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, the level and sustainability of the recent increases in worldwide oil prices from their COVID-19 coronavirus caused downturn, financial forecasts, oil price volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, statements or predictions related to the ultimate nature, timing and economic aspects of proposed carbon capture, use and storage industry arrangements, 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, the impact of current supply chain and inflationary pressures or expectations on our operational or other costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, borrowing capacity, price and availability of advantageous commodity derivative contracts or their predicted downside cash flow protection or cash settlement payments required, mark-to-market commodity derivative values, forecasted, 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 CO2 injections in particular fields or areas, including Cedar Creek Anticline ("CCA"), or initial production responses in tertiary flooding projects, other development activities, finding costs, interpretation or prediction of formation details, hydrocarbon reserve quantities and values, CO2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, the impact of changes or proposed changes in Federal or state laws or outcomes of any pending litigation, prospective legislation, orders or regulations affecting the oil and gas industry or environmental regulations, competition, rates of return, and overall worldwide or U.S. 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 produced; decisions as to production levels and/or pricing by OPEC+ or production levels by U.S. producers in future periods; success of our risk management techniques; 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 cybersecurity breaches, or from well incidents, climate events such as hurricanes, tropical storms, floods, forest fires, or other natural occurrences; 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 consequent 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, including without limitation, the Company’s most recent Form 10-K.

Statement Regarding CO2 Storage Associated with EOR: Our CO2 EOR operations provide an environmentally responsible method of utilizing CO2 for the primary purpose of oil recovery that also results in the associated underground storage of CO2. Any reference in this presentation to storage of CO2 associated with our EOR operations is not meant to encompass CO2 stored for the primary purpose of carbon sequestration.

Statement Regarding Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures. Any non-GAAP measure included herein is accompanied by a reconciliation to the most directly comparable U.S. GAAP measure along with a statement (or location of such statement which are exhibits to Company SEC periodic reports) on why the Company believes the measure is beneficial to investors, which statements are included at the end of this presentation.
Powering the Energy Transition With World-Leading Carbon Solutions

**Strategic Focus**

Leading in Carbon Capture, Use and Storage, including Enhanced Oil Recovery

**20+ years Experience Managing CO₂**

Safely transporting, injecting and monitoring large-scale volumes of CO₂

**1000+ miles of CO₂ Pipelines**

Owned and operated, strategically located in the Gulf Coast and Rocky Mountain areas

**Scope 3 Carbon Negative By 2030**

Through increasing our use of captured industrial-sourced CO₂

**Financial Strength and Flexibility**

Maintain strong financial position, disciplined capital allocation

---

NYSE: DEN

Market Cap: $4.5B
Enterprise Value: $4.5B

3Q21 Sales Volumes: 49,682 BOE/d

YE20 Proved O&G Reserves: 143 MMBOE

YE20 Proved CO₂ Reserves: 5.7 Tcf
Leading Sustainability

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

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

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

Net Negative Combined Scope 1 and Scope 2 CO₂ Emissions
Average of 2018, 2019 and 2020

- 1.2 million metric tons

Combined Scope 1 & 2 Emissions
1.8 million metric tons

Captured Industrial-Source CO₂
3.0 million metric tons

We utilized 3.0 million metric tons of industrially sourced CO₂ that could otherwise have been released into the atmosphere

Annual greenhouse gas emissions from over 650,000 cars

- 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 ~$300,000 employee charitable donations over last 7 years

- 7 out of 8 directors are independent, including independent Chairman of the Board
- 5 out of 8 directors added in connection with or after restructuring
- Code of Conduct and Ethics Rated “A” by NYSE Governance Services (Top 1%)
- Recently formed a Sustainability Committee of the Board of Directors

Consistent sustainability reporting (2014-2021) in accordance with GRI Standards.
Our most recent Corporate Responsibility Report can be accessed on our website at: csr.denbury.com

Car Emissions:
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020

Total Recordable Incident Rate (TRIR)

Consistent sustainability reporting (2014-2021) in accordance with GRI Standards.
Our most recent Corporate Responsibility Report can be accessed on our website at: csr.denbury.com

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Car Emissions:
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020

Total Recordable Incident Rate (TRIR)
Report Highlights – 2019/2020

- Delivered negative Scope 1 and Scope 2 carbon emissions for each year
- Reduced total Scope 1, Scope 2, and Scope 3 emissions by 12% since 2018
- Annually transported and injected an average of approximately 3 million metric tons of industrial-sourced CO₂
- Reduced our employee and contractor combined total recordable incident rate by 28% to a Company record low level
- Board of Directors with 25% female representation and a Sustainability Committee focused on providing oversight on important health and safety, climate change, environmental, social and community strategies and risks
Carbon Capture, Use and Storage (CCUS) Overview

CCUS – both through CO₂ EOR or direct CO₂ injection – is a proven technology with the potential for safe, long-term, deep underground containment of billions of tons of industrial-sourced CO₂.

**CO₂ Stored in Association with EOR**

1. Natural or Industrial CO₂
2. CO₂ pipeline
3. Inject CO₂ into Oilfield
4. CO₂ Recycled & Stored
5. Oil Sales
6. Production Well

**CO₂ Directly Stored**

1. Industrial CO₂
2. CO₂ pipeline
3. Inject CO₂ into Secure Geologic Formations
4. CO₂ Stored

**A proven process**

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

Experience gained from decades of safe CO₂ EOR operations translates directly into safe CCUS operations.

**Reduces atmospheric CO₂**

*CCUS has the potential to drive a significant reduction in atmospheric CO₂ emissions*

The NPC’s 2019 CCUS Report identified a reasonable path where the volume of CO₂ 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 CO₂ used in EOR operations and $50/ton for CO₂ 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.
The IEA’s Net-Zero Emissions by 2050 Scenario (NZE) outlines a carbon reduction pathway that is compliant with the Paris Agreement.

Multiple countries and companies have set targets aligned with emission reduction goals.

Current U.S. administration set a target to reduce emissions ~50% by 2030 (below 2005 levels).

Rapidly evolving economic and policy incentives to vastly increase CO₂ capture.
Proposed 45Q Revisions Significantly Increase CCUS Opportunity

**Congressional Proposals(1) for 45Q Enhancements**

<table>
<thead>
<tr>
<th></th>
<th>Current</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOR</td>
<td>$35/MT</td>
<td>$60/MT(3)</td>
</tr>
<tr>
<td>Dedicated Storage</td>
<td>$50/MT</td>
<td>$85/MT(3)</td>
</tr>
</tbody>
</table>

**Extends Construction Window**
Extend the date by which an industrial or DAC facility must be “under construction” from 1/1/2026 to 1/1/2032.

**Direct Pay Option**
Allows taxpayers to be treated as having made a payment of tax equal to the value of the 45Q credit.

**CCUS Capture Potential on the Cost Curve(2)**
2018 Emissions/Existing Facilities

*Capture Potential up to 1.2 Billion MTPA with $150/MT 45Q Incentive*

**Note:** MT – metric ton; MMT – million metric tons; MTPA – metric tons per annum; MMTPA – million metric tons per annum

2) National Petroleum Council (NPC) 2019 Report, Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage.
3) Includes prevailing wage requirements.
# Denbury Carbon Solutions Strategy

## Secure CO₂ Transportation & Storage Agreements
- Executed multiple agreements for CO₂ transportation and storage from greenfield projects – ammonia/biofuels
- Ongoing negotiations on potential transportation/storage > 50 million metric tons of CO₂ per year

## Develop Portfolio of CO₂ Storage Sites
- Agreed to jointly develop sequestration site in Texas with up to 400 million metric tons of CO₂ storage potential
- Ongoing negotiations on > 1 billion metric tons of CO₂ storage potential

## Replace Naturally-Sourced CO₂ in EOR Operations
- Current agreements allow for usage of industrial-captured CO₂ in EOR operations

## Prepare for 2-3X Infrastructure Expansion
- Developing market driven pipeline expansion

## Pursue Strategic Partnerships
- Evaluating participation in several opportunities
Industry-Leading Gulf Coast CCUS Infrastructure

Spanning the highly concentrated CO₂ emissions corridor of the industrial Gulf Coast

CO₂ Emissions
~2.6 billion tons/year from stationary sources in the U.S.

~230 million tons/year (~10% of total U.S.) within 30 miles of DEN Gulf Coast Infrastructure

Transportation, Use & Storage
- Strategically located, high-capacity network with ability to expand for maximum capacity and flexibility
- Immediate ability to contract takeaway of captured CO₂ for use in EOR operations
- Building a portfolio of permanent storage locations within close proximity to infrastructure

Source: National Petroleum Council (NPC) 2019 Report, Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage and 2019 EPA Greenhouse Gas Reporting Program data.
Denbury’s Extensive CO₂ Experience is Ideally Suited for CCUS

Over 20+ years, we have transported and injected a combined ~185 million metric tons of natural and industrial CO₂

Geologic Site Characterization
- Detailed analysis and modeling to ensure suitability of target reservoirs for long-term containment of injected CO₂

Secure Wellbore Design & Advanced Monitoring
- Wellbores constructed to isolate targeted formations and protect freshwater with emphasis on corrosion prevention, detection, and mitigation
- Routine well surveillance 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 CO₂ containment

Subsurface Surveillance
- 4D seismic imaging to aid in observation of CO₂ placement and conformance
- Sophisticated well logging
- Extensive use of fluid sampling and tracers
- Reservoir simulation modeling

CO₂ Handling & Processing Expertise
- Processing over 3.5 billion cubic feet (180,000 metric tons) of CO₂ per day
- Proven expertise in designing, building, and operating CO₂ pipelines, processing facilities, and gathering/distribution systems
**The CO₂ EOR Process**

**CO₂ Enhanced Oil Recovery (EOR) can produce nearly as much oil from a reservoir as was produced in either primary or secondary recovery**

---

**CO₂ EOR Process Overview**

- **Source CO₂**
- **CO₂ Injection Well**
- **Recycled CO₂**
- **Oil Reservoir**
- **Oil Sales**
- **Production Well**
- **CO₂ Recycle Facility**

---

- **CO₂ is injected into the reservoir, moves through the reservoir, and combines with oil that it contacts.**
- **The CO₂/oil combination then continues moving through the reservoir and into nearby production wells.**
- **Once on the surface, the oil and CO₂ are separated, the oil is processed for sale and the produced CO₂ is recycled into the reservoir along with supplemental source CO₂.**
- **Nearly all of the source CO₂ volume associated with EOR operations ultimately remains in secure underground containment.**

---

**Example Recovery of Original Oil in Place**

- **Primary**
  - ~20%
- **Secondary (Waterfloods)**
  - ~18%
- **CO₂ EOR (Tertiary)**
  - ~17%
**A Leading Producer of Low-Carbon Oil**

~25% of Denbury’s production is **Scope 3 carbon negative** through the use of industrial-sourced CO₂.

### CO₂ Emissions per Barrel of Oil Produced

<table>
<thead>
<tr>
<th>Scope 1</th>
<th>Scope 2</th>
<th>Scope 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>70 lbs/Bbl</td>
<td>90 lbs/Bbl</td>
<td>1,000 lbs/Bbl</td>
</tr>
<tr>
<td>Direct Development &amp; Operations</td>
<td>Indirect Emissions, Utilities &amp; Electricity</td>
<td>Transportation, Refining and Combustion of Petroleum Products</td>
</tr>
</tbody>
</table>

**Industrial CO₂ Injected**

1,700 lbs/Bbl

**Net Negative Carbon Emissions**

-540 lbs CO₂ per Bbl

**Denbury**

For every barrel of oil we produce **using industrial-sourced CO₂**, we are injecting 1,700 lbs of CO₂ that would otherwise be released into the atmosphere.

Injecting annually ~6.6 billion lbs or 3 million metric tons of captured CO₂

**Scope 1+2+3**

1,100 lbs/Bbl

**Conventional Oil Producer**

1) Based on a 3-year average of the years ending December 31, 2018, 2019 and 2020.

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

YE20 Reserves Summary\(^{(1)}\) (MMBOE)

|                           | Proved + Tertiary Potential
|---------------------------|-------------------------------
|                           | Tertiary Reserves             |
|                           | Proved | Potential | 70       | 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

**Note:** See “Slide Notes” on slide 24 in the appendix to this presentation for footnote explanations.
Rocky Mountain Region

YE20 Reserves Summary (MMBOE)

<table>
<thead>
<tr>
<th></th>
<th>Proved + Tertiary Potential</th>
<th>Tertiary Reserves</th>
<th>Non-Tertiary Reserves</th>
<th>Total MMBOE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Proved</td>
<td>Potential</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>12</td>
<td>547</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>47</td>
<td></td>
<td></td>
<td>606</td>
</tr>
</tbody>
</table>

Proved + Tertiary Potential by Field

- Bell Creek: 30
- Cedar Creek Anticline Area: 400 – 500
- Gas Draw: 10
- Grieve: 4
- Hartzog Draw: 30 – 40
- Salt Creek: 25 – 35

Denbury Operated CO₂ Pipelines
- CO₂ Pipelines Owned by Others
- CO₂ Resources Owned or Contracted
- Denbury Owned Fields – Current CO₂ Floods
- Denbury Owned Fields – Potential CO₂ Floods
- Fields Owned by Others – CO₂ EOR Candidates

Note: See “Slide Notes” on slide 24 in the appendix to this presentation for footnote explanations.
3Q21 Operational Update

**Rocky Mountain Region**

- **CCA CO₂ EOR Development** – ahead of schedule and at or under budget
  - ~105-mile Greencore CO₂ Pipeline extension to CCA – est. to complete installation by end of November 2021
  - Infield distribution network, pump station and well conversions – in progress for first injection 1Q22

**Gulf Coast Region**

- **Oyster Bayou A1 and A2 Developments**
  - Combined response to date ~900 net BOE/d
  - Additional response expected by YE21 from 2 remaining producers
Cedar Creek Anticline – A World Class CO₂ EOR Project

> 400 MMBbl total recovery potential using 100% industrial-sourced CO₂

**CO₂ Pipeline to CCA from Bell Creek**
- Installation underway, completion expected before the end of November 2021; ~$100 MM anticipated 2021 capital spend
- Services all CCA EOR development phases; represents < $0.50/Bbl across total project

**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. CO₂ 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 CO₂

**Additional Development Details**

- Evaluating further enhancements to project based on potential availability of additional CO₂
- Anticipated $10-15/Bbl Phase 1 and 2 tertiary lifting cost expected to meaningfully reduce overall corporate LOE/BOE

**CO₂ Emissions – Scope 3 Negative**

-77 million tons

-85 million tons

-8 million tons

Net Negative Carbon Emissions

CCA EOR Development utilizes 100% industrial-sourced CO₂

**Estimated Production Profile**

- Phase 1 incremental peak production 7,500 – 12,500 net Bbls/d
- Phase 1 CO₂ injection 1Q22
- Phase 1 production response 2H23

**Estimated Capital Profile**

Projected CCA Waterflood (1)

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

**Future EOR Potential**

Phase 1

Phase 2

2021 2023 2025 2027 2029 2031 2033 2035 2037 2039 2041

**Additional Development Details**

- Evaluating further enhancements to project based on potential availability of additional CO₂
- Anticipated $10-15/Bbl Phase 1 and 2 tertiary lifting cost expected to meaningfully reduce overall corporate LOE/BOE

**CO₂ Emissions – Scope 3 Negative**

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- Phase 1 CO₂ injection 1Q22
- Phase 1 production response 2H23

**Estimated Capital Profile**

Projected CCA Waterflood (1)

1) CCA waterflood proved production profile at $50/Bbl NYMEX
CCA CO₂ EOR Development Update

> 400 MMBbl total recovery potential using 100% industrial-sourced CO₂

Phase 1 development work

- 105-mile extension of Greencore CO₂ Pipeline to CCA
  - Impressive safety record – no recordable incidents to date
  - Over 85% complete at the end of September
  - Expect to complete installation by end of November 2021
  - 16” pipeline capable of transporting ~7 MMTPA

- 56-mile infield distribution network – installed by end of year

- Pump station – estimated completion 1Q22

- 74 well conversions from water to CO₂ injection – estimated completion 1Q22

Ahead of schedule and at or under budget

- Phase 1 CO₂ injection 1Q22
- Phase 1 production response 2H23

Note: MMTPA – million metric tons per annum
Oyster Bayou CO₂ Development

Continuing to identify opportunities in active CO₂ floods through active monitoring programs

A1 and A2 Developments
- Projects completed in 2020 and 2021
- Total development cost ~$16MM
- Combined response to date ~900 net Bbl/d
- Additional future CO₂ infield development opportunities in Oyster Bayou A1 and A2

Oyster Bayou Production (Net Bbl/d)

2020 A2 Development

2021 A1 Development

Producing zone in other phases

2021 Development targeting A1 reservoir

2020 Development targeting A2 reservoir
2021 YTD Development Capital & Sales Volumes

Capital ($MM)

- **2021 Budget Capital** $250 – $270 MM\(^{(1)}\)
- **3Q21 YTD Capital** $174 Million
  - **CCA CO\(_2\) Pipeline** Long-Term Infrastructure Capital
    - $48
  - **Field Capital** Tertiary & Non-Tertiary
    - Tinsley Perry CO\(_2\) Pilot
    - Oyster Bayou A1 Development Expansion
    - CCA CO\(_2\) Facilities & Well work
    - Maintenance Activities
    - $103
  - **Other Capitalized Items\(^{(2)}\)**
    - $23

Sales Volumes (BOE/d)

- **3Q21 YTD Capital** $174 Million
  - 1Q21: 47,357
  - 2Q21: 49,133
  - 3Q21: 49,682

**4Q21 Guidance** ~50,000

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.
### Operating Margin

#### Pre-Hedge Cash Operating Margin/BOE\(^{(1)}\)

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Realized Price</th>
<th>Cash Operating Margin</th>
<th>Interest</th>
<th>G&amp;A(^{(2)})</th>
<th>Transportation, Marketing &amp; Taxes(^{(3)})</th>
<th>Lease Operating(^{(4)})</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1Q21</td>
<td>$55.24</td>
<td>$26.02</td>
<td>$0.36</td>
<td>$3.35</td>
<td>$6.28</td>
<td>$19.23</td>
<td>$35.05</td>
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<tr>
<td>2Q21</td>
<td></td>
<td>$28.51</td>
<td>$0.28</td>
<td>$2.88</td>
<td>$6.91</td>
<td>$24.65</td>
<td>$30.05</td>
</tr>
<tr>
<td>3Q21</td>
<td></td>
<td>$32.43</td>
<td>$0.15</td>
<td>$2.81</td>
<td>$6.59</td>
<td>$25.50</td>
<td>$32.43</td>
</tr>
</tbody>
</table>

**Cash Operating Margin**

\[\$32.43\] per BOE

**Cash Operating Costs**

\[\$35.05\] per BOE

---

#### Industry-Leading Oil Weighting\(^{(5)}\)

2Q21

<table>
<thead>
<tr>
<th>Peer</th>
<th>% Oil Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>DEN</td>
<td>97%</td>
</tr>
<tr>
<td>Peer A</td>
<td>51%</td>
</tr>
<tr>
<td>Peer B</td>
<td></td>
</tr>
<tr>
<td>Peer C</td>
<td></td>
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<tr>
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<td>Peer H</td>
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<td>Peer J</td>
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<td>Peer K</td>
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</tr>
</tbody>
</table>

Peer Average

\[51\%\] Oil

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1) Excludes impacts of hedging and selected items of other expense and CO2 operating margin.

2) G&A excludes non-cash compensation of approximately $18 million ($4.15/BOE), $3 million ($0.57/BOE) and $3 million ($0.56/BOE) for the three months ending March 31, 2021, June 30, 2021, and September 30, 2021, respectively.

3) Includes transportation, marketing and taxes other than income.

4) Lease operating expenses include utility credits of approximately $15 million ($3.51/BOE) and $1 million ($0.31/BOE) for the three months ending March 31, 2021 and June 30, 2021, respectively, and a utility credit adjustment of approximately $0.3 million ($0.06/BOE) for the three months ending September 30, 2021. See slide 32 for a detail of operating expenses.

5) Source: Peer filings for the second quarter ended 6/30/2021. Peers include CLR, CRC, DVN, LPI, MRO, MUR, OAS, PDCE, PXD, SM, and WLL.
Leverage ratio of 0.05x as of September 30, 2021

Total Debt
(In millions)

<table>
<thead>
<tr>
<th>Date</th>
<th>Total Debt</th>
<th>Sr. Secured Bank Credit Facility</th>
<th>Pipeline financings – repaid on October 29, 2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>9/30/2020</td>
<td>$176</td>
<td>$85</td>
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<tr>
<td>12/31/2020</td>
<td>$138</td>
<td>$68</td>
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<td>3/31/2021</td>
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<td>$70</td>
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<td>6/30/2021</td>
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<tr>
<td>9/30/2021</td>
<td>$17</td>
<td>$35</td>
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</tbody>
</table>

Credit Facility Overview
Sr. Secured Bank Credit Facility
- $575 million borrowing base
- $563 million availability at September 30, 2021
  - No outstanding borrowings
  - $12 million of letters of credit issued
- Reaffirmed November 2021; next semi-annual redetermination in May 2022
- 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
Slide Notes

Slide 14 – 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 15 – 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.
Appendix
Significant CO₂ 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]

<table>
<thead>
<tr>
<th>Region</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian</td>
<td>9-21</td>
</tr>
<tr>
<td>East &amp; Central Texas</td>
<td>6-15</td>
</tr>
<tr>
<td>Mid-Continent</td>
<td>6-13</td>
</tr>
<tr>
<td>California</td>
<td>3-7</td>
</tr>
<tr>
<td>South East Gulf Coast</td>
<td>3-7</td>
</tr>
<tr>
<td>Rockies</td>
<td>2-6</td>
</tr>
<tr>
<td>Other</td>
<td>0-5</td>
</tr>
<tr>
<td>Michigan/Illinois</td>
<td>2-4</td>
</tr>
<tr>
<td>Williston</td>
<td>1-3</td>
</tr>
<tr>
<td>Appalachia</td>
<td>1-2</td>
</tr>
</tbody>
</table>

2.8 to 6.6 Billion Barrels
Rocky Mountain Region[2]

Denbury’s fields represent ~10% of total potential[3]

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.
CO₂ EOR is a Proven Process

Significant CO₂ EOR Operators by Region

<table>
<thead>
<tr>
<th>Region</th>
<th>Operators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf Coast Region</td>
<td>Denbury, Hilcorp</td>
</tr>
<tr>
<td>Permian Basin Region</td>
<td>Occidental, Kinder Morgan</td>
</tr>
<tr>
<td>Rocky Mountain Region</td>
<td>Denbury, Chevron</td>
</tr>
<tr>
<td>Canada</td>
<td>Whitecap, Cardinal Energy</td>
</tr>
</tbody>
</table>

Significant CO₂ Supply by Region

<table>
<thead>
<tr>
<th>Region</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf Coast Region – Source</td>
<td>Jackson Dome, Air Products, Nutrien,</td>
</tr>
<tr>
<td></td>
<td>Petra Nova (Hilcorp)</td>
</tr>
<tr>
<td>Permian Basin Region – Source</td>
<td>Bravo Dome, McElmo Dome, Sheep Mountain,</td>
</tr>
<tr>
<td></td>
<td>Occidental, Kinder Morgan, ExxonMobil, Occidental</td>
</tr>
<tr>
<td>Rocky Mountain Region – Source</td>
<td>LaBarge, Lost Cabin, McElmo Dome,</td>
</tr>
<tr>
<td>Canada</td>
<td>Naturally Occurring CO₂ Source, Industrial-Sourced CO₂</td>
</tr>
</tbody>
</table>

CO₂ EOR Oil Production by Region

1) Source: Advanced Resources International for data through 2014; state EOR data 2015-2018.
# Current Natural and Industrial CO₂ Sources

## Gulf Coast CO₂ Supply

### Jackson Dome
- Proved CO₂ reserves as of 12/31/20: ~4.6 Tcf<sup>1)</sup>
- Additional probable CO₂ reserves as of 12/31/20: ~0.9 Tcf

## Rocky Mountain CO₂ Supply

### LaBarge Area
- Estimated field size: 750 square miles
- Estimated recoverable CO₂: 100 Tcf

### Shute Creek<sup>2)</sup> – 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 CO₂ by 2021 at current plant capacity

### Lost Cabin<sup>3)</sup>
- Potential to receive up to 30 MMcf/d of CO₂

---

1) Reported on a gross (8/8ths) basis.
2) On October 25, 2021, ExxonMobil announced that it has started the process for engineering, procurement, and construction contracts to expand carbon capture and storage at the LaBarge facility.
3) Effective July 1, 2021, Contango Oil & Gas acquired Lost Cabin from ConocoPhillips.
CCA CO₂ EOR Development

**EOR Formation Details**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Formations Targeted</td>
<td>Red River, Interlake, Stony Mountain</td>
</tr>
<tr>
<td>Field Discovery Timeframe (Oil)</td>
<td>1930’s (Discovery), 1950’s (Development)</td>
</tr>
<tr>
<td>Formation Type</td>
<td>Dolomite</td>
</tr>
<tr>
<td>Depth</td>
<td>7,000 – 9,000 ft</td>
</tr>
<tr>
<td>Original Reservoir Pressure</td>
<td>3,600 – 4,140 psi</td>
</tr>
<tr>
<td>CO₂ Flood Type</td>
<td>Miscible</td>
</tr>
<tr>
<td>API Gravity</td>
<td>29-38</td>
</tr>
<tr>
<td>Average Perm</td>
<td>5 md</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>11.4%</td>
</tr>
<tr>
<td>OOIP</td>
<td>~5 Billion Barrels</td>
</tr>
<tr>
<td>Oil Recovered to Date</td>
<td>~700 Million Barrels</td>
</tr>
<tr>
<td>Est. Tertiary Recovery Factor</td>
<td>8 – 15%</td>
</tr>
</tbody>
</table>
Supports Denbury’s CO₂ EOR focused strategy, utilizing 100% industrial-sourced CO₂

**Transaction Highlights**
- $10.9 million purchase price (after closing adjustments) includes 46-mile CO₂ pipeline closed March 3, 2021
- Potential net reserves 13.7 MMBOE
- Annually utilizes nearly 400,000 tons of industrial-sourced CO₂

**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
- Net 3Q21 average ~3,000 BOE/d
## Average Daily Sales Volumes by Area

### Average Daily Sales Volumes by Area (BOE/d)

<table>
<thead>
<tr>
<th>Field</th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
<th>4Q20</th>
<th>2020</th>
<th>1Q21</th>
<th>2Q21</th>
<th>3Q21</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delhi</td>
<td>4,368</td>
<td>4,324</td>
<td>3,813</td>
<td>3,529</td>
<td>3,208</td>
<td>3,132</td>
<td>3,419</td>
<td>2,925</td>
<td>2,931</td>
<td>2,859</td>
</tr>
<tr>
<td>Heidelberg</td>
<td>4,355</td>
<td>4,195</td>
<td>4,371</td>
<td>4,366</td>
<td>4,256</td>
<td>4,198</td>
<td>4,297</td>
<td>4,054</td>
<td>3,942</td>
<td>3,895</td>
</tr>
<tr>
<td>Tinsley</td>
<td>5,530</td>
<td>4,608</td>
<td>4,355</td>
<td>3,788</td>
<td>4,042</td>
<td>3,654</td>
<td>3,959</td>
<td>3,424</td>
<td>3,455</td>
<td>3,390</td>
</tr>
<tr>
<td>Bell Creek</td>
<td>4,113</td>
<td>5,228</td>
<td>5,731</td>
<td>5,715</td>
<td>5,551</td>
<td>5,079</td>
<td>5,518</td>
<td>4,614</td>
<td>4,394</td>
<td>4,330</td>
</tr>
<tr>
<td>Other Rockies(1)</td>
<td>2,116</td>
<td>2,196</td>
<td>2,199</td>
<td>1,393</td>
<td>2,167</td>
<td>2,007</td>
<td>1,942</td>
<td>2,573</td>
<td>4,378</td>
<td>4,703</td>
</tr>
<tr>
<td>Other Gulf Coast(2)</td>
<td>6,907</td>
<td>7,062</td>
<td>7,161</td>
<td>5,944</td>
<td>6,271</td>
<td>6,332</td>
<td>6,427</td>
<td>6,098</td>
<td>6,074</td>
<td>5,907</td>
</tr>
<tr>
<td>Total tertiary sales</td>
<td>37,828</td>
<td>37,361</td>
<td>36,861</td>
<td>33,328</td>
<td>32,880</td>
<td>32,468</td>
<td>33,452</td>
<td>33,369</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gulf Coast non-tertiary</td>
<td>4,391</td>
<td>4,201</td>
<td>4,173</td>
<td>3,805</td>
<td>3,728</td>
<td>3,523</td>
<td>3,807</td>
<td>3,621</td>
<td>3,415</td>
<td>3,763</td>
</tr>
<tr>
<td>Cedar Creek Anticline</td>
<td>14,837</td>
<td>14,090</td>
<td>13,046</td>
<td>11,988</td>
<td>11,485</td>
<td>11,433</td>
<td>11,985</td>
<td>11,150</td>
<td>10,918</td>
<td>11,182</td>
</tr>
<tr>
<td>Other Rockies non-tertiary(1)</td>
<td>1,431</td>
<td>1,262</td>
<td>1,105</td>
<td>1,069</td>
<td>979</td>
<td>969</td>
<td>1,030</td>
<td>1,118</td>
<td>1,348</td>
<td>1,368</td>
</tr>
<tr>
<td>Total non-tertiary sales</td>
<td>20,659</td>
<td>19,553</td>
<td>18,324</td>
<td>16,862</td>
<td>16,192</td>
<td>15,925</td>
<td>16,822</td>
<td>15,889</td>
<td>15,681</td>
<td>16,313</td>
</tr>
<tr>
<td>Total continuing sales</td>
<td>58,487</td>
<td>56,914</td>
<td>55,185</td>
<td>50,190</td>
<td>49,686</td>
<td>48,805</td>
<td>50,957</td>
<td>47,357</td>
<td>49,133</td>
<td>49,682</td>
</tr>
<tr>
<td>Property divestitures(3)</td>
<td>1,854</td>
<td>1,299</td>
<td>780</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>194</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Total sales</td>
<td>60,341</td>
<td>58,213</td>
<td>55,965</td>
<td>50,190</td>
<td>49,686</td>
<td>48,805</td>
<td>51,151</td>
<td>47,357</td>
<td>49,133</td>
<td>49,682</td>
</tr>
</tbody>
</table>

1. Includes Big Sand Draw and Beaver Creek fields acquired on March 3, 2021.
2. Includes our mature properties (Brookhaven, Cranfield, Escutta, Little Creek, Mallette, Martinville, McComb and Soso fields) and West Yellow Creek Field.
3. 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

<table>
<thead>
<tr>
<th>LOE Cost Type ($/BOE)</th>
<th>Correlation with Commodity Price</th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
<th>4Q20</th>
<th>2020</th>
<th>1Q21</th>
<th>2Q21</th>
<th>3Q21</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO₂ Costs</strong></td>
<td>High</td>
<td>$3.07</td>
<td>$3.05</td>
<td>$2.98</td>
<td>$2.65</td>
<td>$2.28</td>
<td>$2.80</td>
<td>$2.69</td>
<td>$3.14</td>
<td>$4.18</td>
<td>$3.99</td>
</tr>
<tr>
<td><strong>Power &amp; Fuel</strong></td>
<td>Moderate</td>
<td>6.32</td>
<td>6.34</td>
<td>6.38</td>
<td>5.99</td>
<td>6.05</td>
<td>6.61</td>
<td>6.26</td>
<td>3.87</td>
<td>7.22</td>
<td>7.52</td>
</tr>
<tr>
<td><strong>Labor &amp; Overhead</strong></td>
<td>Low</td>
<td>6.61</td>
<td>7.11</td>
<td>6.52</td>
<td>6.34</td>
<td>6.41</td>
<td>6.30</td>
<td>6.39</td>
<td>7.30</td>
<td>7.21</td>
<td>7.40</td>
</tr>
<tr>
<td><strong>Repairs &amp; Maintenance</strong></td>
<td>Moderate</td>
<td>0.91</td>
<td>0.99</td>
<td>0.77</td>
<td>0.60</td>
<td>0.74</td>
<td>0.71</td>
<td>0.71</td>
<td>0.77</td>
<td>1.12</td>
<td>1.18</td>
</tr>
<tr>
<td><strong>Chemicals</strong></td>
<td>Moderate</td>
<td>1.06</td>
<td>1.04</td>
<td>1.06</td>
<td>0.81</td>
<td>0.79</td>
<td>0.89</td>
<td>0.89</td>
<td>0.95</td>
<td>0.96</td>
<td>0.98</td>
</tr>
<tr>
<td><strong>Workovers</strong></td>
<td>High</td>
<td>2.96</td>
<td>2.57</td>
<td>2.31</td>
<td>0.57</td>
<td>1.45</td>
<td>1.77</td>
<td>1.55</td>
<td>2.00</td>
<td>2.76</td>
<td>2.82</td>
</tr>
<tr>
<td><strong>Other</strong></td>
<td>Low</td>
<td>1.31</td>
<td>1.36</td>
<td>1.44</td>
<td>0.84</td>
<td>(2.15)</td>
<td>0.91</td>
<td>0.29</td>
<td>1.20</td>
<td>1.20</td>
<td>1.61</td>
</tr>
<tr>
<td><strong>Total LOE</strong>(1)</td>
<td></td>
<td>$22.24</td>
<td>$22.46</td>
<td>$21.46</td>
<td>$17.80</td>
<td>$15.57</td>
<td>$19.99</td>
<td>$18.78</td>
<td>$19.23</td>
<td>$24.65</td>
<td>$25.50</td>
</tr>
</tbody>
</table>

### Oil Price

<table>
<thead>
<tr>
<th></th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
<th>4Q20</th>
<th>2020</th>
<th>1Q21</th>
<th>2Q21</th>
<th>3Q21</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NYMEX Oil Price</strong></td>
<td>$64.81</td>
<td>$57.03</td>
<td>$46.35</td>
<td>$28.42</td>
<td>$40.87</td>
<td>$42.66</td>
<td>$39.59</td>
<td>$57.82</td>
</tr>
<tr>
<td><strong>Realized Oil Price</strong>(2)</td>
<td>$66.11</td>
<td>$58.26</td>
<td>$45.96</td>
<td>$24.39</td>
<td>$39.23</td>
<td>$40.63</td>
<td>$37.78</td>
<td>$56.28</td>
</tr>
</tbody>
</table>

1) Includes a 3Q20 insurance settlement reimbursement of $15 million related to the 2013 well incident in the Delhi field and utility credits of approximately $15 million ($3.51/BOE) and $1 million ($0.31/BOE) and for the three months ended March 31, 2021 and June 30, 2021, respectively.
2) Excludes derivative settlements.
## NYMEX Oil Differential Summary

### NYMEX Oil Differentials

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
<th>4Q20</th>
<th>2020</th>
<th>1Q21</th>
<th>2Q21</th>
<th>3Q21</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf Coast region</td>
<td>$2.94</td>
<td>$3.30</td>
<td>$1.18</td>
<td>$(3.59)</td>
<td>$(1.38)</td>
<td>$(1.85)</td>
<td>$(1.14)</td>
<td>$(1.37)</td>
<td>$(1.13)</td>
<td>$(1.77)</td>
</tr>
<tr>
<td>Rocky Mountain region</td>
<td>(1.50)</td>
<td>(2.01)</td>
<td>(2.78)</td>
<td>(4.68)</td>
<td>(2.03)</td>
<td>(2.30)</td>
<td>(2.80)</td>
<td>(1.80)</td>
<td>(1.59)</td>
<td>(1.72)</td>
</tr>
<tr>
<td>Total Company NYMEX Oil Differential</td>
<td>$1.30</td>
<td>$1.23</td>
<td>$(0.38)</td>
<td>$(4.03)</td>
<td>$(1.64)</td>
<td>$(2.03)</td>
<td>$(1.81)</td>
<td>$(1.54)</td>
<td>$(1.32)</td>
<td>$(1.75)</td>
</tr>
</tbody>
</table>

### Average realized oil price per barrel

- **excl. derivative settlements**
  - 2018: $66.11
  - 2019: $58.26
  - 2Q20: $45.96
  - 3Q20: $24.39
  - 4Q20: $39.23
  - 2020: $40.63
  - 1Q21: $37.78
  - 2Q21: $56.28
  - 3Q21: $64.70
  - Avg: $68.88

- **incl. derivative settlements**
  - 2018: $57.91
  - 2019: $59.40
  - 2Q20: $50.92
  - 3Q20: $34.64
  - 4Q20: $43.23
  - 2020: $43.94
  - 1Q21: $43.40
  - 2Q21: $47.00
  - 3Q21: $50.10
  - Avg: $51.35
Hedge Portfolio – As of November 3, 2021

<table>
<thead>
<tr>
<th>NYMEX Oil Hedges</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4Q</td>
<td>1H</td>
</tr>
<tr>
<td><strong>Fixed-Price Swaps</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volumes Hedged (Bbls/d)</strong></td>
<td>29,000</td>
<td>15,500</td>
</tr>
<tr>
<td>Swap Price(^{(1)})</td>
<td>$43.86</td>
<td>$49.01</td>
</tr>
<tr>
<td><strong>Collars</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Volumes Hedged (Bbls/d)</strong></td>
<td>4,000</td>
<td>11,000</td>
</tr>
<tr>
<td>Floor Price(^{(1)})</td>
<td>$46.25</td>
<td>$49.77</td>
</tr>
<tr>
<td>Ceiling Price(^{(1)})</td>
<td>$53.04</td>
<td>$64.31</td>
</tr>
<tr>
<td><strong>Total Volumes Hedged</strong></td>
<td>33,000</td>
<td>26,500</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Averages are volume weighted.
### Remaining 2021 Guidance – As of November 3, 2021

<table>
<thead>
<tr>
<th></th>
<th>3Q21 Actual</th>
<th>3Q21 YTD Actual</th>
<th>4Q21 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development Capital</td>
<td>$100 million</td>
<td>$174 million</td>
<td>$75 – $95 million</td>
</tr>
<tr>
<td>Sales Volumes</td>
<td>49,682 BOE/d</td>
<td>48,732 BOE/d</td>
<td>Nearly 50,000 BOE/d</td>
</tr>
<tr>
<td>Realized Oil Differentials (NYMEX)</td>
<td>($1.75) per barrel</td>
<td>($1.44) per barrel</td>
<td>($1.50) – ($2.00) per barrel</td>
</tr>
<tr>
<td>Lifting Cost (LOE / BOE)</td>
<td>$25.50 / BOE</td>
<td>$23.21 / BOE</td>
<td>$25 – $26 / BOE</td>
</tr>
<tr>
<td>G&amp;A (total including stock compensation)</td>
<td>$15 million</td>
<td>$63 million$^{(1)}</td>
<td>$14 – $17 million</td>
</tr>
<tr>
<td>Stock Compensation</td>
<td>$3 million</td>
<td>$23 million$^{(1)}</td>
<td>$2 – $3 million</td>
</tr>
<tr>
<td>DD&amp;A</td>
<td>$38 million</td>
<td>$114 million</td>
<td>$42 – $47 million</td>
</tr>
<tr>
<td>Diluted Shares</td>
<td>54.7 million shares</td>
<td>53.4 million shares$^{(2)}</td>
<td>54 – 56 million shares$^{(2)}</td>
</tr>
</tbody>
</table>

1) G&A and Stock Compensation include $15.3 million of performance stock-based compensation related to the full vesting of outstanding performance awards during the nine months ended September 30, 2021.

2) Net loss per share (GAAP measure) is calculated using basic shares outstanding of 50.8 million shares and adjusted net income per share (non-GAAP measure) is calculated using the dilutive share count of 53.4 million shares for the nine months ending September 30, 2021. 4Q21 guidance subject to Denbury stock price.
### Senior Secured Bank Credit Facility Info

<table>
<thead>
<tr>
<th>Commitments &amp; borrowing base</th>
<th>Borrowing Base / Commitment level: $575 million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheduled redeterminations</td>
<td>Semiannually – May 1st and November 1st, next redetermination is May 2022</td>
</tr>
<tr>
<td>Maturity date</td>
<td>January 30, 2024</td>
</tr>
<tr>
<td>Permitted additional debt</td>
<td>Up to $150 million unsecured, in the aggregate, with automatic borrowing base reduction by 25% of amount borrowed</td>
</tr>
<tr>
<td></td>
<td>Junior lien debt only permitted with consent of majority lenders</td>
</tr>
<tr>
<td>Dividends and stock repurchases</td>
<td>Commencing September 18, 2021, dividend or stock repurchases 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.</td>
</tr>
<tr>
<td>Asset sales</td>
<td>Oil and gas property sales and/or hedge terminations &gt;5% of borrowing base would likely result in borrowing base reduction</td>
</tr>
<tr>
<td>Anti-hoarding provisions</td>
<td>If unrestricted cash in accounts &gt; $75 million at the end of any week, must prepay excess borrowings next business day</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pricing grid</th>
<th>Level</th>
<th>Borrowing Base Utilization</th>
<th>Libor margin(^{(1)}) (bps)</th>
<th>ABR margin (bps)</th>
<th>Undrawn pricing (bps)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>≤ 25.0%</td>
<td>300.0</td>
<td>200.0</td>
<td>50.0</td>
<td></td>
</tr>
<tr>
<td>II</td>
<td>≤ 50.0%</td>
<td>325.0</td>
<td>225.0</td>
<td>50.0</td>
<td></td>
</tr>
<tr>
<td>III</td>
<td>≤ 75.0%</td>
<td>350.0</td>
<td>250.0</td>
<td>50.0</td>
<td></td>
</tr>
<tr>
<td>IV</td>
<td>≤ 90.0%</td>
<td>375.0</td>
<td>275.0</td>
<td>50.0</td>
<td></td>
</tr>
<tr>
<td>V</td>
<td>&gt; 90.0%</td>
<td>400.0</td>
<td>300.0</td>
<td>50.0</td>
<td></td>
</tr>
</tbody>
</table>

\(^{(1)}\) Minimum LIBOR rate 1%

| 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 |
Reconciliation of Net Income (Loss) to Adjusted EBITDAX

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

<table>
<thead>
<tr>
<th>In millions</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Predecessor</td>
<td>Combined (non-GAAP)(1)</td>
</tr>
<tr>
<td>Q1</td>
<td>Q2</td>
<td>Q3</td>
</tr>
<tr>
<td>Net income (loss) (GAAP measure)</td>
<td>$74</td>
<td>$(697)</td>
</tr>
<tr>
<td>Adjustments to reconcile to Adjusted EBITDAX</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest expense</td>
<td>20</td>
<td>21</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>(11)</td>
<td>(102)</td>
</tr>
<tr>
<td>Depletion, depreciation, and amortization</td>
<td>97</td>
<td>55</td>
</tr>
<tr>
<td>Noncash fair value losses (gains) on commodity derivatives</td>
<td>(122)</td>
<td>86</td>
</tr>
<tr>
<td>Stock-based compensation</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Gain on debt extinguishment</td>
<td>(19)</td>
<td>—</td>
</tr>
<tr>
<td>Write-down of oil and natural gas properties</td>
<td>73</td>
<td>662</td>
</tr>
<tr>
<td>Reorganization items, net</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Noncash, non-recurring and other</td>
<td>2</td>
<td>13</td>
</tr>
<tr>
<td>Adjusted EBITDAX (non-GAAP measure)</td>
<td>$116</td>
<td>$39</td>
</tr>
</tbody>
</table>

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 in order to assist investors in understanding the comparability of the Company’s financial and operational results for the applicable periods. A non-GAAP measure.

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 (loss), 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 (loss), 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.