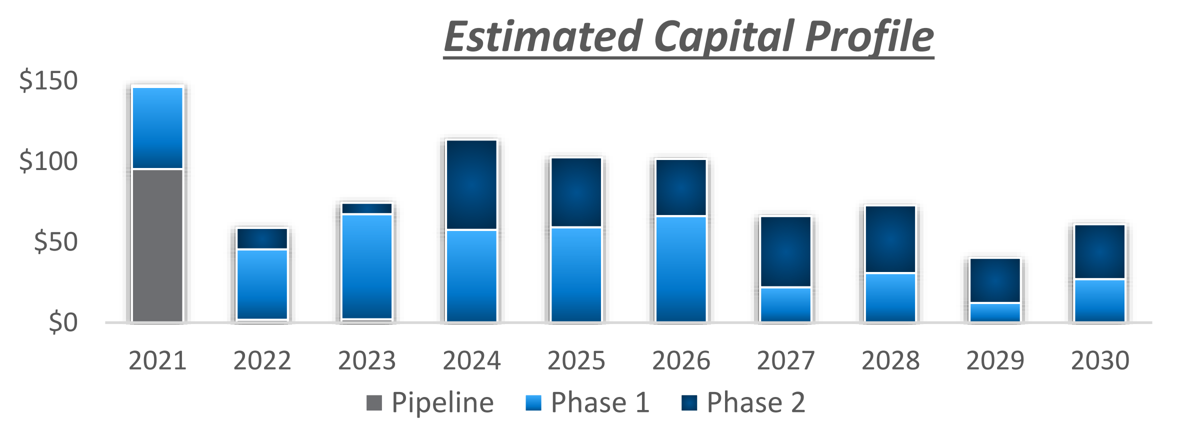


CCA EOR Development utilizes 100% industrial-sourced CO_2

-8 million tons

Net Negative Carbon Emissions





1) CCA waterflood proved production profile at $50/Bbl NYMEX

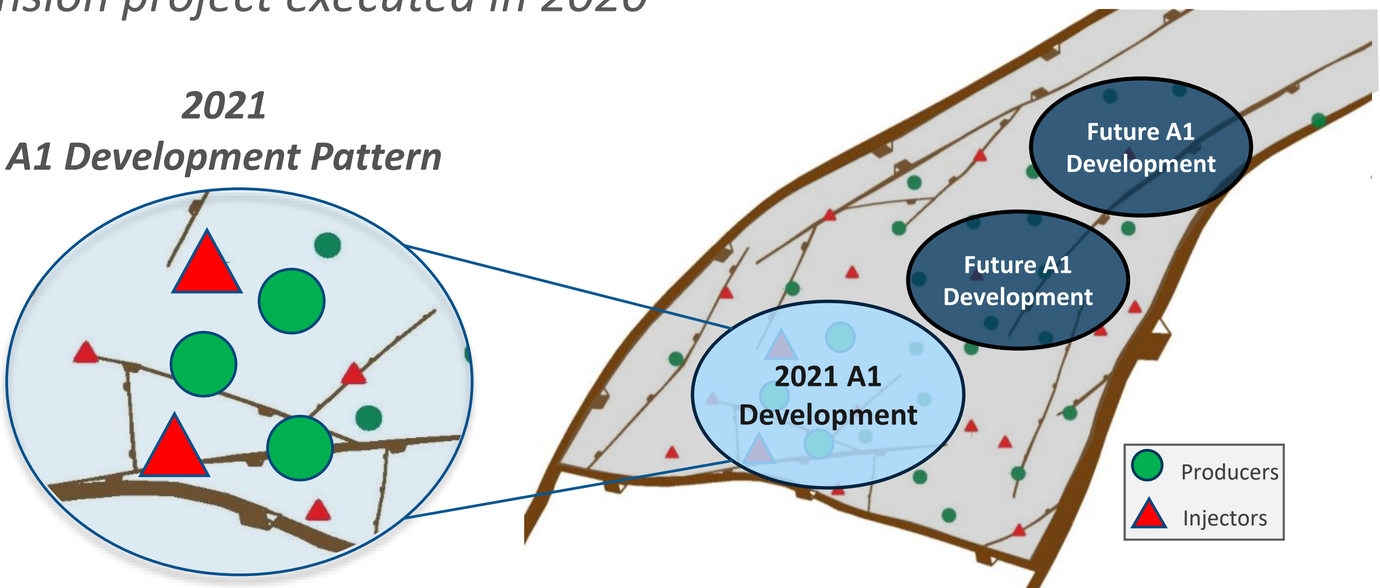
2021 Tertiary Capital - Oyster Bayou A1 Development Expansion

Continues success from A2 Development Expansion project executed in 2020

Development Overview

- A1 Development Expansion
  - 3 development areas, expands upon successful in-field analogs
  - Targets A1 Lower reservoirs
- 2021 capital spend ~$5 million
  - 2 producer conversions, 1 new drill producer and 2 injector conversions
- Project scheduled to begin 1Q21
- Future Development
  - Additional opportunities in A1 and A2 reservoirs

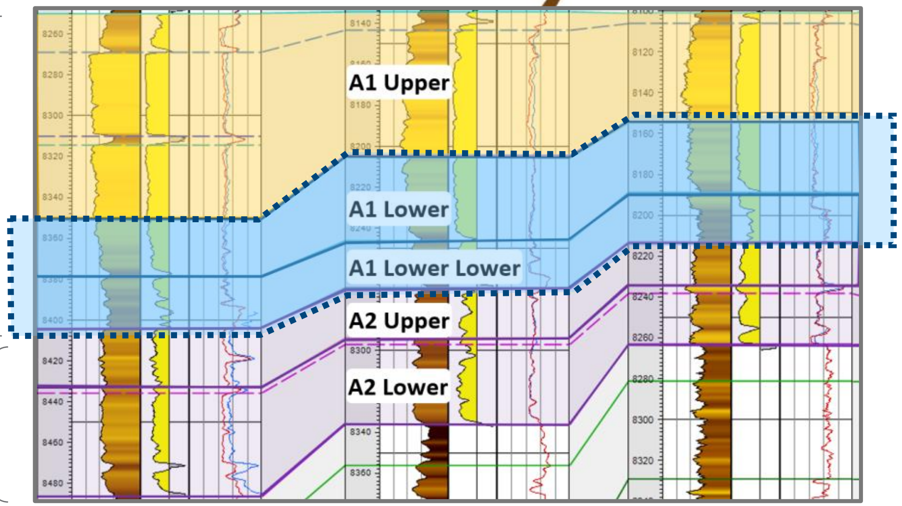
2021
A1 Development Pattern



Producing zone in other phases

2021
Development Expansion targeting A1 reservoir

2020
Development Expansion targeting A2 reservoir

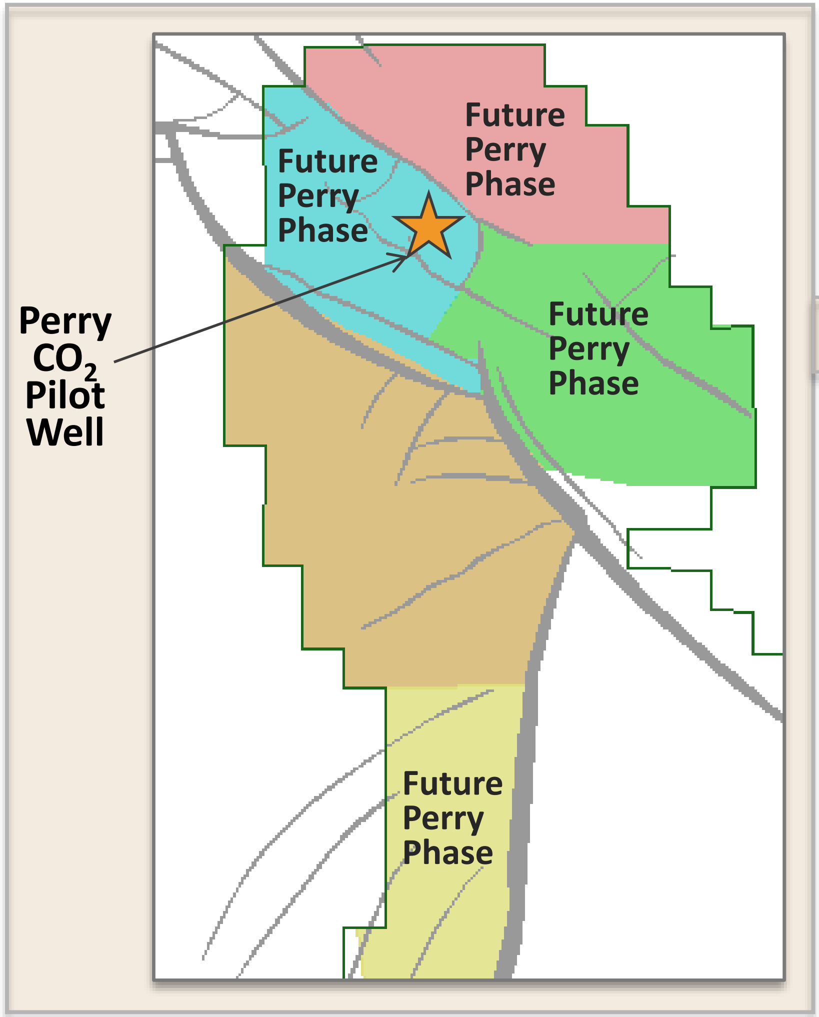


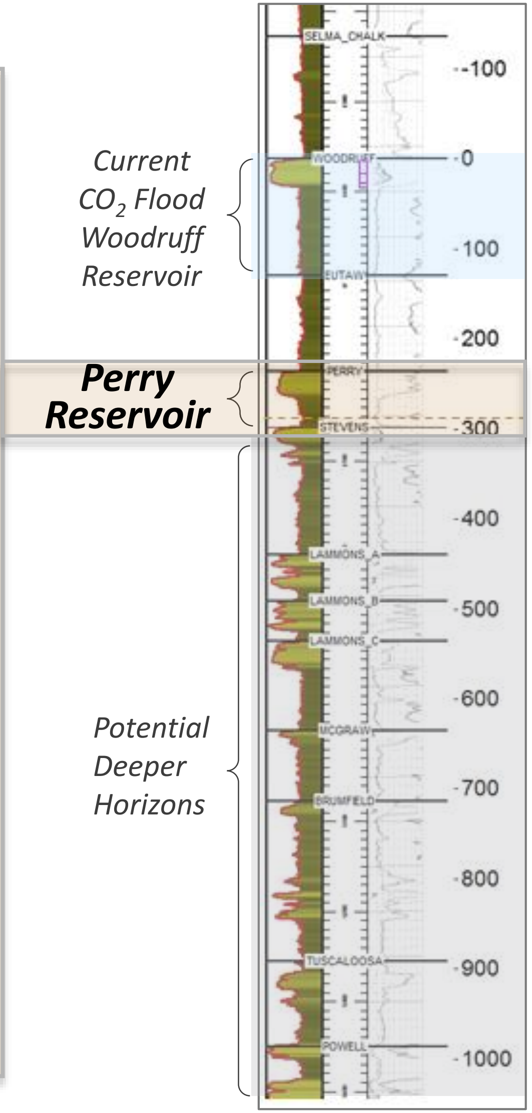
2021 Tertiary Capital – Tinsley Perry CO_2 Pilot

2021 Pilot unlocks development target of > 10 MMBbls

Development Overview

- New CO_2 flood in Tinsley
  - Targets high residual oil saturation
  - Horizontal development to achieve higher reservoir processing rates
  - Leverages Tinsley's existing CO_2 infrastructure
- 2021 capital spend ~$7 MM
  - 1 new horizontal producer, 1 horizontal injector conversion and 2 recompletions
- Project scheduled to begin 1Q21
- Future Development
  - 4 phases, ~20 horizontal wells
  - Opportunity for multi-year phased development

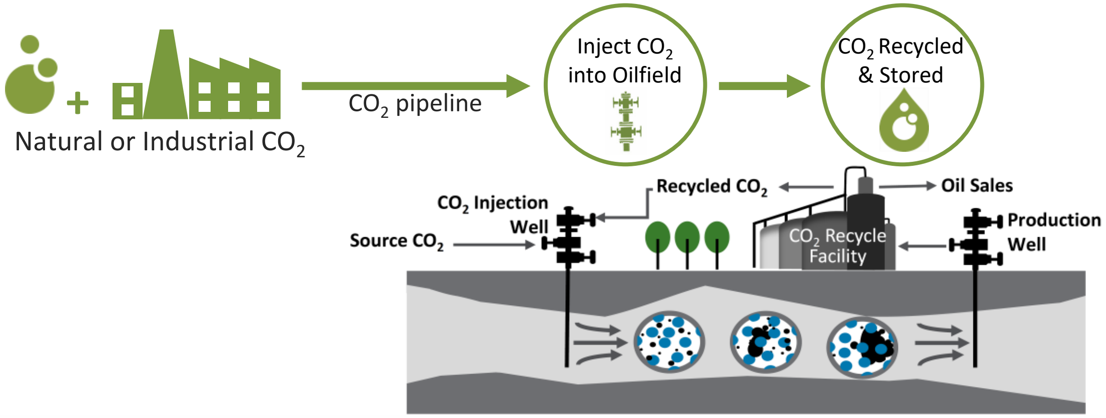




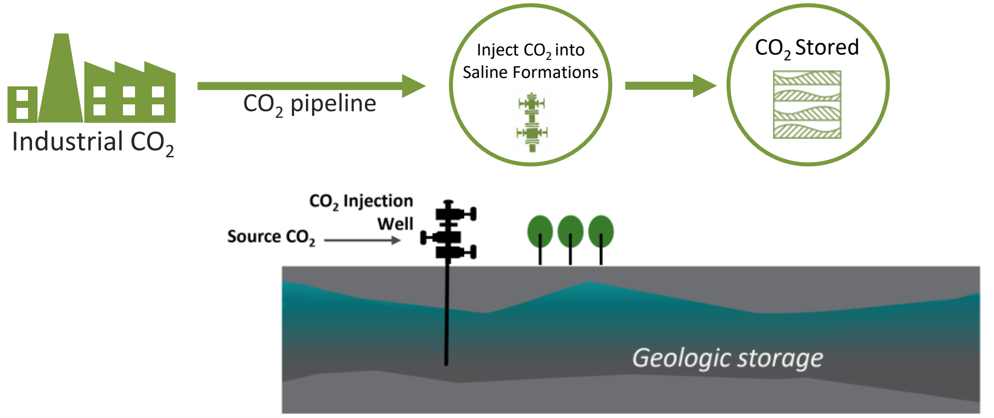
Carbon Capture, Use and Storage (CCUS) Overview

CCUS – both through CO_2 EOR or direct CO_2 injection – is a proven technology with the potential for safe, long-term, deep underground containment of billions of tons of industrial-sourced CO_2

CO_2 Stored in Association with EOR



CO_2 Directly Stored



A proven process

CCUS is an effective, low cost solution using existing, proven processes and technology

Experience gained from decades of safe CO_2 EOR operations translates directly into safe CCUS operations

Reduces atmospheric CO_2

CCUS has the potential to drive a significant reduction in atmospheric CO_2 emissions

The NPC's 2019 CCUS report identified a reasonable path where the volume of CO_2 captured in the U.S. would increase over the next 15 years to ~150 million tons per year, >500% above current levels

Supported by government policy

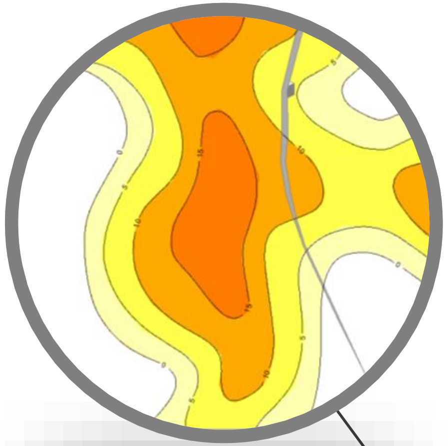
CCUS policy has bipartisan support and is critical to providing the economic and legal framework for investment in CCUS projects

The 45Q tax credit structure provides the capturing parties a tax credit of \$35/ton for CO_2 used in EOR operations and \$50/ton for CO_2 directly stored in geologic formations

Source: National Petroleum Council (NPC) 2019 Report, Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage.

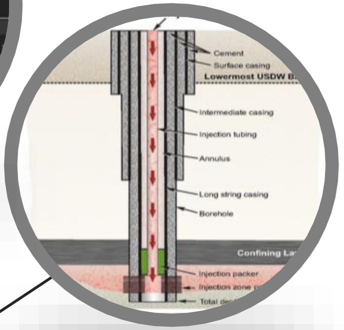
Denbury's Extensive CO_2 Experience is Ideally Suited for CCUS

Over 20+ years, we have transported and injected a combined ~185 million metric tons of natural and industrial CO_2



Geologic Site Characterization

- Detailed analysis and modeling to ensure suitability of target reservoirs for long-term containment of injected CO_2

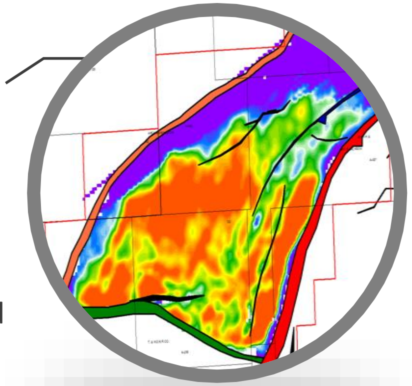


Secure Wellbore Design & Advanced Monitoring

- Wellbores constructed to isolate targeted formations and protect freshwater with emphasis on corrosion prevention, detection, and mitigation
- Routine temperature logging to verify behind-pipe integrity
- Leveraging automated data collection to quickly identify and respond to unexpected conditions
- Enhanced well plugging criteria applied to all abandoned wells to ensure secure CO_2 containment

Subsurface Surveillance

- 4D seismic imaging to aid in observation of CO_2 placement and conformance
- Sophisticated well logging
- Extensive use of fluid sampling and tracers
- Reservoir simulation modeling



CO_2 Handling & Processing Expertise

- Processing over 3.5 billion cubic feet (180,000 metric tons) of CO_2 per day
- Proven expertise in designing, building, and operating CO_2 pipelines, processing facilities, and gathering/distribution systems

An Industry Leader in Reducing CO_2 Emissions

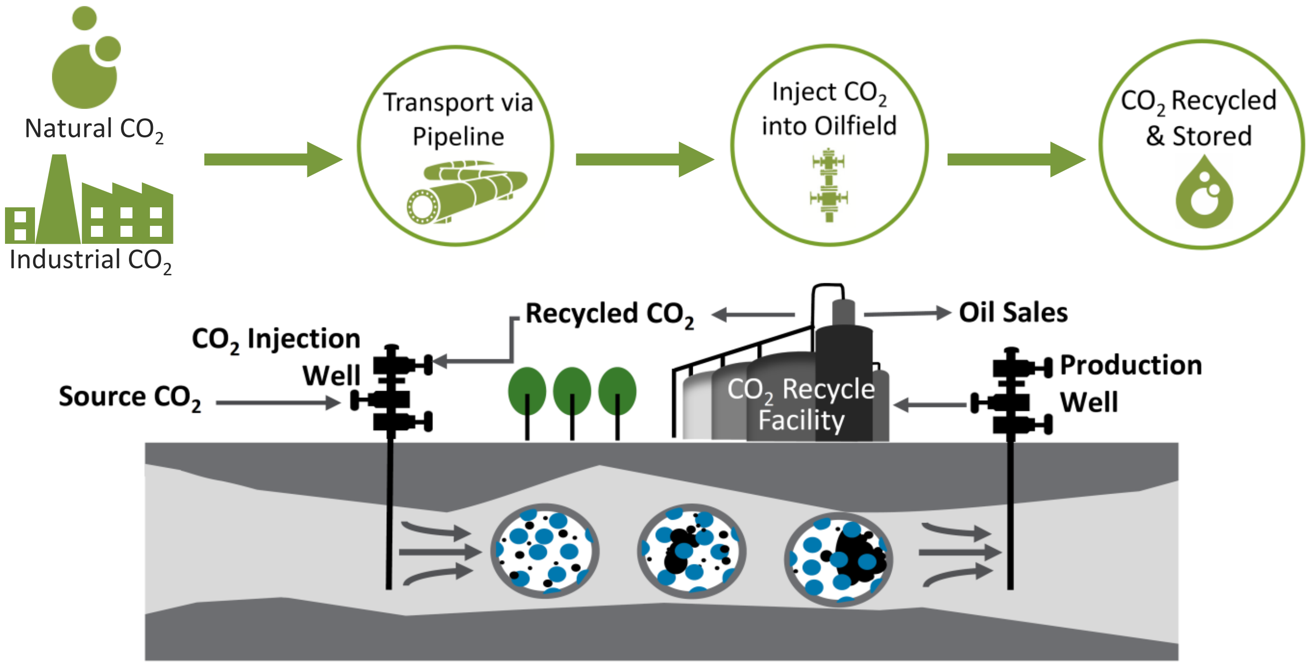
Environment

The only U.S. public company of scale where injecting CO2 into the ground to produce oil is our primary business

Combined Scope 1 and Scope 2 CO_2 Emissions Net Negative

Average of 2018 and 2019

Combined Scope 1 & 2 Emissions		*Captured Industrial-Sourced CO_2*		*Net Negative CO_2 Emissions*
1.8 million metric tons	**–**	**3.2 million metric tons**	**=**	**– 1.4 million metric tons**



~30% of our CO_2 is industrial sourced

We utilized **3.2 million metric tons** (2018-2019) of industrially sourced CO_2 that could otherwise have been released into the atmosphere

CO_2 **=** Annual greenhouse gas emissions from almost **700,000** cars

Strong Corporate Governance

Governance

Strong corporate governance is essential to fulfilling our obligations to our stakeholders and to operating as a responsible corporate citizen

- **6 out of 7** directors are independent, including independent Chairman of the Board
- Long-standing **female board representation** since 2012
- ISS Governance **Rating of "1"** (top ranking)
- **Code of Conduct and Ethics Rated "A"** by NYSE Governance Services (Top 1%)
- Recently formed a **Sustainability Committee** of the Board of Directors

Dr. Kevin Meyers
Director Since 2011
Chairman of the Board, Compensation and Sustainability Committee

Chris Kendall
Joined Denbury in 2015
Director, President and Chief Executive Officer

Lynn Peterson
Director Since 2017
Nominating/Corporate Governance, Audit and Sustainability Committee*

Anthony Abate
New Director 2020
Audit and Compensation Committee*

Caroline Angoorly
New Director 2020
Sustainability and Nominating/Corporate Governance Committee*

James Chapman
New Director 2020
Compensation and Nominating/Corporate Governance Committee*

Brett Wiggs
New Director 2020
Audit Committee

See full biographies for the Board Members at www.denbury.com

*Reflects Committee Chairperson

Committed to Operating Safely and Responsibly

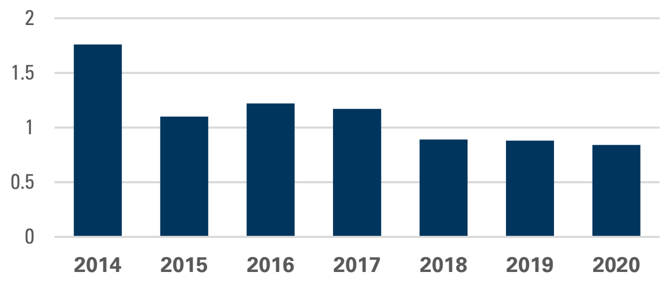
Social

We maintain a long-standing commitment to the highest standards for the safety and development of our employees, contractors and local communities

- **Achieved our best** Total Recordable Incident Rate (**TRIR**) **in 2020**
- **Executive compensation** is explicitly **tied to safety targets**
- **Comprehensive training and development program** including safety, leadership, and diversity training
- **Matched >$250,000 employee charitable donations** over last 6 years
- CEO is the 2020/2021 **Chair of Dallas Board of the American Heart Association**

LIVE SAFE ZERO BY CHOICE

Total Recordable Incident Rate (TRIR)



Recipient of the 2018
Excellence in Safety Award
by North Dakota Petroleum Council

DOING RIGHT

Consistent sustainability reporting (2014-2019) in accordance with GRI Standards.
Our most recent Corporate Responsibility Report can be accessed on our website at: ***csr.denbury.com***

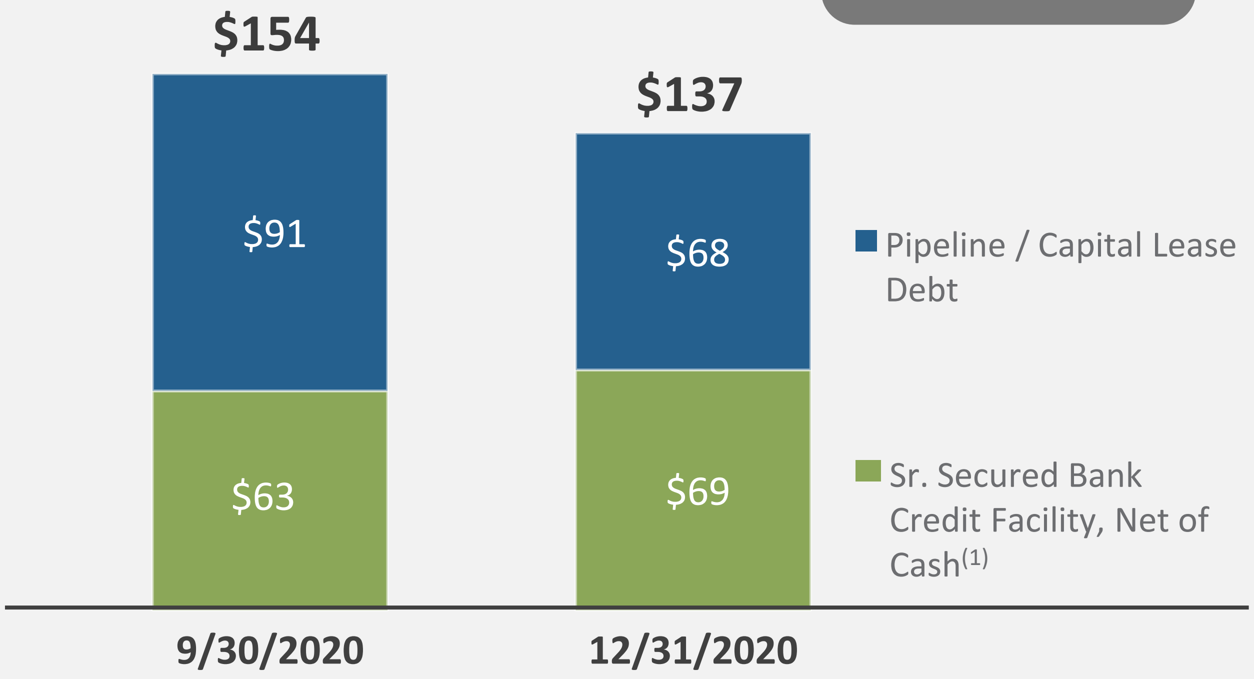
Debt Profile and Liquidity

Leverage ratio of 0.4x at year-end 2020

Net Debt

(In millions, unless otherwise noted)

$482 million of availability under Bank Credit Facility at 12/31/20



Credit Facility Overview

Sr. Secured Bank Credit Facility

- $575 million borrowing base
- $482 million availability at December 31, 2020
  - $70 million drawn
  - $23 million of letters of credit issued
- Semi-annual redeterminations beginning May 1, 2021
- Maturity Date: January 30, 2024
- Financial Covenants:
  - Total Debt / EBITDAX: < 3.50x at the end of each quarter
  - Current Ratio: > 1.00x at the end of each quarter

1) Sr. Secured Credit Facility borrowings are net of cash of $22 million at September 30, 2020, and $0.5 million at December 31, 2020.

Hedge Portfolio – As of February 24, 2021

			2021						2022	
			Jan	Feb	Mar	2Q	3Q	4Q	1H	2H
Fixed Price Swaps	**WTI NYMEX**	***Volumes Hedged (Bbls/d)***	***26,000***	***27,000***	***29,000***	***29,000***	***29,000***	***29,000***	***9,500***	***1,000***
		Swap Price[1]	42.54	42.96	\$43.86	\$43.86	\$43.86	\$43.86	\$44.24	\$50.13
Collars	**WTI NYMEX**	***Volumes Hedged (Bbls/d)***	***3,000***	***4,000***	***4,000***	***4,000***	***4,000***	***4,000***	***1,000***	***1,000***
		Floor Price[1]	45.00	46.25	\$46.25	\$46.25	\$46.25	\$46.25	\$47.50	\$47.50
		Ceiling Price[1]	50.95	53.04	\$53.04	\$53.04	\$53.04	\$53.04	\$53.00	\$53.00
	Total Volumes Hedged		**29,000**	**31,000**	**33,000**	**33,000**	**33,000**	**33,000**	**10,500**	**2,000**
	% of 2021 Guidance Midpoint Volumes (BOE/d)		**59%**	**63%**	**67%**	**67%**	**67%**	**67%**	**21%**	**4%**

1) Averages are volume weighted.

Our Vision

To be recognized as the world leader in CO_2 Enhanced Oil Recovery, significant in scale, financially secure, and strategically positioned through our expertise and our assets to lead the industry in the emerging Carbon Capture, Use and Storage (CCUS) business

Appendix

Slide Notes

Slide 7 – Gulf Coast Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/20 SEC pricing ($39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas). Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/19, using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.
4) Potential tertiary oil reserves represent 100% of Denbury's current working interest in Webster. Any future tertiary development would be subject to elective partner participation that would result in a reduction of Denbury's current working interest.

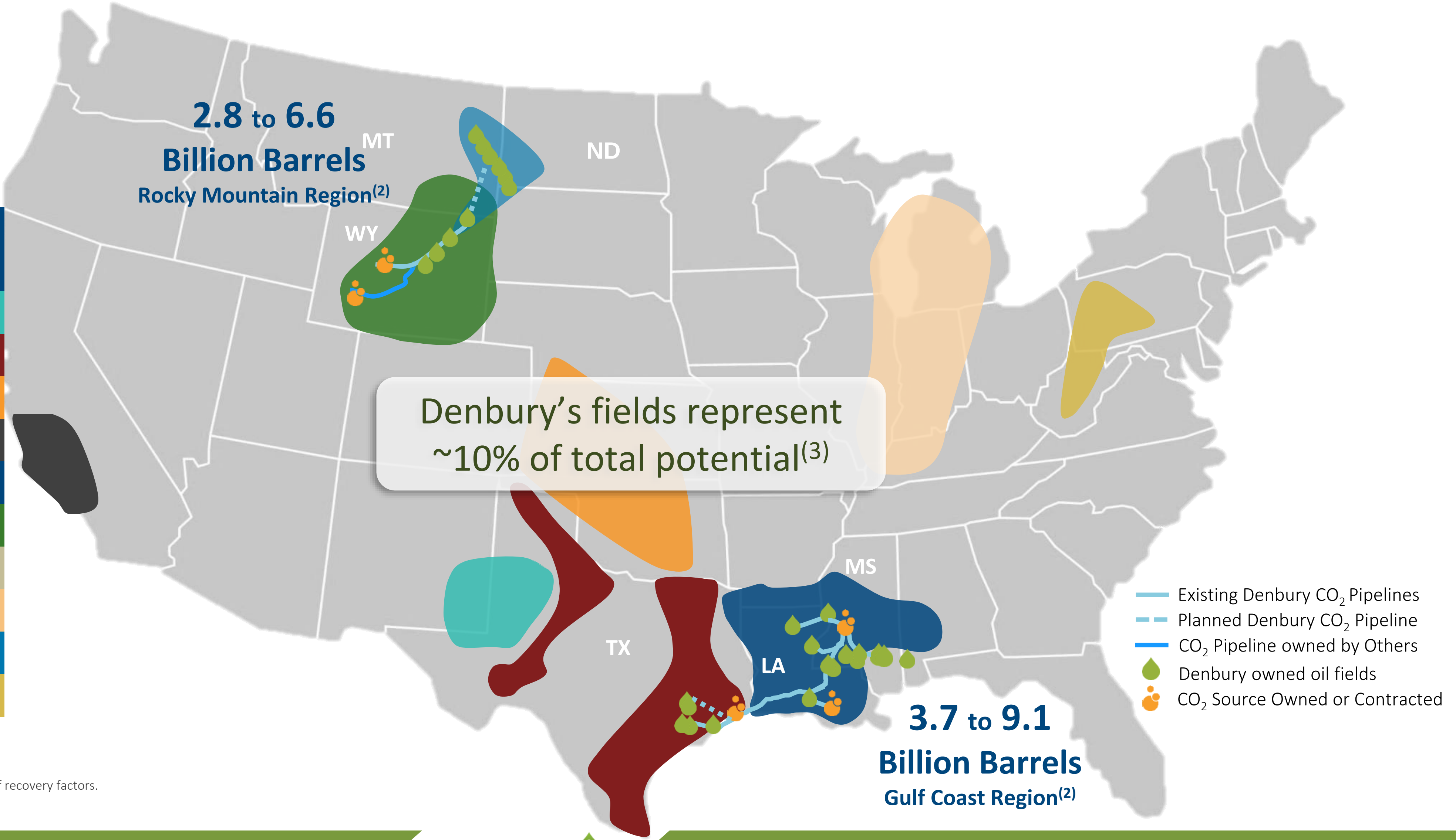
Slide 9 – Rocky Mountain Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/20 SEC pricing ($39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas). Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/19, using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.

Significant CO_2 EOR Potential in the U.S.

Denbury's assets and pipeline infrastructure are well positioned in key EOR potential basins

33-83 Billion Barrels of Technically Recoverable Oil[1,2]	
Permian	9-21
East & Central Texas	6-15
Mid-Continent	6-13
California	3-7
South East Gulf Coast	3-7
Rockies	2-6
Other	0-5
Michigan/Illinois	2-4
Williston	1-3
Appalachia	1-2



1) Source: 2013 DOE NETL Next Gen EOR.
2) Total estimated recoveries on a gross basis utilizing CO2 EOR.
3) Using approximate mid-points of ranges, based on a variety of recovery factors.

CO_2 EOR is a Proven Process

Significant CO_2 EOR Operators by Region

Gulf Coast Region	
» Denbury	» Hilcorp
Permian Basin Region	
» Occidental	» Kinder Morgan
Rocky Mountain Region	
» Denbury	» FDL
» Devon	» Chevron
Canada	
» Whitecap	» Cardinal Energy

Significant CO_2 Supply by Region

Gulf Coast Region – Source (User)

- » Jackson Dome, MS (Denbury)
- » Air Products (Denbury)
- » Nutrien (Denbury)
- » Petra Nova (Hilcorp)

Permian Basin Region – Source (Owner)

- » Bravo Dome, NM (Kinder Morgan, Occidental)
- » McElmo Dome, CO (ExxonMobil, Kinder Morgan)
- » Sheep Mountain, CO (ExxonMobil, Occidental)

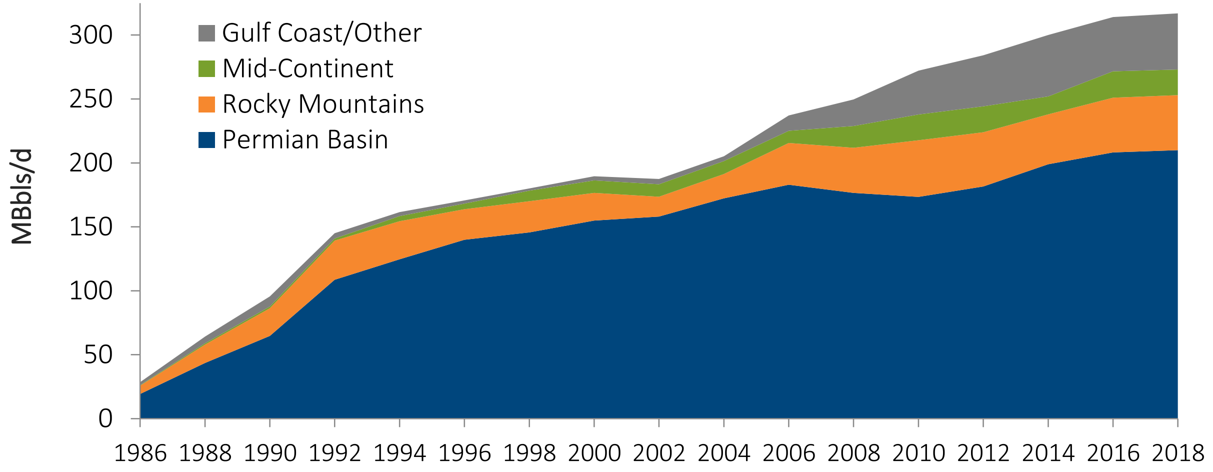
Rocky Mountain Region – Source (Owner)

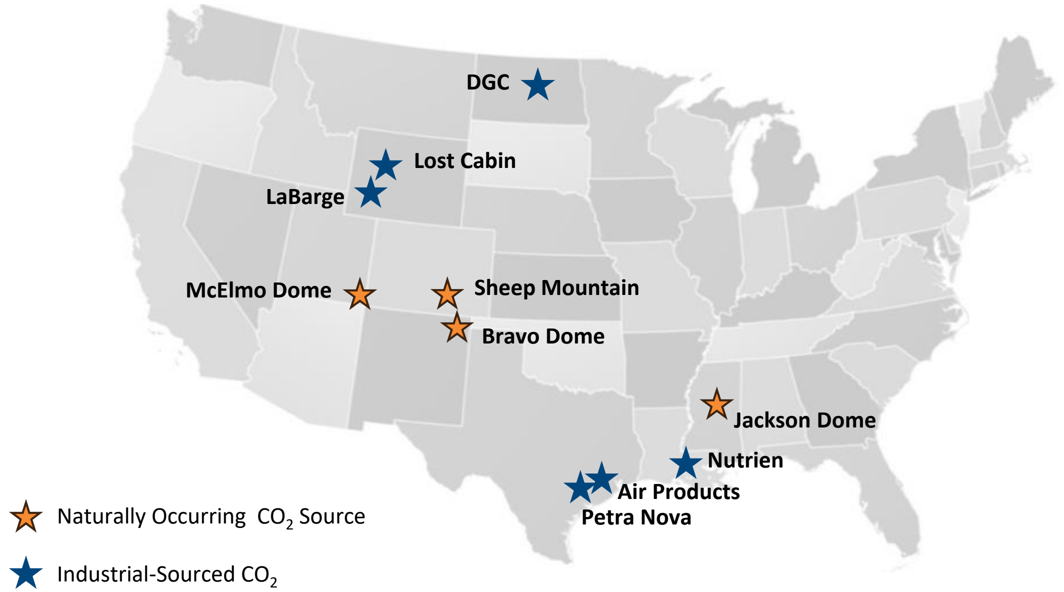
- » LaBarge, WY (ExxonMobil, Denbury)
- » Lost Cabin, WY (ConocoPhillips)

Canada – Source (User)

- » Dakota Gasification (Whitecap, Apache)

CO_2 EOR Oil Production by Region[1]





1) Source: Advanced Resources International for data through 2014; state EOR data 2015-2018.

Abundant CO_2 Supply & No Significant Capital Required for Several Years

Gulf Coast CO_2 Supply	Rocky Mountain CO_2 Supply

Jackson Dome

- Proved CO_2 reserves as of 12/31/20: ~4.6 Tcf[(1)]
- Additional probable CO_2 reserves as of 12/31/20: ~0.9 Tcf

Industrial-Sourced CO_2

Current Sources

- Air Products (hydrogen plant): ~45 MMcf/d
- Nutrien (ammonia products): ~20 MMcf/d

LaBarge Area

- Estimated field size: 750 square miles
- Estimated recoverable CO_2: 100 Tcf

Shute Creek – ExxonMobil Operated

- Proved reserves as of 12/31/20: ~1.1 Tcf
- Denbury has a 1/3 overriding royalty interest and could receive up to ~115 MMcf/d of CO_2 by 2021 at current plant capacity

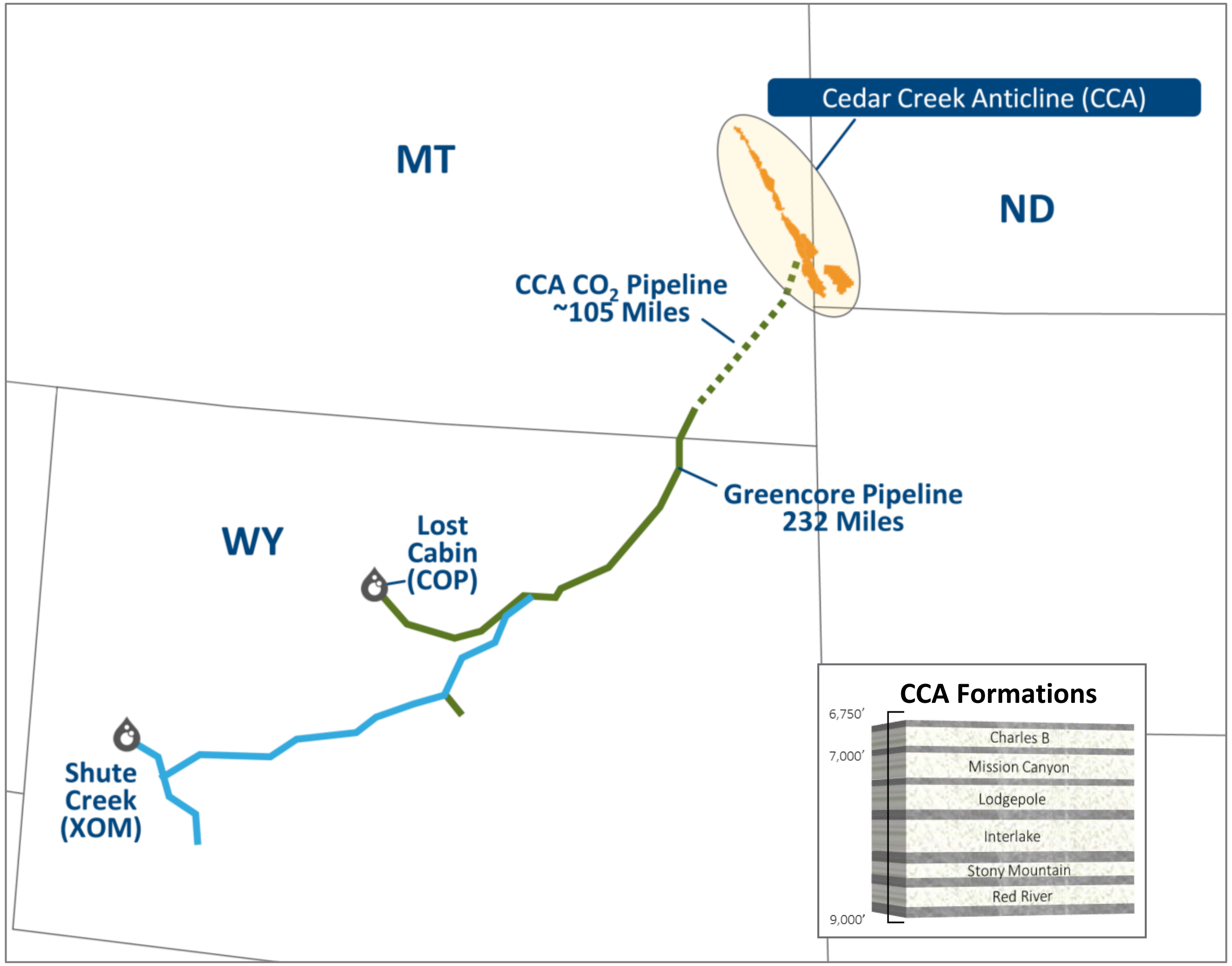
Lost Cabin – ConocoPhillips Operated

- Potential to receive up to 30 MMcf/d of CO_2

1) Reported on a gross (8/8th's) basis.

CCA CO_2 EOR Development

EOR Formation Details	
Initial Formations Targeted	Red River, Interlake, Stony Mountain
Field Discovery Timeframe (Oil)	1930's (Discovery), 1950's (Development)
Formation Type	Dolomite
Depth	7,000 – 9,000 ft
Original Reservoir Pressure	3,600 – 4,140 psi
CO_2 Flood Type	Miscible
API Gravity	29-38
Average Perm	5 md
Average Porosity	11.4%
OOIP	~5 Billion Barrels
Oil Recovered to Date	~700 Million Barrels
Est. Tertiary Recovery Factor	8 – 15%



Oyster Bayou A2 Development Expansion

Development Overview

New A2 Development Expansion

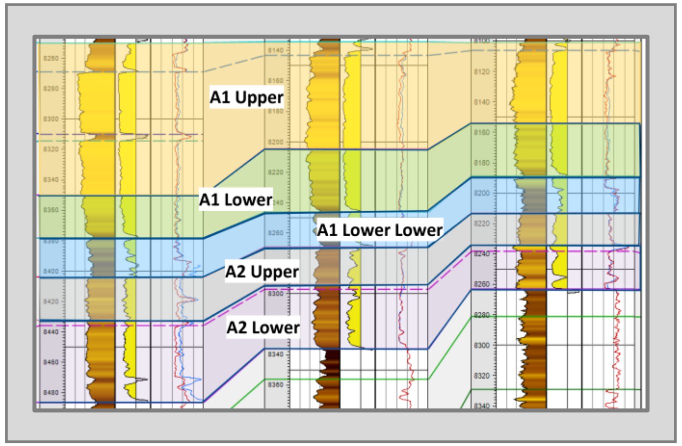
- Expanding A2 reservoir development in adjacent down-dip area
- Field compression capacity increased by 30 MMcf/d
- Total capital spend $10 million
- ~1.2 MMBbl proved reserves

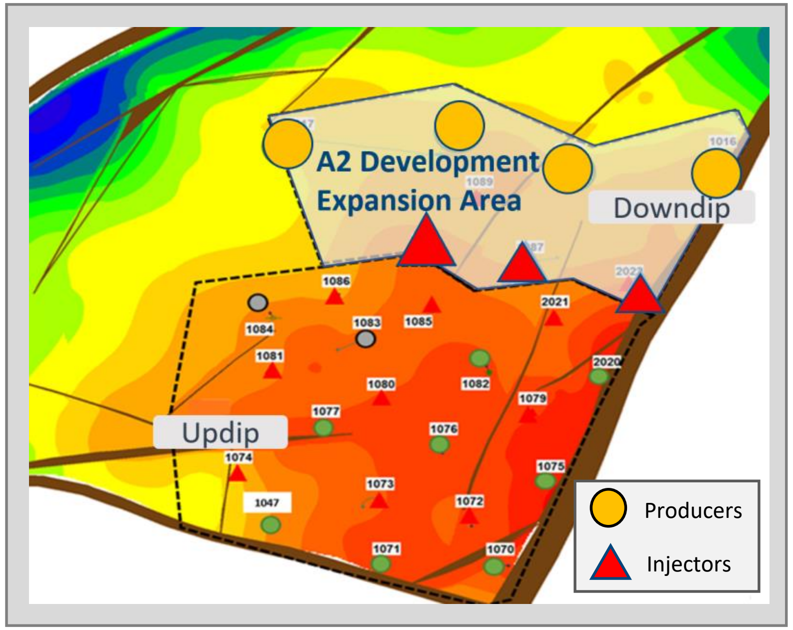
Project milestones

- Construction started in January 2020 and completed in early 2Q20
- Commenced CO_2 injection in April 2020 and first production in 2Q20
- 2 out of 4 producers responding at ~350 net BOE/d at the end of January, in line with expectations
- Additional development opportunities in A1 and A2 reservoirs

Producing zone in other phases

Development Expansion targeting A2 reservoir





Houston Acreage Land Sale Update

Transaction Highlights

- $49 million closed as of December 2020
  - $20 million closed in 2018-2019
  - $14 million closed in July 2020
  - $11 million closed in October 2020
  - $4 million closed in December 2020
- $30 - $50 million estimated value in remaining acreage

Conroe

Commercial and residential development surface acreage
Sold ~2,500 acres
Remaining ~150 acres

Webster

Commercial development surface acreage
Sold ~30 acres
Remaining ~400 acres

Multiple parcels along I-45 frontage road

2020 Proved Reserves

	Oil (MMBbl)	Gas (Bcf)	Total (MMBOE)	PV-10 Value[2] (Billion)	SEC Oil Pricing[1]
Proved reserves[1] at December 31, 2019	226	24	230	$2.6	$55.69
2020 production	(18)	(3)	(19)	(0.2)	
Revisions due to price changes	(54)	(9)	(55)	(1.8)	
Other revisions	(10)	4	(9)	(0.1)	
Sales of minerals in place	(4)	0	(4)	0	
Accretion of discount	–	–	–	0.2	
Proved reserves[1] at December 31, 2020	140	16	143	$0.7	$39.57

PDP	126	88%
PDNP	13	9%
PUD	4	3%
Total MMBOE	143	100%

1) Estimated proved reserves and PV-10 Value for year-end 2020 were computed using first-day-of-the-month 12-month average prices of $39.57 per Bbl for oil (based on NYMEX prices) and $1.99 per million British thermal unit ("MMBtu") for natural gas (based on Henry Hub cash prices), adjusted for prices received at the field. Comparative prices for year-end 2019 were $55.69 per Bbl of oil and $2.58 per MMBtu for natural gas, adjusted for prices received at the field.

2) PV-10 Value is an estimated discounted net present value of Denbury's proved reserves at December 31, 2019 and 2020, before projected income taxes, using a 10% per annum discount rate (a non-GAAP measure). See press release attached as exhibit 99.1 to the Form 8-K filed February 25, 2021, as well as slide 41 for additional information indicating why the Company believes this non-GAAP measure is useful to investors.

Denbury Reacquires NEJD and Free State Pipelines

Reduced debt and lowered cash interest while maximizing flexibility for future CCUS operations

Transaction Highlights

Summary

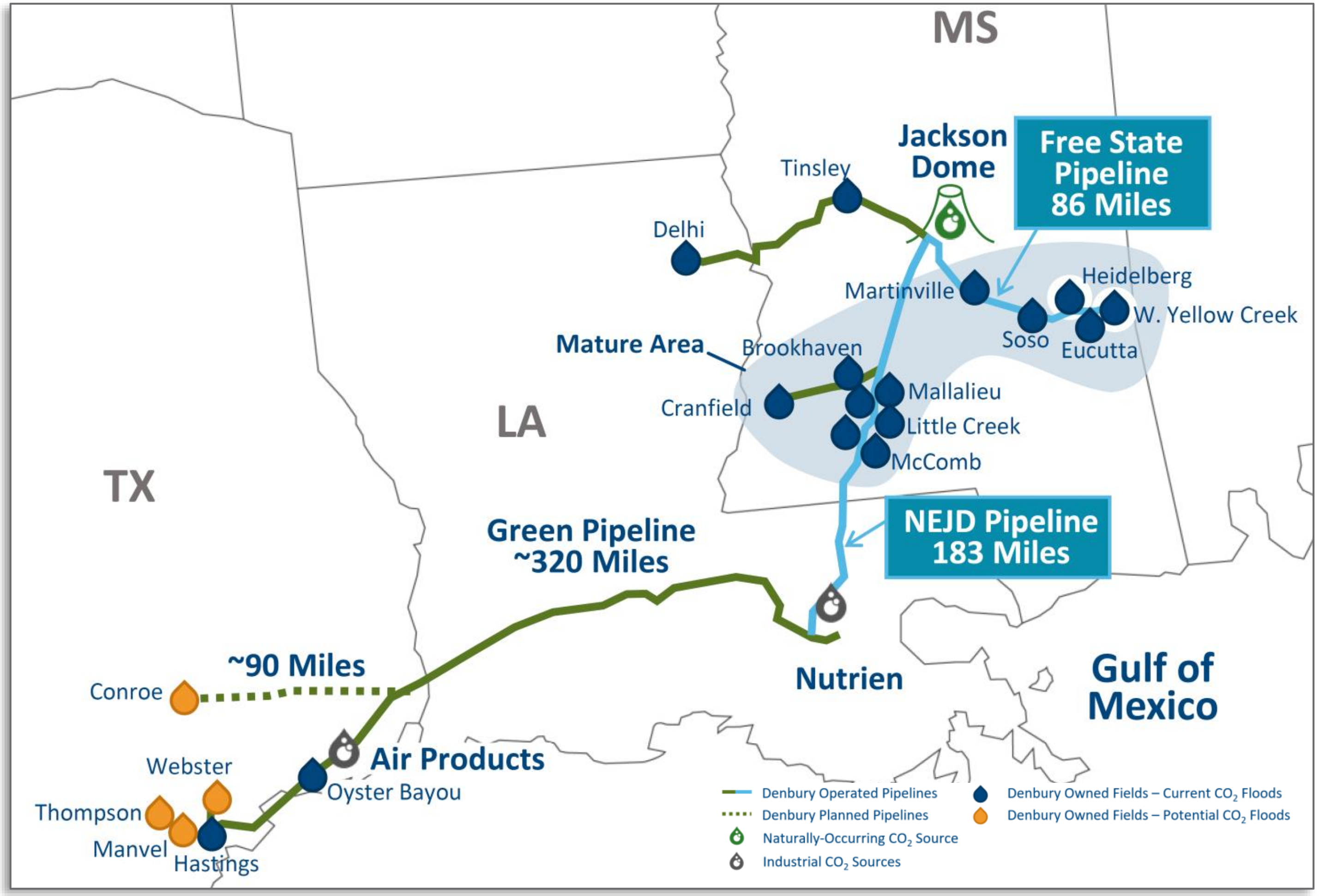
- Reacquired the NEJD Pipeline for $70 million and the Free State Pipeline for $22.5 million

Details

- Remaining $70 million in NEJD financing lease payments to be paid in four equal payments on January 31, April 30, July 31 and October 31, 2021
- Reacquired Free State Pipeline with a single payment of $22.5 million on October 30, 2020

Benefits

- Reduces total debt by $25 million
- Lowers annual cash interest expense
- All Gulf Coast CO_2 pipelines now 100% owned and operated, ensuring maximum flexibility for future CCUS operations



Production by Area

Average Daily Production by Area (BOE/d)

Field	2018	2019	1Q20	2Q20	3Q20	4Q20	2020
Delhi	4,368	4,324	3,813	3,529	3,208	3,132	3,419
Hastings	5,596	5,403	5,232	4,722	4,473	4,598	4,755
Heidelberg	4,355	4,195	4,371	4,366	4,256	4,198	4,297
Oyster Bayou	4,843	4,345	3,999	3,871	3,526	3,880	3,818
Tinsley	5,530	4,608	4,355	3,788	4,042	3,654	3,959
Bell Creek	4,113	5,228	5,731	5,715	5,551	5,079	5,518
Salt Creek	2,109	2,143	2,149	1,386	2,167	2,007	1,928
West Yellow Creek	205	640	775	695	588	614	668
Mature area(1) and other	6,709	6,475	6,436	5,256	5,683	5,718	5,773
Total tertiary production	37,828	37,361	36,861	33,328	33,494	32,880	34,135
Gulf Coast non-tertiary	4,391	4,201	4,173	3,805	3,728	3,523	3,807
Cedar Creek Anticline	14,837	14,090	13,046	11,988	11,485	11,433	11,985
Other Rockies non-tertiary	1,431	1,262	1,105	1,069	979	969	1,030
Total non-tertiary production	20,659	19,553	18,324	16,862	16,192	15,925	16,822
Total continuing production	58,487	56,914	55,185	50,190	49,686	48,805	50,957
Property divestitures(2)	1,854	1,299	780	–	–	–	194
Total production	60,341	58,213	55,965	50,190	49,686	48,805	51,151

1) Mature area includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, and Soso fields.
2) Includes production from Lockhart Crossing Field sold in the third quarter of 2018, Citronelle Field sold in July 2019 and non-tertiary production related to the March 2020 sale of half of our nearly 100% working interests in Webster, Thompson, Manvel, and East Hastings fields.

Analysis of Total Operating Costs

Ability to flex operating costs in a low oil price environment

LOE Cost Type ($/BOE)	Correlation with Oil Price	**2018**	**2019**	1Q20	2Q20	3Q20	4Q20	**2020**
CO_2 Costs	High	$3.07	$3.05	$2.98	$2.65	$2.28	$2.80	$2.69
Power & Fuel	Moderate	6.32	6.34	6.38	5.99	6.05	6.61	6.26
Labor & Overhead	Low	6.61	7.11	6.52	6.34	6.41	6.30	6.39
Repairs & Maintenance	Moderate	0.91	0.99	0.77	0.60	0.74	0.71	0.71
Chemicals	Moderate	1.06	1.04	1.06	0.81	0.79	0.89	0.89
Workovers	High	2.96	2.57	2.31	0.57	1.45	1.77	1.55
Other	Low	1.31	1.36	1.44	0.84	1.22	0.91	1.11
Total Normalized LOE[1]		$22.24	$22.46	$21.46	$17.80	$18.94	$19.99	$19.60
Special or Unusual Items[2]		—	—	—	—	(3.37)	—	(0.82)
Total LOE		$22.24	$22.46	$21.46	$17.80	$15.57	$19.99	$18.78
Oil Price								
NYMEX Oil Price		*$64.81*	*$57.03*	*$46.35*	*$28.42*	*$40.87*	*$42.66*	*$39.59*
Realized Oil Price[3]		*$66.11*	*$58.26*	*$45.96*	*$24.39*	*$39.23*	*$40.63*	*$37.78*

1) Normalized LOE excludes special or unusual items (see footnote 2 below).
2) Special or unusual items consist of an insurance settlement reimbursement in the amount of $15 million related to the 2013 well incident in the Delhi field.
3) Excludes derivative settlements.

NYMEX Oil Differential Summary

NYMEX Oil Differentials

$ per barrel	**2018**	**2019**	1Q20	2Q20	3Q20	4Q20	**2020**
Tertiary oil fields							
Gulf Coast region	*$2.73*	*$3.07*	*$0.84*	*($3.69)*	*($1.48)*	*($1.91)*	*($0.87)*
Rocky Mountain region	*(1.81)*	*(2.18)*	*(3.28)*	*(2.83)*	*(1.92)*	*(2.14)*	*(2.34)*
Gulf Coast Non-Tertiary	4.28	4.77	3.52	(2.81)	(0.50)	(1.25)	0.51
Cedar Creek Anticline	(1.30)	(1.78)	(2.34)	(5.71)	(1.95)	(2.27)	(2.96)
Other Rockies Non-Tertiary	(2.87)	(4.35)	(5.11)	(6.27)	(4.62)	(4.78)	(5.23)
Denbury totals	$1.30	$1.23	($0.38)	($4.03)	($1.64)	($2.03)	($1.81)

Senior Secured Bank Credit Facility Info

Commitments & borrowing base	▪ Borrowing Base / Commitment level: $575 million
Scheduled redeterminations	▪ Semiannually – May 1st and November 1st, next redetermination is May 2021
Maturity date	▪ January 30, 2024
Permitted additional debt	▪ Up to $150 million unsecured, in the aggregate, with automatic borrowing base reduction by 25% of amount borrowed ▪ Junior lien debt only permitted with consent of majority lenders
Dividends and stock repurchases	▪ No dividends or stock repurchases prior to September 18, 2021. Commencing September 18, 2021, such transactions are permitted if the Company has accumulated Free Cash Flow (as defined in credit facility) as long as (1) leverage is less than 2x, (2) availability under the credit facility is at least 20%, and (3) no event of default or borrowing base deficiency exists.
Asset sales	▪ Oil and gas property sales and/or hedge terminations >5% of borrowing base would likely result in borrowing base reduction
Anti-hoarding provisions	▪ If unrestricted cash in accounts > $75 million at the end of any week, must prepay excess borrowings next business day
Pricing grid	see table below
Covenants	▪ Total Debt / EBITDAX (as defined): < 3.50x at the end of each quarter ▪ Current Ratio: > 1.00x at the end of each quarter ▪ Hedges may not exceed 85% of estimated proved production on a monthly basis

Pricing grid:

Level	Borrowing Base Utilization	Libor margin[1] (bps)	ABR margin (bps)	Undrawn pricing (bps)
I	≤ 25.0%	300.0	200.0	50.0
II	≤ 50.0%	325.0	225.0	50.0
III	≤ 75.0%	350.0	250.0	50.0
IV	≤ 90.0%	375.0	275.0	50.0
V	> 90.0%	400.0	300.0	50.0

1) Minimum LIBOR rate 1%

Non-GAAP Measures

Reconciliation of net income (loss) (GAAP measure) to adjusted cash flows from operations (non-GAAP measure) to cash flows from operations (GAAP measure)

	2019					2020				
	Predecessor					Predecessor		Combined (non-GAAP)[1]	Successor	Combined (non-GAAP)[1]
In millions	Q1	Q2	Q3	Q4	FY	Q1	Q2	Q3	Q4	FY
Net income (loss) (GAAP measure)	($26)	$147	$73	$23	$217	$74	($697)	($806)	($53)	($1,483)
Adjustments to reconcile to adjusted cash flows from operations										
Depletion, depreciation, and amortization	57	58	55	63	234	97	55	42	41	234
Deferred income taxes	(9)	62	38	10	101	(4)	(102)	(302)	(3)	(411)
Stock-based compensation	3	4	3	3	12	2	1	0	8	12
Noncash fair value losses (gains) on commodity derivatives	92	(26)	(35)	64	94	(122)	86	18	80	62
Gain on debt extinguishment	—	(100)	(6)	(50)	(156)	(19)	—	—	—	(19)
Write-down of oil and natural gas properties	—	—	—	—	—	73	662	262	1	998
Reorganization items	—	—	—	—	—	—	—	811	—	811
Other	2	0	(2)	2	3	4	4	4	(2)	11
Adjusted cash flows from operations (non-GAAP measure)	$119	$145	$126	$115	$505	$105	$9	$29	$72	$215
Net change in assets and liabilities relating to operations	(55)	4	5	35	(11)	(43)	2	45	(65)	(61)
Cash flows from operations (GAAP measure)	$64	$149	$131	$150	$494	$62	$11	$74	$7	$154

1) Combined results for the three months ended September 30, 2020 and year ended December 31, 2020 are provided for illustrative purposes and are derived from the financial statement line items from the successor and predecessor periods. A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed February 25, 2021 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.

Adjusted cash flows from operations is a non-GAAP measure that represents cash flows provided by operations before changes in assets and liabilities, as summarized from the Company's Consolidated Statements of Cash Flows. Adjusted cash flows from operations measures the cash flows earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. Management believes that it is important to consider this additional measure, along with cash flows from operations, as it believes the non-GAAP measure can often be a better way to discuss changes in operating trends in its business caused by changes in production, prices, operating costs and related factors, without regard to whether the earned or incurred item was collected or paid during that period.

Non-GAAP Measures

Reconciliation of net income (loss) (GAAP measure) to adjusted EBITDAX (non-GAAP measure)

	2019					2020				
	Predecessor					Predecessor		Combined (non-GAAP)[1]	Successor	Combined (non-GAAP)[1]
In millions	Q1	Q2	Q3	Q4	FY	Q1	Q2	Q3	Q4	FY
Net income (loss) (GAAP measure)	($26)	$147	$73	$23	$217	$74	($697)	($806)	($53)	($1,483)
Adjustments to reconcile to Adjusted EBITDAX										
Interest expense	17	20	23	21	82	20	21	8	1	50
Income tax expense (benefit)	(11)	65	37	13	104	(11)	(102)	(304)	(3)	(419)
Depletion, depreciation, and amortization	57	58	55	63	234	97	55	42	41	234
Noncash fair value losses (gains) on commodity derivatives	92	(26)	(35)	64	94	(122)	86	18	80	62
Stock-based compensation	3	4	3	3	12	2	1	1	8	12
Gain on debt extinguishment	—	(100)	(6)	(50)	(156)	(19)	—	—	—	(19)
Write-down of oil and natural gas properties	—	—	—	—	—	73	662	262	1	998
Reorganization items, net	—	—	—	—	—	—	—	850	—	850
Severance-related expense	—	—	—	19	19	—	2	1	—	3
Noncash, non-recurring and other	6	1	(5)	(1)	1	2	11	21	2	38
Adjusted EBITDAX (non-GAAP measure)	$138	$169	$145	$155	$607	$116	$39	$93	$77	$326

1) Combined results for the three months ended September 30, 2020 and year ended December 31, 2020 are provided for illustrative purposes and are derived from the financial statement line items from the successor and predecessor periods. A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed February 25, 2021 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.

Adjusted EBITDAX is a non-GAAP financial measure which management uses and is calculated based upon (but not identical to) a financial covenant related to “Consolidated EBITDAX” in the Company’s senior secured bank credit facility, which excludes certain items that are included in net income, the most directly comparable GAAP financial measure. Items excluded include interest, income taxes, depletion, depreciation, and amortization, and items that the Company believes affect the comparability of operating results such as items whose timing and/or amount cannot be reasonably estimated or are non-recurring. Management believes Adjusted EBITDAX may be helpful to investors in order to assess the Company’s operating performance as compared to that of other companies in its industry, without regard to financing methods, capital structure or historical costs basis. It is also commonly used by third parties to assess leverage and the Company’s ability to incur and service debt and fund capital expenditures. Adjusted EBITDAX should not be considered in isolation, as a substitute for, or more meaningful than, net income, cash flow from operations, or any other measure reported in accordance with GAAP. Adjusted EBITDAX may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDAX, EBITDAX or EBITDA in the same manner.

Non-GAAP Measures

Reconciliation of the standardized measure of discounted estimated future net cash flows after income taxes (GAAP measure) to PV-10 Value (non-GAAP measure)

	December 31,	
In millions	2019	2020
Standardized Measure (GAAP Measure)	$2,261	$655
Discounted estimated future income tax	355	48
PV-10 Value (Non-GAAP Measure)	$2,616	$703

PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. Denbury's 2019 and 2020 year-end estimated proved oil and natural gas reserves and proved CO_2 reserves quantities were prepared by the independent reservoir engineering firm of DeGolyer and MacNaughton. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. Management believes PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property-by-property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by management and others in the industry to evaluate properties that are bought and sold, to assess the potential return on investment in the Company's oil and natural gas properties, and to perform impairment testing of oil and natural gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. PV-10 Value and the preliminary Standardized Measure do not purport to represent the fair value of the Company's oil and natural gas reserves.