Carbon Solutions for a Sustainable Future

NYSE: DEN

May 2023

Cautionary Statements

FORWARD-LOOKING INFORMATION

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 (the “Exchange Act”), that involve a number of risks and uncertainties, particularly those regarding: possible or assumed future results of operations, cash flows, production and capital expenditures; goals and predictions as to the Company’s future carbon capture, use and storage (“CCUS”) activities; and assumptions as to oil markets or general economic conditions.

Such forward-looking statements may be or may concern, among other things, the level and volatility of posted or realized oil prices; the adequacy of our liquidity sources to support our future activities; statements or predictions related to the ultimate timing and financial impact of our proposed CCUS arrangements, including the estimated emissions storage capacity of storage sites, predictions of long-term cumulative capital investments in CCUS, the volumes of CO_2 emissions we estimate can be transported and stored, along with the timing of receipt of first revenues from storage of CO_2; our projected production levels, oil and natural gas revenues or oilfield costs; guidance ranges for various operating statement expenses for 2023: the impact of supply chain issues and inflation on our results of operations; current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows; availability, terms and financial statement and cash settlement impact of commodity derivative contracts or their predicted downside cash flow protection; forecasted drilling activity or methods, including the timing and location thereof; anticipated timing of commencement of CO_2 injections in particular fields or areas, or initial production responses in tertiary flooding projects; other development activities, finding costs, interpretation or prediction of formation details, 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 changes or proposed changes in Federal or state tax or environmental laws or regulations or of any future regulation of CO_2 pipelines; the outcomes of any pending litigation or regulatory proceedings; 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 that could significantly and adversely be affected by various factors discussed below, along with currently unknowable events beyond our control. 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 from current projections are fluctuations in worldwide or U.S. oil prices, especially in light of existing economic or geopolitical events such as the war in Ukraine; widespread inflation in economies across the world; future decisions as to production levels and/or pricing by OPEC; as to our CCUS activities, the successful completion of technical and feasibility evaluations, the raising of funds sufficient to build and operate add-on or new facilities, the pace of finalization of CCUS arrangements; and the receipt of required regulatory approval or classifications; success of our risk management techniques; 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, or other natural occurrences; conditions in the worldwide financial, trade currency and credit markets; the risks and uncertainties inherent in oil and gas drilling and production activities; and the risks and uncertainties set forth from time to time in the Company’s periodic public reports, other filings and public statements.

Statement Regarding CCUS "Agreements": References in this presentation to CCUS "Agreements" refers to both executed definitive agreements and executed term sheets or letters of intent covering various CCUS arrangements. In the case of arrangements covered by term sheets or letters of intent, those arrangements are subject to the negotiation and execution of definitive enforceable agreements.

Statement Regarding Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures pertaining to EBITDA estimates (earnings before interest, taxes, depreciation and amortization) for future periods. These projections are not reconciled to any GAAP measure given that no comparable future GAAP measures for these future periods currently exist. Management believes these projections may be helpful to investors in order to assess the Company's future CCUS activities as compared to that of other companies in the industry. These projections should not be considered in isolation, as a substitute for, or more meaningful than GAAP measures of net income (loss), cash flow from operations, or any other measure reported in accordance with GAAP.

This presentation also presents information regarding the Company’s free cash flows and its discounted estimated future net cash flows before income taxes, or PV-10 Value, of our proved oil and gas reserves, both of which are non-GAAP measures. The presentation contains reconciliations to the most directly comparable GAAP measures, along with a statement (or location of such statement in or attached to the Company’s periodic reports) as to why the Company believes such measures are beneficial to investors.

Mmtpa: Million metric tons of CO_2 per annum

DENBURY – A Unique Carbon Solutions Company

Strategic Focus
Leading in Carbon Capture, Utilization and Storage, including Enhanced Oil Recovery

20+ years Experience Managing CO_2
Safely transporting, injecting and monitoring large-scale volumes of CO_2

1300+ miles of CO_2 Pipelines
Largest owned and operated CO_2 pipeline network in the United States

Scope 3[(1)] Net Zero by 2030
Through increasing use of captured industrial-sourced CO_2

Financial Strength and Flexibility
Disciplined capital allocation, ability to organically fund growth

AT A GLANCE

Market capitalization: **$4.5 Bn**

YE22 Oil & gas proved reserves: **202 MMBOE**

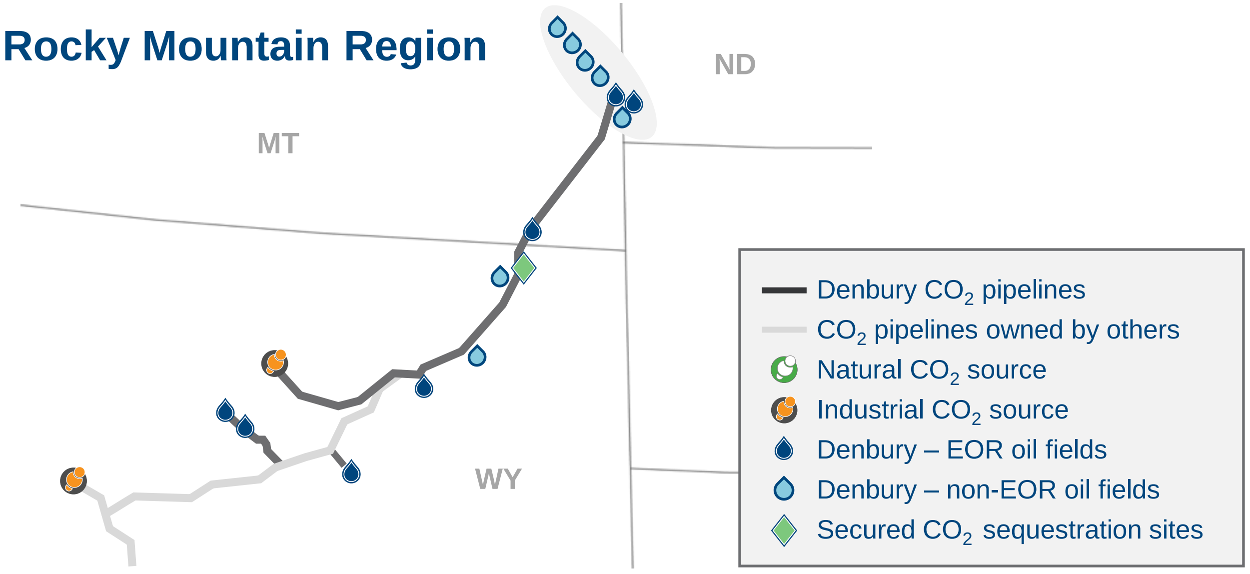
2023E Sales volumes: **46 – 49 MBOE/d**

2022 Total CO_2 sourced: **14 million metric tons; ~30% industrial**

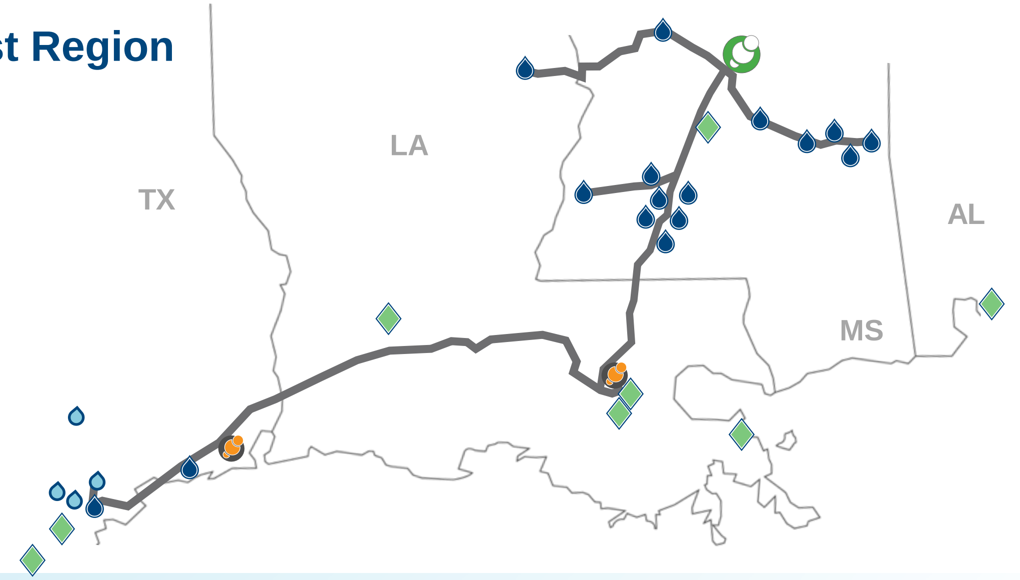
2022 Scope 1, 2 emissions: **Net negative 2.5 million metric tons**

(1) Scope 3 refers to Scope 3 Category 11 (Use of Sold Products)

Rocky Mountain Region



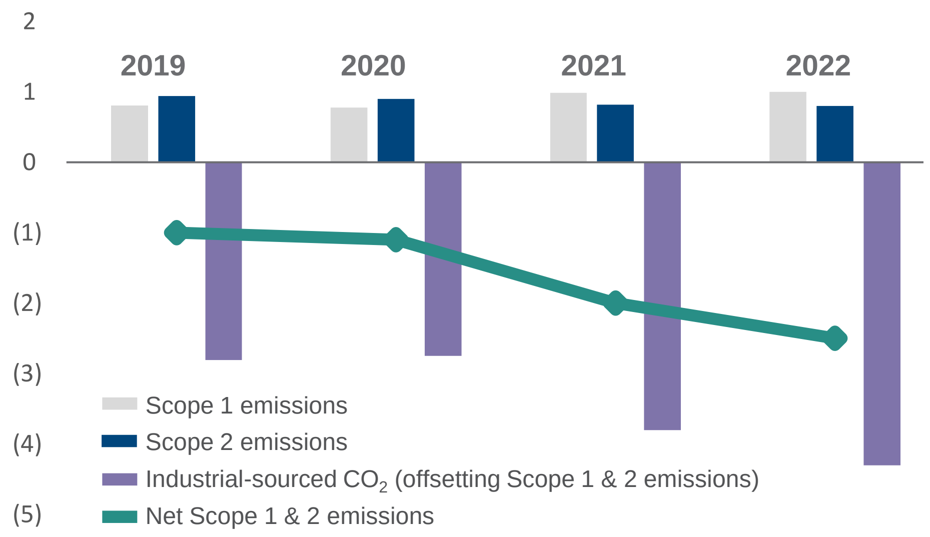
Gulf Coast Region



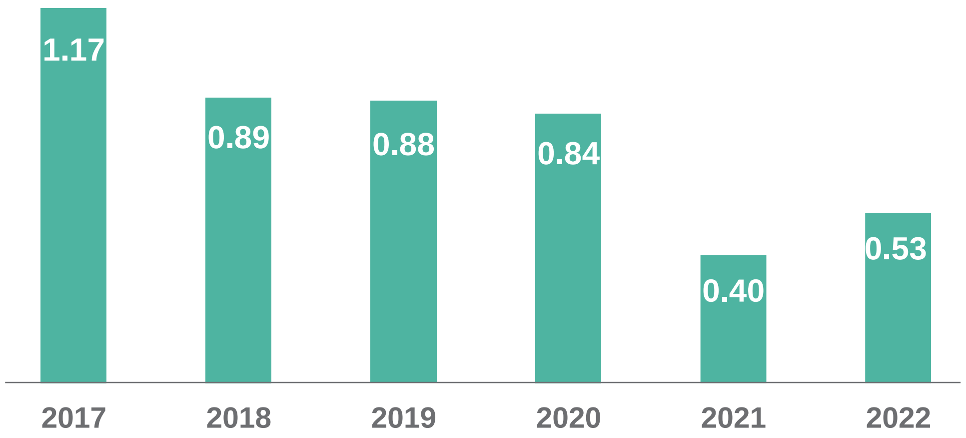
Sustainability – The Nature of Our Business

- 2022 - transported, injected and stored 4.3 million metric tons of industrial-sourced CO_2
- Delivered net negative 2.5 million metric tons Scope 1 and Scope 2 CO_2e emissions in 2022
- Achieved target of reducing Scope 1 and Scope 2 CO_2e emissions by 3% in 2022; tied to compensation
- Continued outstanding employee and contractor combined total recordable incident rate; 2022 represents 2nd lowest rate in DEN history
- 2023 ESG and TCFD Reports anticipated to be issued in the coming months

Increasingly-negative Scope 1 & 2 CO_2e Emissions
Million metric tons CO_2e



Decreasing Total Recordable Incident Rate
Incidents per 200K hours worked



Note: See details in the Company's latest Corporate Responsibility Reports on the Company website.

Denbury's 1Q23 Highlights

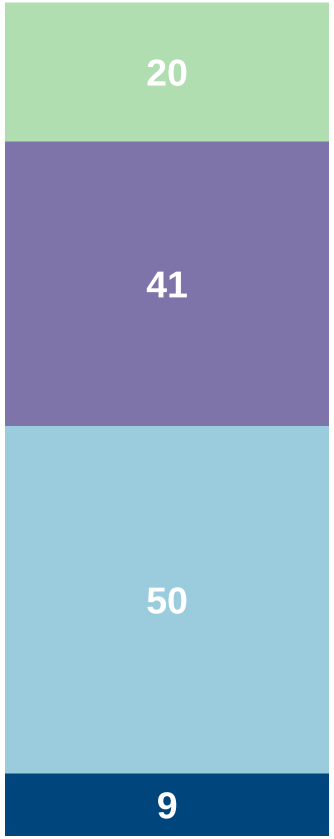
Financial	• Generated \$89 MM of cash flows from operations; adjusted cash flows from operations \$140 MM(1) • Ended 1Q23 with \$68 MM in debt and \$672 MM of financial liquidity • Cash operating margins of ~\$31 per BOE
Oil & Gas Operations	• Delivered sales of 47,655 BOE/d; in line with expectations and 2% higher than 4Q22 • Strong volumes from Oyster Bayou A2 Phase 2 development and Tinsley inventory sales • Progressed CCA EOR project with first CO_2 recycle facility commissioned in March 2023 (second currently ongoing); initial EOR production expected in 2Q23
Carbon Capture, Utilization & Storage (CCUS)	• Executed multiple eFuels agreements; cumulative agreements for future CO_2 transportation and/or storage total more than 22 Mmtpa • Secured new dedicated CO_2 sequestration site in SE Texas (April 2023); expands storage in high-emissions Houston corridor; total CO_2 sequestration portfolio now >2.1 billion metric tons • Drilled stratigraphic test well in Orion dedicated CO_2 sequestration site in Alabama for Class VI permit process • Continued success on CCUS strategic priorities; Invested \$7 MM into two emerging carbon capture technologies (ION Clean Energy and Aqualung Carbon Capture)

(1) Non-GAAP measure. See reconciliation to appropriate GAAP metric on Slide 19.

2023 Capital Spend and Sales Volume Outlook – On Plan

1Q23 Capital Spend

$MM



CCUS Capital
Orion strat test well
WY CO_2 sequestration site
Seismic licensing / other

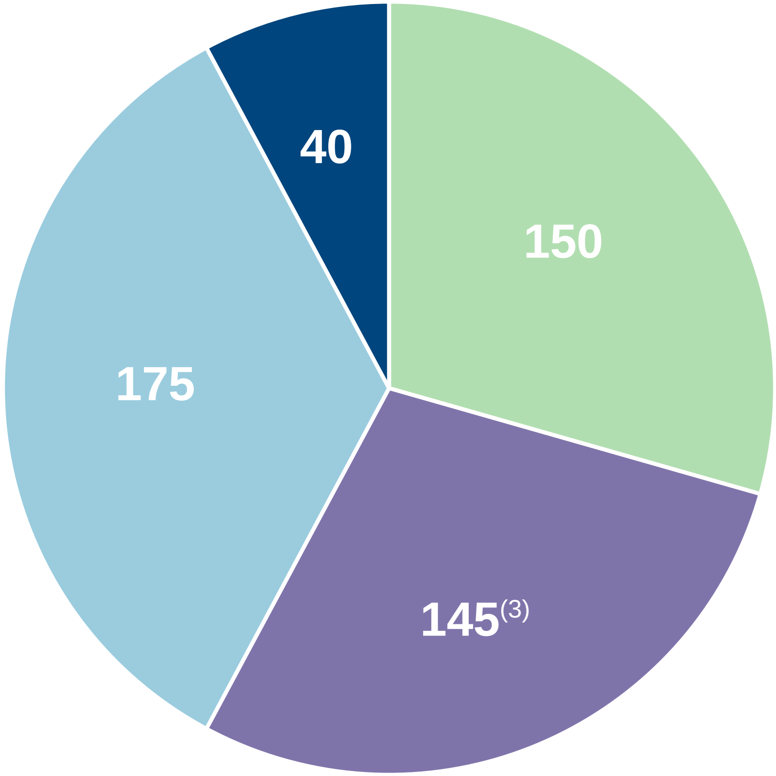
CCA CO_2 Capital
CO_2 recycle facilities
CO_2 producer conversions
Pre-production CO_2

Development Capital
Soso Rodessa Phase 2
Webster horizontals
CCA Charles horizontal

Other Capitalized Items[2]

FY 2023 Anticipated Capital ~$510 MM[1]

$MM



Sales Volumes[1]

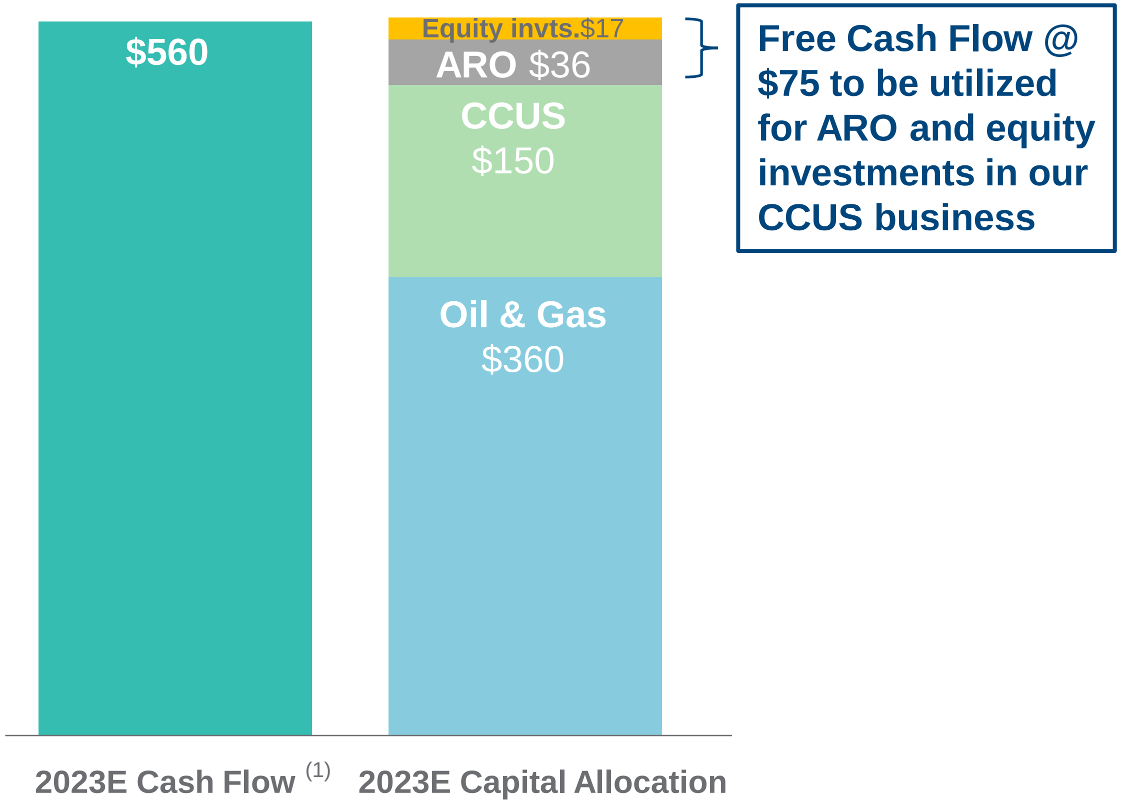
MBOE/d

2023E Volumes 46 – 49 MBOE/d

(1) Guidance as of May 3, 2023.
(2) Includes capitalized internal acquisition, CO_2 sources and non-CCA pipeline and pre-production tertiary startup costs.
(3) Includes pre-production capitalized CO_2 estimated at $15MM in 2023

2023 Outlook DEN Capital Allocation Priorities

2023E Cash Flow from Operations and Capital Allocation
$MM



(1) $75/bbl WTI price assumption excluding hedges

Capital Allocation Priorities

1. **Maintain Strong Balance Sheet**
   Ended 1Q23 with $68 MM in debt; $672 MM financial liquidity (cash and available borrowings)
2. **Sustain Production / Deliver CCA**
   Continue to invest for modest long-term oil growth through CCA
3. **Fund CCUS Development**
   Increased capital spend in 2023 - focus on developing dedicated CO_2 storage portfolio
4. **Return Capital to Shareholders**
   when prices are significantly above $75 per Bbl; 100 MM share buyback in 2022

Oil & Gas Operations – Gulf Coast Region

1Q23 Highlights

Oyster Bayou – strong production response from Frio A2 phase 2 development

Soso – completed Phase 2 Rodessa development, expected response 3Q23

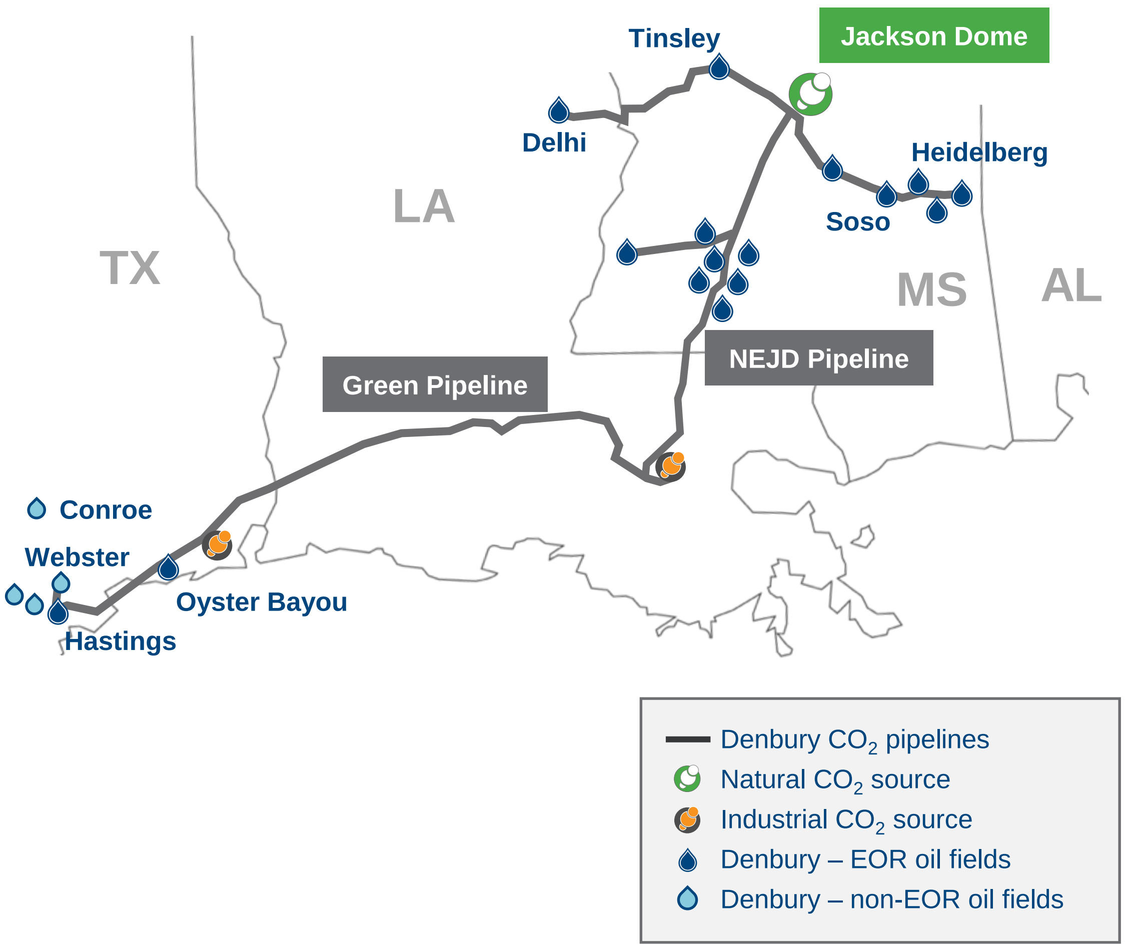
Webster – drilled and commenced production on 4 horizontal wells

Asset retirement – proactively plugged & abandoned 34 wells in 1Q23

1Q23 Statistics

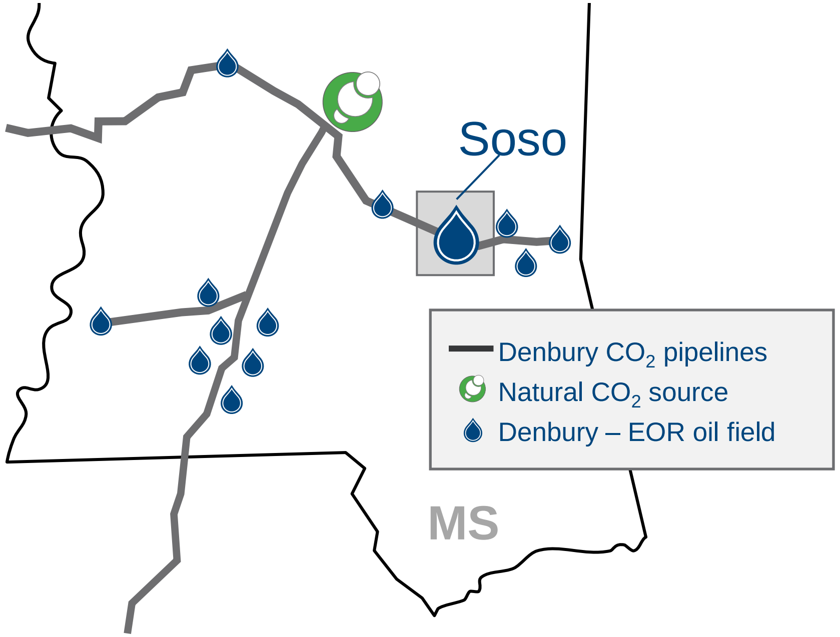
Sales volume (BOE/d)	**26,524**
CO_2 utilized (million metric tons)	**2.0**
– % industrial	**14%**
Capital expenditures[(1)] ($MM)	**23**
YE22 proved reserves (MMBOE)	**113**

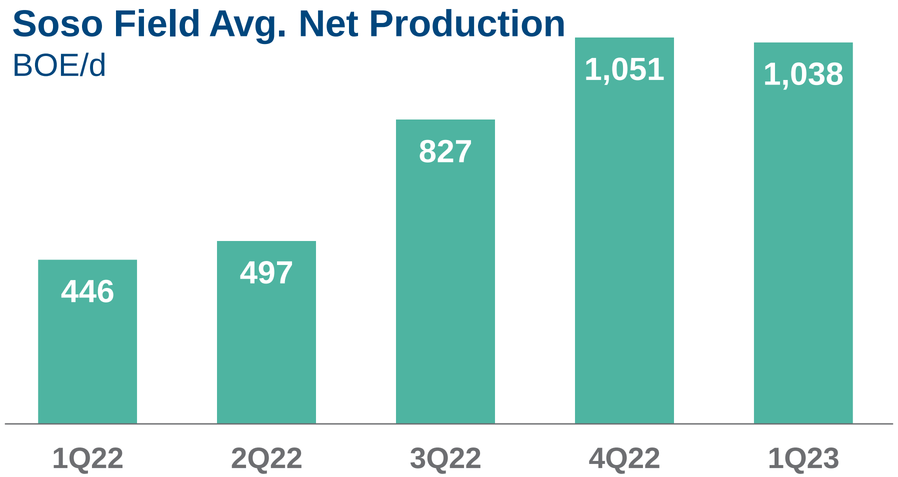
(1) Excludes capitalized internal costs and inventory.

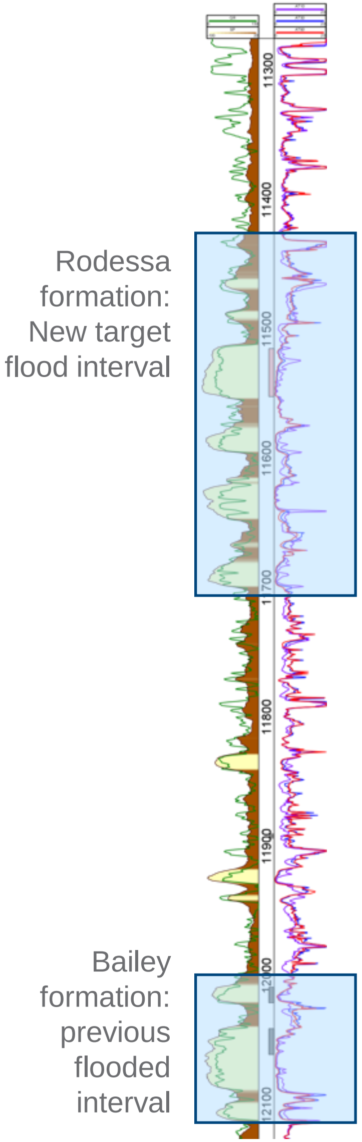


Soso Field (MS) – Revitalizing Mature Assets

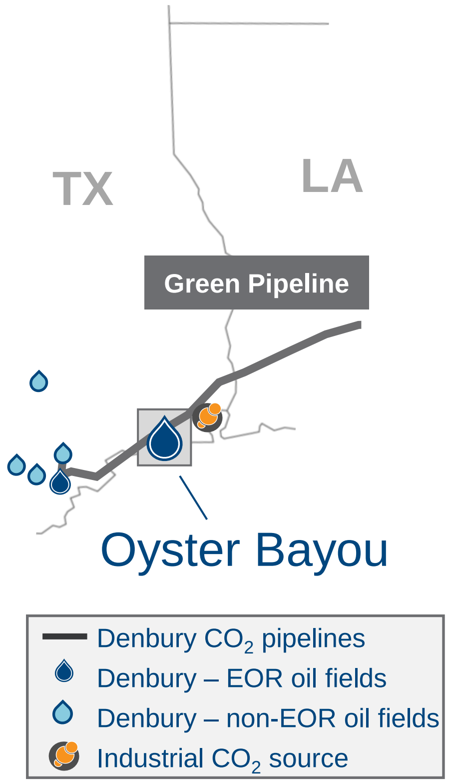
- **2022 Highlights – Phase 1**
  - Net production up 135% in 2022
  - Recompleted 9 vertical oil producers and 4 CO_2 injectors into the Rodessa interval to develop a new horizon for CO_2 flooding by utilizing existing CO_2 infrastructure
  - Net capital spend for Phase 1 ~$13 MM
- **Future Development**
  - Phase 2 expansion started early 2023 with an additional 6 wells to be recompleted in the Rodessa formation
  - Additional potential future phases







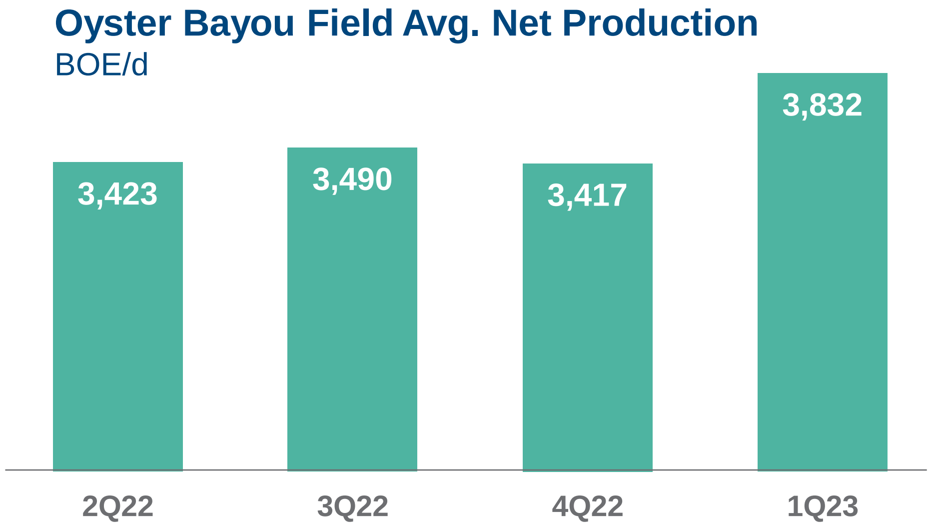
Oyster Bayou Field (TX) – A2 Phase 2 Development



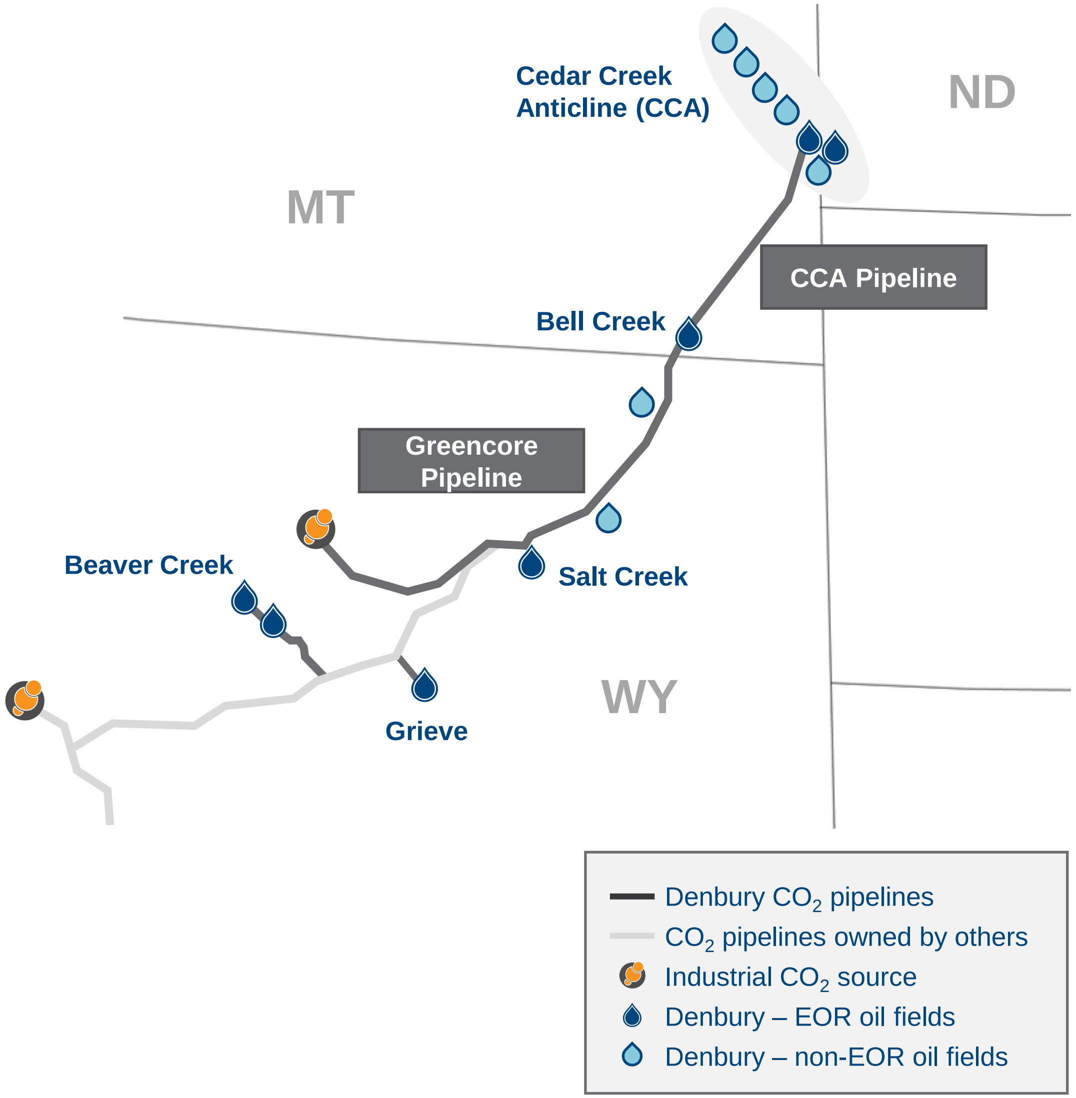
Encouraging Frio A2 Phase 2 Development Response

- Converted two existing wells to CO_2 injection and drilled one new CO_2 injector and two new oil producers
- First injection September 2022 with first oil response January 2023
- Net field production up >400 BOE/d from project response
- Net capital spend ~$10.5 MM

Additional Development Opportunities in 2024 / 2025



Oil & Gas Operations – Rocky Mountain Region



1Q23 Highlights

CCA (Cabin Creek) – waterflood pilot development in the Charles formation (2 new drill production wells and 1 injection well)

CCA EOR development – construction of 4 CO_2 recycle facilities; downhole producer conversions for CO_2 operations

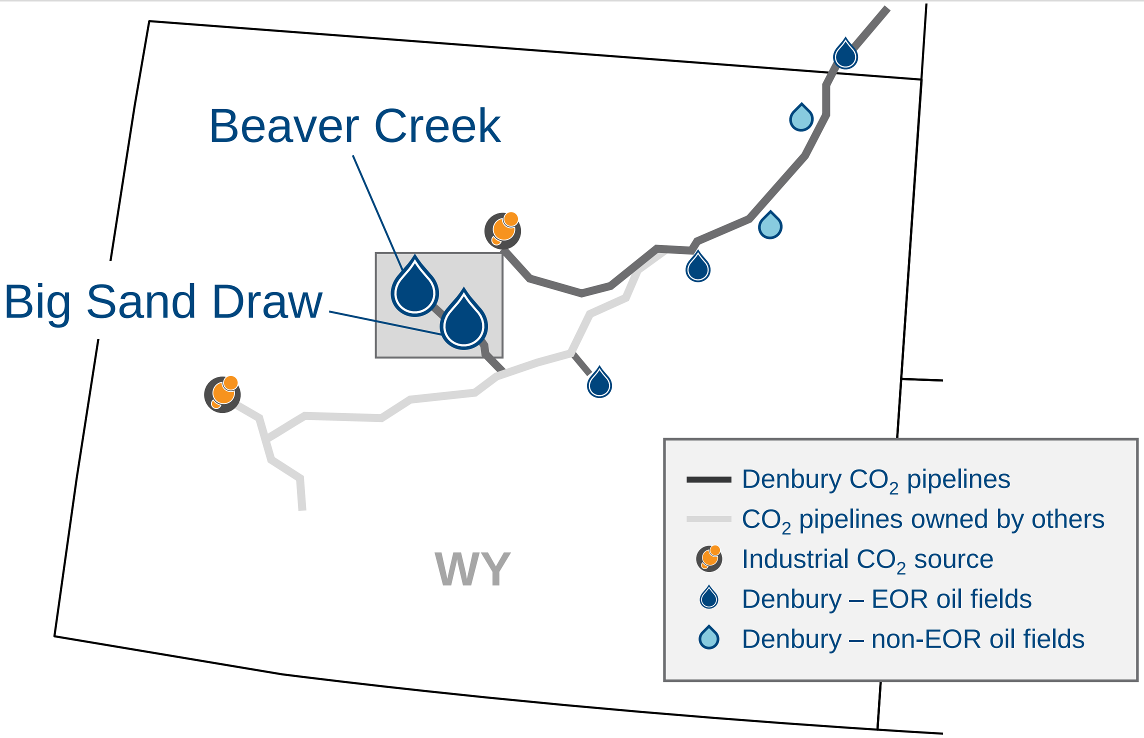
Wind River Basin – continued strong production response in Beaver Creek from Madison E/F development and reservoir management optimization

1Q23 Statistics

Sales volume (BOE/d)	**21,132**
CO_2 utilized (million metric tons)	**0.9**
– % industrial	**100%**
Capital expenditures[(1)] ($MM)	**65**
YE22 proved reserves (MMBOE)	**89**

(1) Excludes capitalized internal costs and inventory.

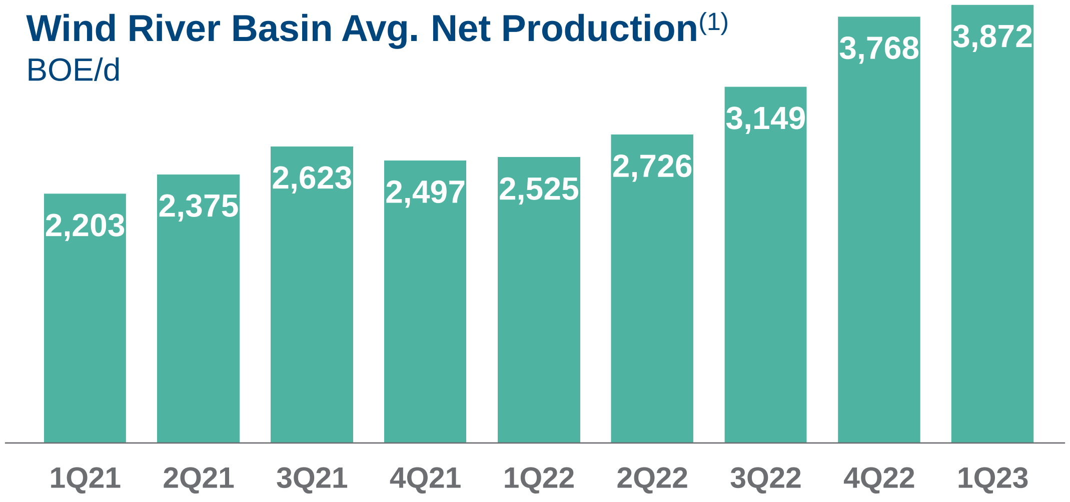
Wind River (WY) – Significant Value Increase Post Acquisition



- **Acquired in March 2021 for $20 MM**
  - $12 MM original purchase price plus oil-linked contingency
  - Two active CO_2 floods (Big Sand Draw and Beaver Creek) producing 2.6 MBOE/d
  - 46 miles of CO_2 pipeline and other infield CO_2 infrastructure

- **2022 Highlights**
  - Quarterly high production in 1Q23; up 75% from level when acquired in March 2021
  - Beaver Creek: executed Madison E/F reservoir project
  - Net capital spend Madison E/F ~$11 MM
  - Big Sand Draw: recompleted downdip wells for additional oil response
- **Future Development**
  - Infill drilling at Beaver Creek planned for 2H23 and pilot project in Big Sand Draw targeting incremental oil recovery

Wind River Basin Avg. Net Production(1)
BOE/d



(1) Net production does not include non-tertiary field production

World-class Cedar Creek Anticline EOR Development

Largest CO_2 Flood in DEN History

- Estimated total recoverable resource of >400 MMBbls

Drives Total Company Production Growth in 2024

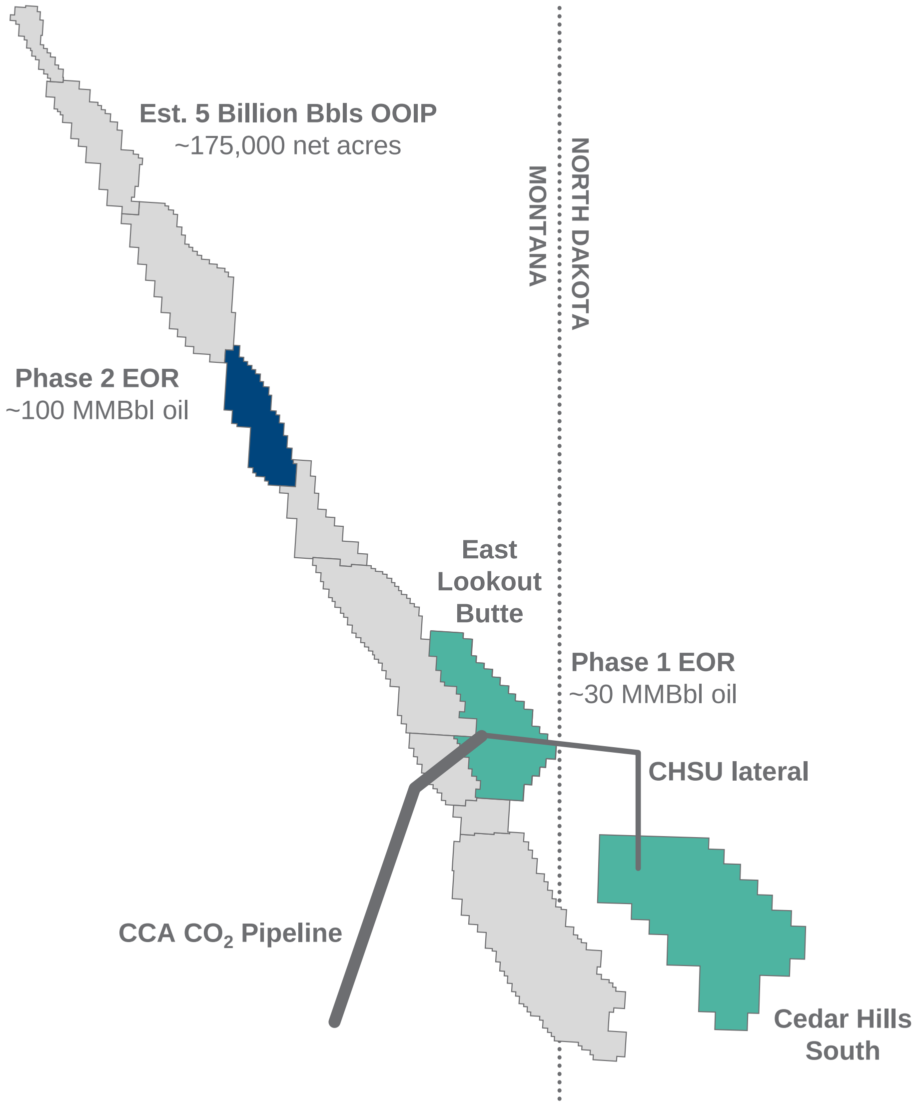
- Peak production from Phase 1 of 7.5 - 12.5 MBbl/d

Lowers Operating Costs over Life of Field

- Anticipate $10 - 15 LOE/BOE after full field ramp

100% Carbon-negative Development

- Net negative Scope 1 / 2 / 3 emissions[(1)]

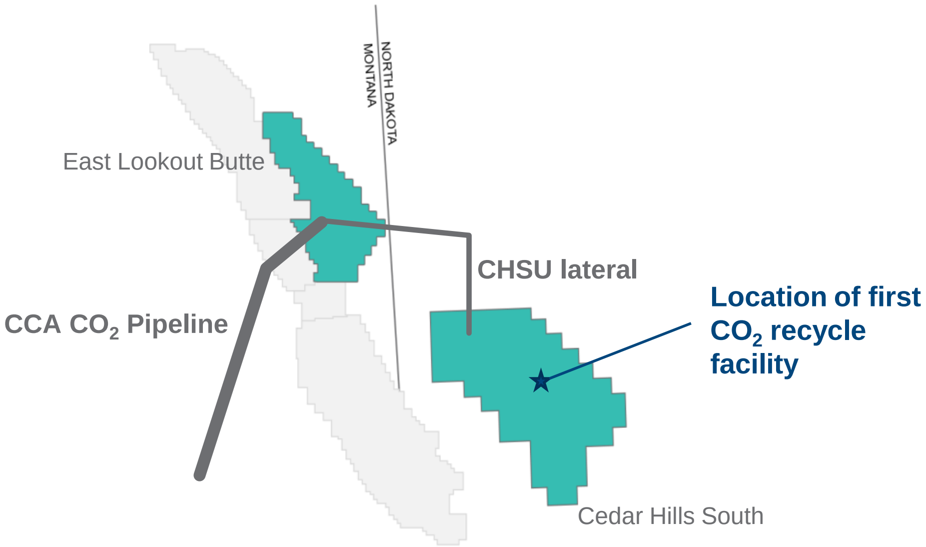


(1) Scope 3 refers to Scope 3 Category 11 (Use of Sold Products)

CCA EOR – Initial Phase 1 Response Expected in 2Q23

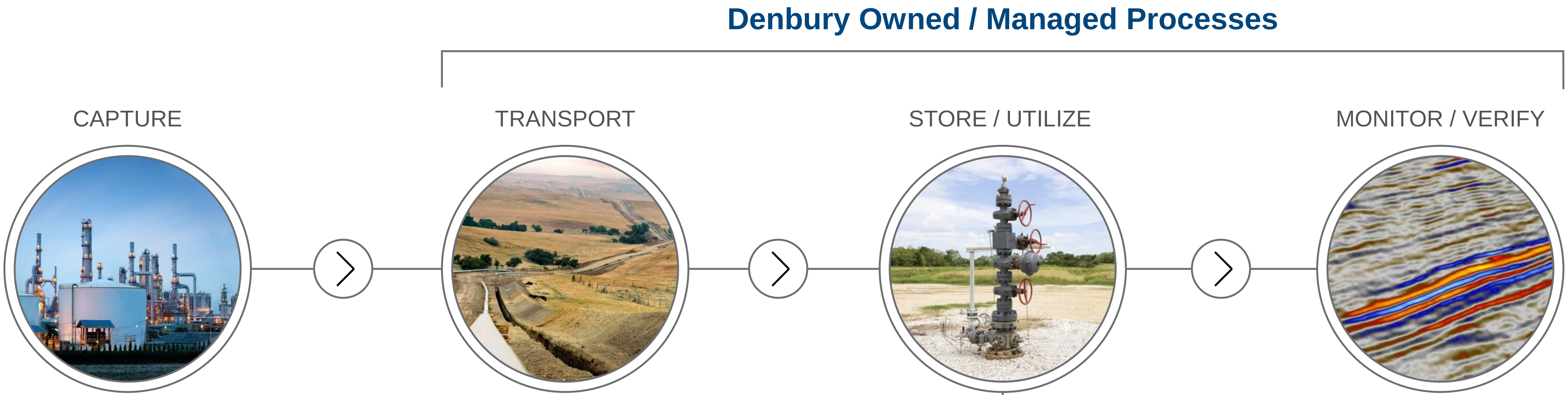
First EOR CO_2 Recycle Facility Commissioned in March 2023; Second Began Commissioning April 2023

- Ongoing construction of 2 additional recycle facilities; commissioning expected to begin late 3Q23
- Curtailed slightly more than 500 Bbl/d (1Q23 avg.) awaiting CO_2 recycle facilities
- Expect 2023 exit rate of 2,000 Bbl/d incremental EOR production

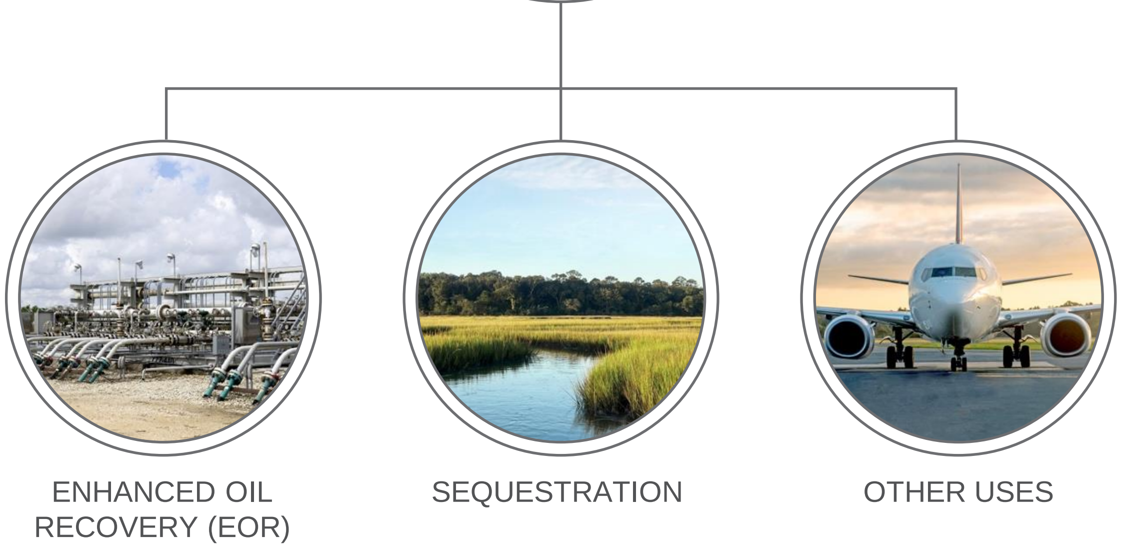


Cedar Hills South first recycle facility and CO_2 compressor

CCUS – A Proven Pathway to Significantly Reduce CO_2 Emissions



CCUS is an effective, low-cost solution using proven technology to capture CO_2 emissions and either inject them permanently underground or use them in creating various products



2023 CCUS Goals

Continue to Capture CO_2 Emissions Market

- Secure additional agreements in 2023 from both brownfield and greenfield projects
- Cumulative agreements at the end of 2023 to total in excess of 30 Mmtpa

Expand Dedicated Storage Portfolio

- Plans to secure additional CO_2 storage sites in strategic locations; potentially new markets
- Expand existing sequestration sites with nearby leasing

Enhance CCUS Partnerships

- Invest in multiple carbon capture technology companies
- Continue to assess JV/strategic relationships to expand CCUS opportunities

Advance Class VI Permitting and Ready for Injection

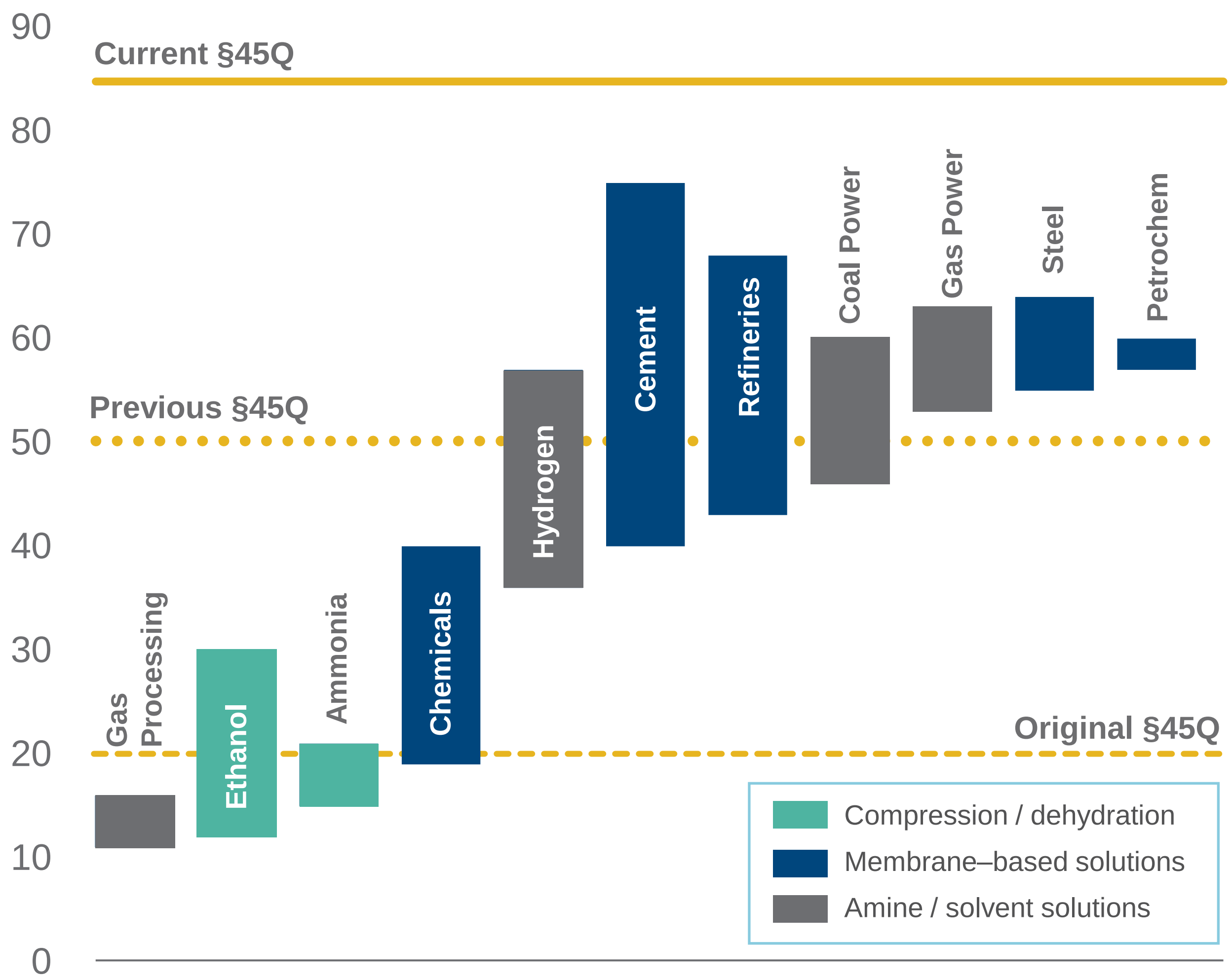
- Submit Class VI permits on 4 additional dedicated CO_2 storage sites
- Drill at least 2 stratigraphic test wells to support Class VI injection

Increasing CCUS Scale With IRA and Technology

- **New technologies and enhanced §45Q levels ($35 / $50 to $60 / $85 per tonne) bring post-combustion emissions into economic capture window**
- **Emerging technologies driving down the cost of CO_2 capture by up to 40%**
  - Membrane-based technologies offer lower cost of capture for lower volume levels
  - Liquid technologies (solvent-based) offer lower cost of capture at higher volumes; benefit from economies of scale
- **DEN equity investments / partnerships with two CO_2 capture technology companies**
  - Insights into capture technology innovation
  - Increases potential transportation and storage opportunities

Industry Capture Cost per Metric Ton

$ per tonne



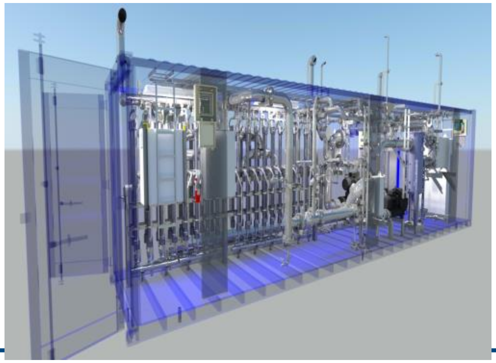
Source: Great Plains Institute, *Transport Infrastructure for Carbon Capture and Storage*

DEN Investments in Innovative Capture Technologies

ION CLEAN ENERGY

- Advanced liquid absorption technologies in ICE-21 and ICE-31
- Significantly reduced cost structure
  - At least 95% capture efficiency
  - Extremely low emissions; low energy requirements
  - Faster solvent kinetics
  - Unprecedented solvent stability
- Target emitters:
  - Large scale post combustion > 500,000 mtpa
  - Developing modular capture units for smaller scale

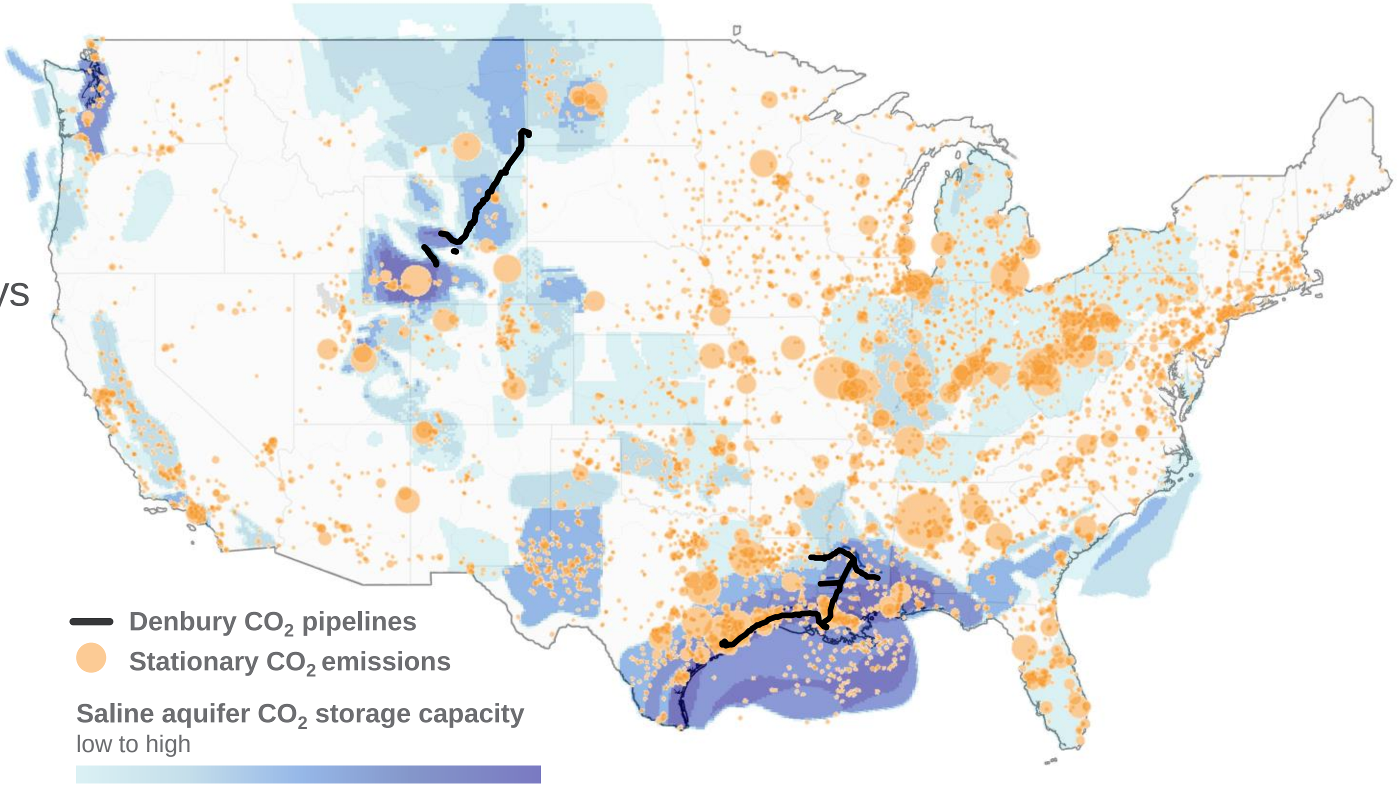
aqualung



- Hybrid facilitated transport membrane
- Lowest capture costs of membrane technologies
  - Patented coating process drives passive CO_2 separation resulting in substantial energy savings
  - Technology utilizes commercially available membrane capacity which materially drives down capital costs
  - Highly compact and fully scalable
- Target emitters:
  - <100,000 to 500,000+ mtpa
  - Low CO2 concentration (3.5%) to high (30%+)

U.S. Gulf Coast – A World-class CCUS Opportunity

- **The Gulf Coast has one of the highest concentrations of stationary CO_2 emissions**
- **Advantaged for greenfield projects**
  - Access to low-cost natural gas feedstock, waterways and deepwater ports, supportive regulatory policy
- **Expandable CO_2 pipeline infrastructure already in place**
  - DEN has the only dedicated CO_2 pipeline network in the Gulf Coast at >900 miles
- **High-quality geology for secure long-term storage of CO_2**
  - Large reservoirs and high injectivity
  - Approximately 5 trillion tonnes potential storage capacity in the U.S. Gulf Coast



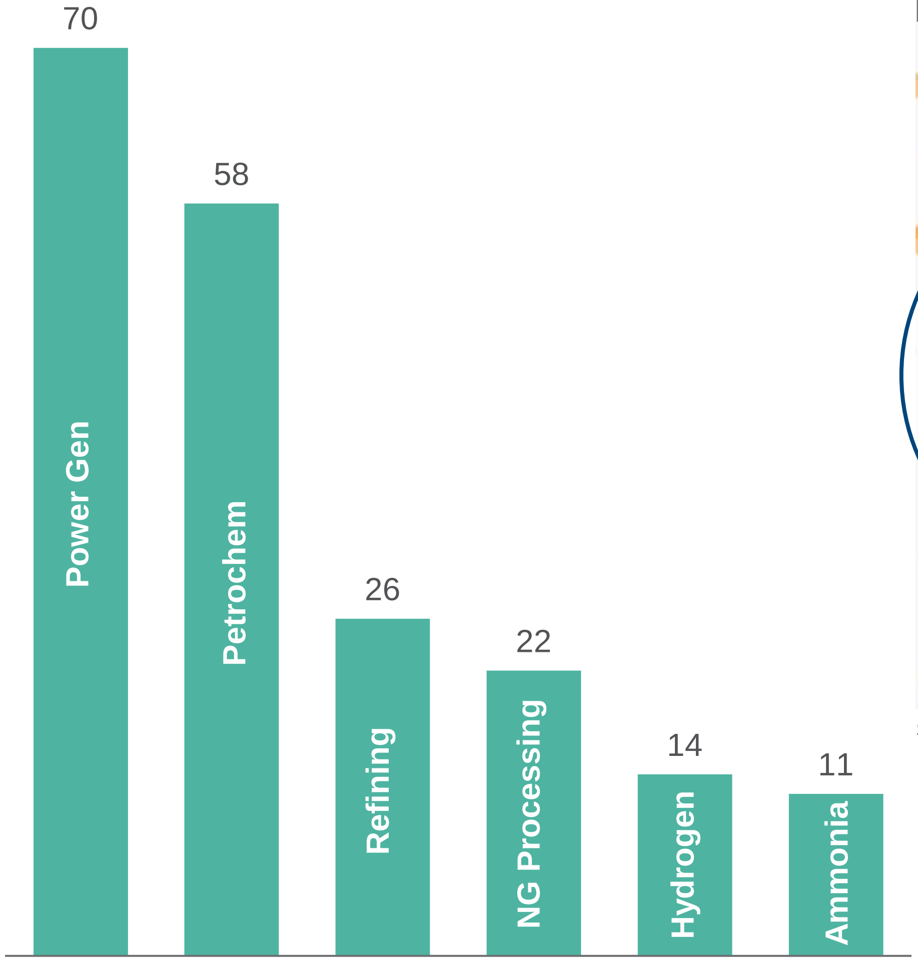
~240 Mmtpa emissions within 30 miles of DEN Gulf Coast system

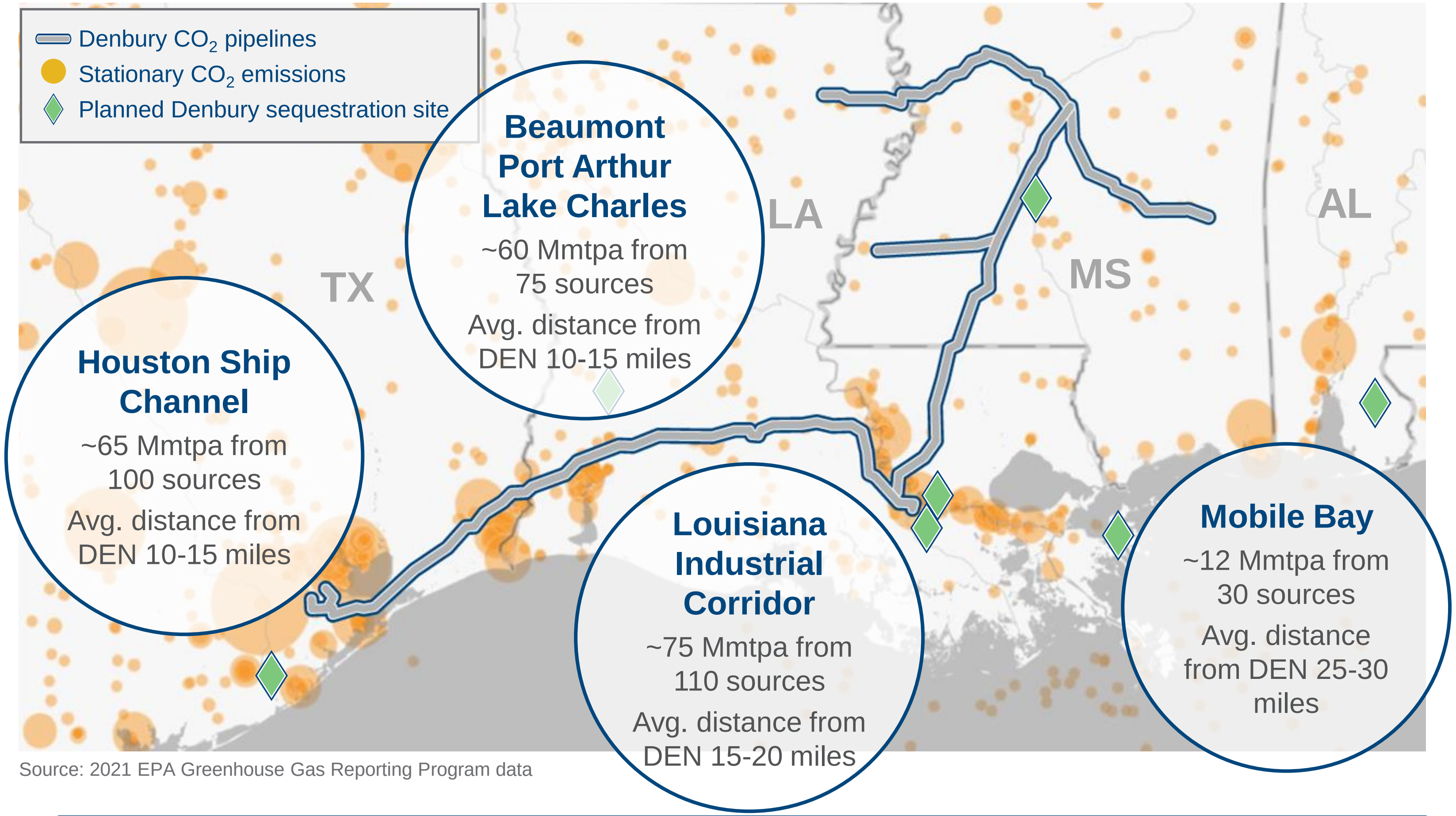
Source: 2021 EPA Greenhouse Gas Reporting Program data, National Energy Technology Laboratory: 1NATCARB Medium (P50) saline aquifer CO_2 storage capacity , Great Plains Institute, *Transport Infrastructure for Carbon Capture and Storage*

U.S. Gulf Coast – Major Source of Existing CO_2 Emissions

U.S. Gulf Coast Emissions w/in 30 Miles of DEN Pipelines

CO_2 (Mmtpa)



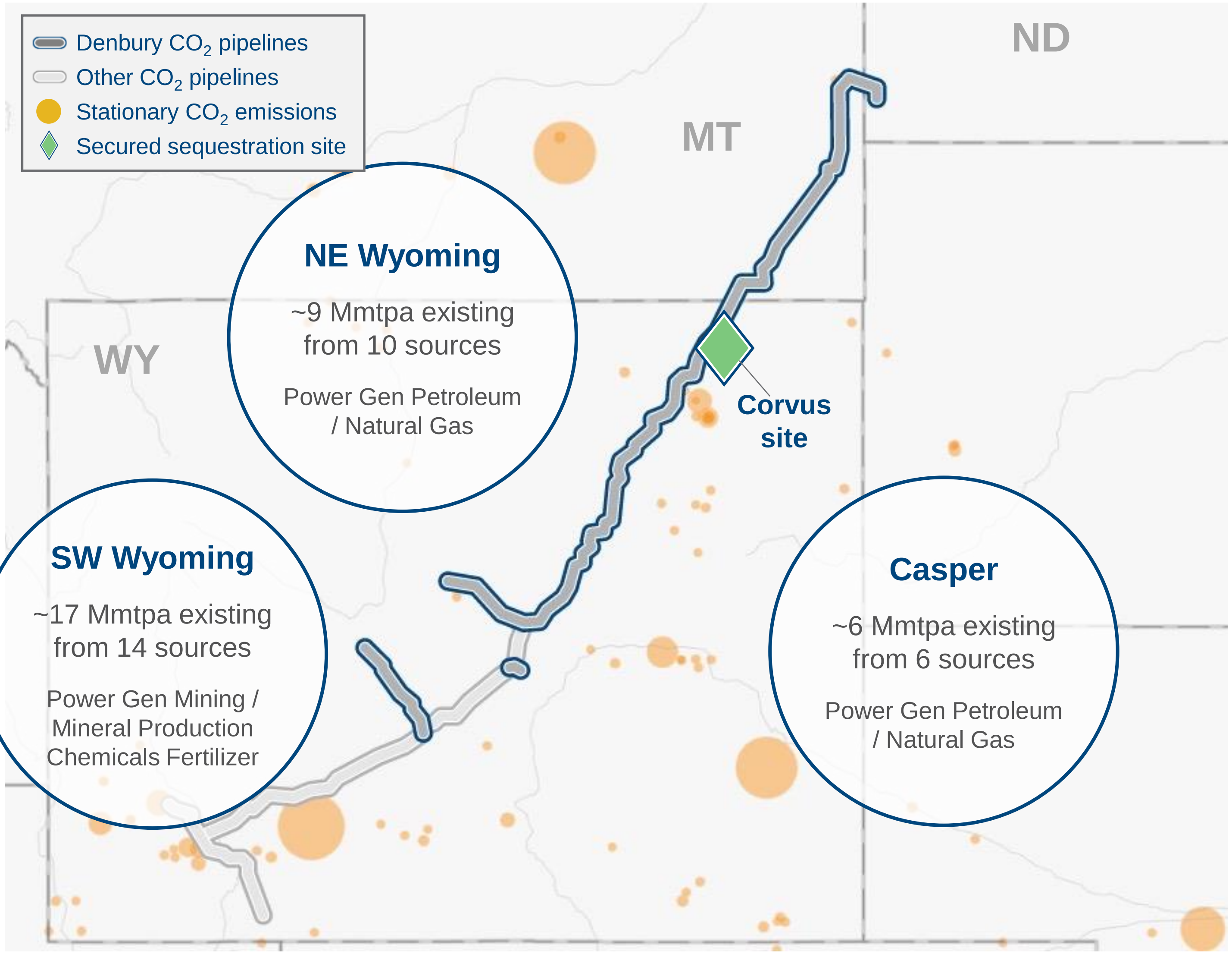


Source: 2021 EPA Greenhouse Gas Reporting Program data

~240 Mmtpa within 30 miles of DEN Gulf Coast system; provides unique transportation and storage opportunities

Rocky Mountains – An Emerging CCUS Opportunity

- **Acquired initial CO_2 sequestration site (Corvus) in Wyoming for future storage**
  - 15,000-acre site located directly under Denbury Greencore CO_2 pipeline
  - Estimated potential CO_2 storage capacity of 40 million metric tons
- **Nearby emissions primarily from power generation**
  - 9 Mmtpa existing with multiple proposed greenfield projects
  - DEN signed agreement for Wyoming hydrogen newbuild w/ up to 1 Mmtpa CO_2
- **Future potential CO_2 sources include SW Wyoming and Casper**



Source: 2021 EPA Greenhouse Gas Reporting Program data

CCUS Commercial Structures

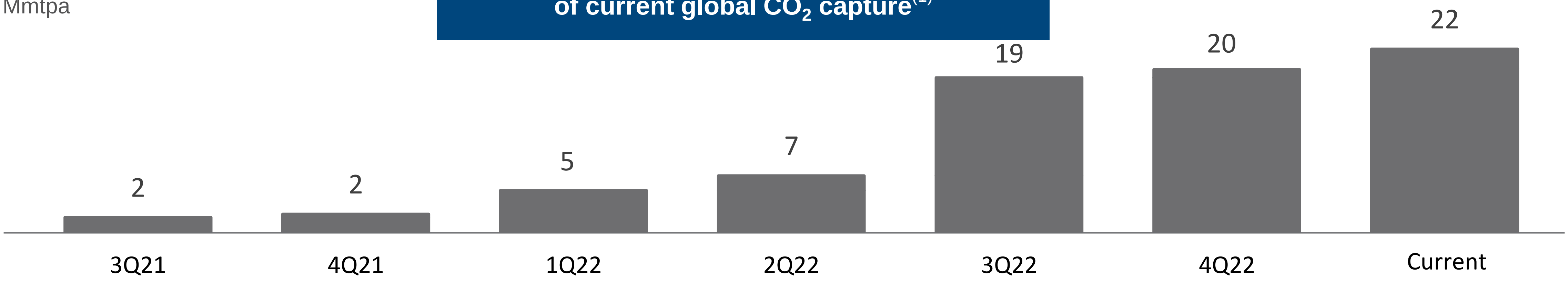
Types of Emissions Agreements	Transportation	Transportation & Storage	Capture, Transportation, Storage
	Leverage DEN pipeline system to move CO_2 to 3rd party storage	**Connect lateral to industrial customer; move CO_2 to DEN owned and operated secure storage**	**Turnkey operation for customers who prefer full-service solution**
% of anticipated DEN volumes	5 – 10%	80 – 90%	5 – 10%
Agreements announced (million metric tons per year)	4	18.5	–
Anticipated avg. revenue ($/tonne)	$5 – 15	$15 – 25 (sequestration) $0 – 10 (EOR)	$85 §45Q (less market-priced fee paid to industrial customer)
Term length (years)	Up to 20	12 – 20	12+ (§45Q term)
Capital intensity	Low	Medium	High

Note: Anticipated revenue per agreement subject to pipeline capital costs and §45Q levels.

22 Mmtpa Under Existing Transport & Storage Agreements

CO_2 Emissions Agreements
Mmtpa

DEN announced contracts equivalent to ~50% of current global CO_2 capture[(1)]



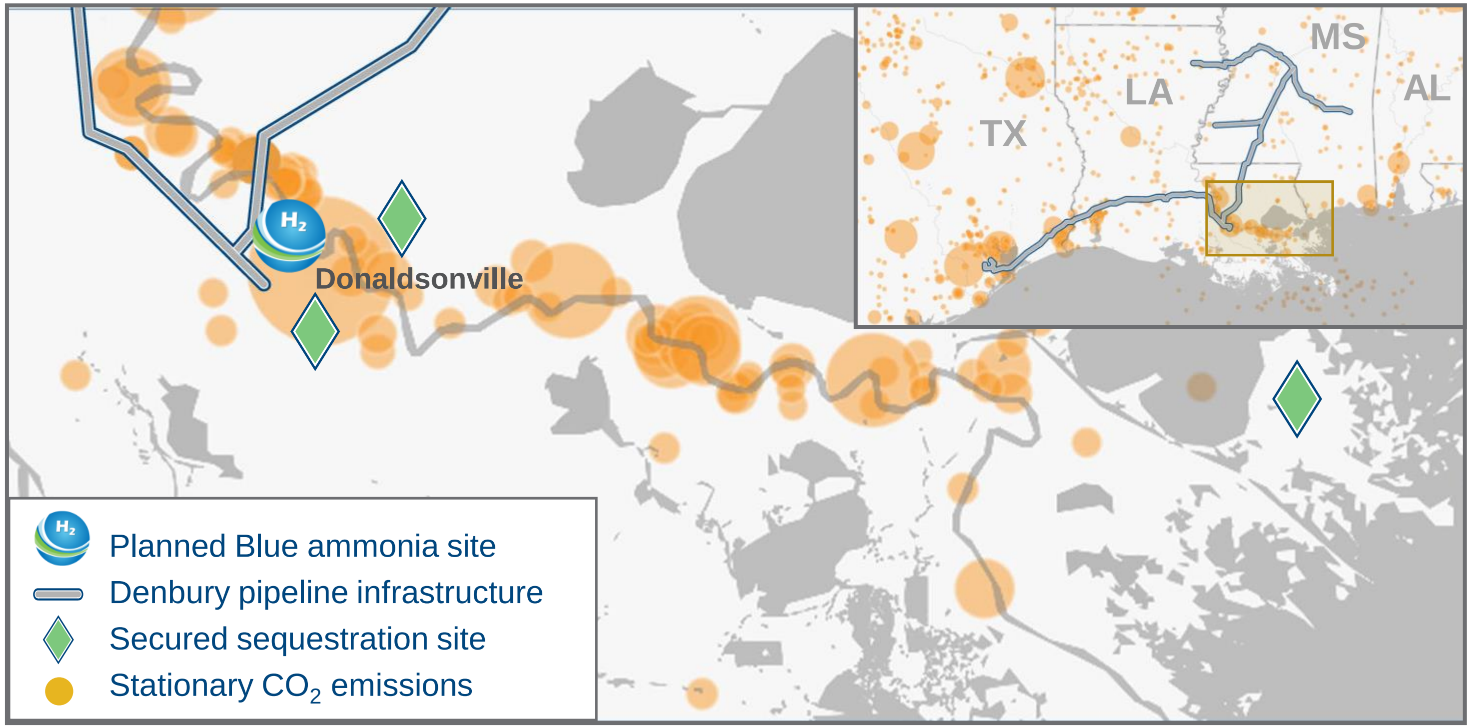
DEN executed agreements	Planned location	Industry type	CO_2 volume (Mmtpa)	Expected start date
Wyoming hydrogen facility	WY	Hydrogen	Up to 1	2024 / 2025
Infinium	S TX	Low carbon fuels	1.5	2025
Gulf Coast biofuels facility	S TX	Biofuels	Up to 1	2025
Louisiana chemicals facility	LA	Chemical plant	0.4	2025
Monarch Energy Development	S TX	eFuels	0.4	2026
Nutrien	SE LA	Blue ammonia	1.8	2027
Mitsubishi	LA	Blue ammonia	1.8	Second half of decade
Lake Charles Methanol	LA	Blue methanol	1	2027
Clean Hydrogen Works	SE LA	Blue ammonia	Up to 12	2027 (initial phase)
HIF Global	S TX	eFuels	2	2027

(1) Global carbon capture of 43 million metric tons in 2021 per IEA World Energy Outlook 2022

Clean Hydrogen Works – Ascension Clean Energy Project

- **Planned to be one of the largest "Blue Ammonia" complexes in the world**
  - 7.2 million tons per year of ammonia (2 Blocks)
  - CO_2 offtake volume up to 12 Mmtpa
  - 12-year term agreement; Start date 2027 (1st Block)
- **DEN equity owner in the ACE project with $20 MM investment**

80% of Ammonia Offtake Under LOI w/ Large International Buyers



Source: 2021 EPA Greenhouse Gas Reporting Program data

Block 1 Timeline

1,700-acre site – West bank of Mississippi River in Donaldsonville

FEED Study Sign Offtake Agreements Secure Capital Commitment	Final Design & Construction	On Production

2024
Final investment decision

2027
Plant commission & start up

DEN Competitive Advantage – CO_2 Transport

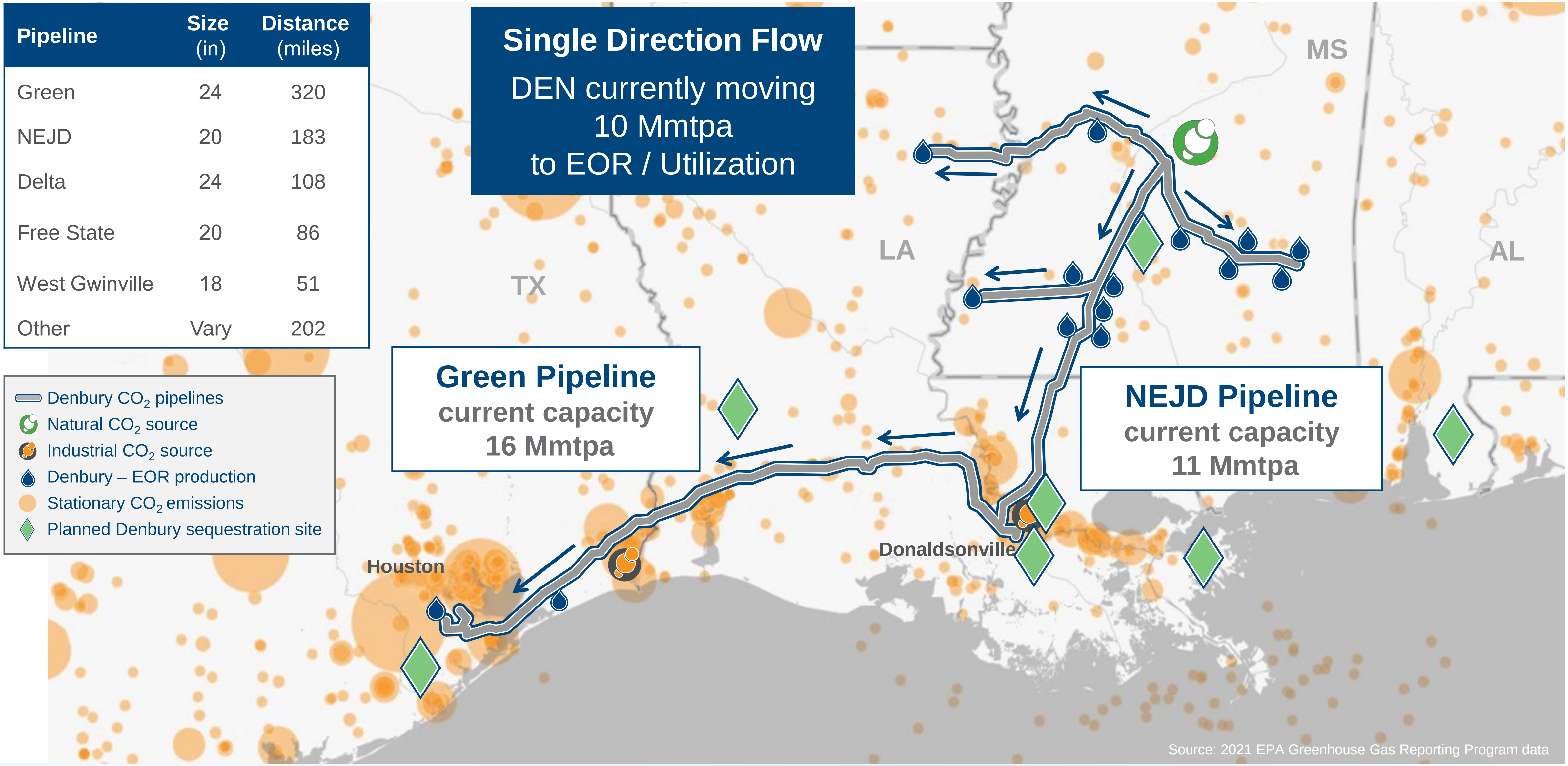
- **>1,300 miles of existing DEN CO_2 pipelines (approximately 25%[(1)] of existing U.S. total)**
  - Specifically built for purpose of moving CO_2
  - High efficiency and flexibility through supercritical operating pressure (ANSI 900)
- **Transport capacity of current network and future planned expansions ~150 Mmtpa**
  - Capacity expansions of existing pipelines through pump stations and line looping in heavy emissions areas
  - Future extensions of major DEN pipelines along Texas Gulf Coast, to New Orleans and SW Alabama
- **Unparalleled redundancy and reliability for industrial customers**
  - Proven reliability over 20+ years of operation; nearly 100% uptime
  - CO_2 fungibility to balance entire system between multiple emissions sources and offtake locations to EOR / sequestration

Note: Picture highlights 2021 installation of CCA CO_2 pipeline in Rocky Mountain region

(1) Per 2021 National Petroleum Council Report, *Meeting the Dual Challenge*

Current Flow of CO_2 Through DEN Gulf Coast Pipeline System

Pipeline	Size (in)	Distance (miles)
Green	24	320
NEJD	20	183
Delta	24	108
Free State	20	86
West Gwinville	18	51
Other	Vary	202



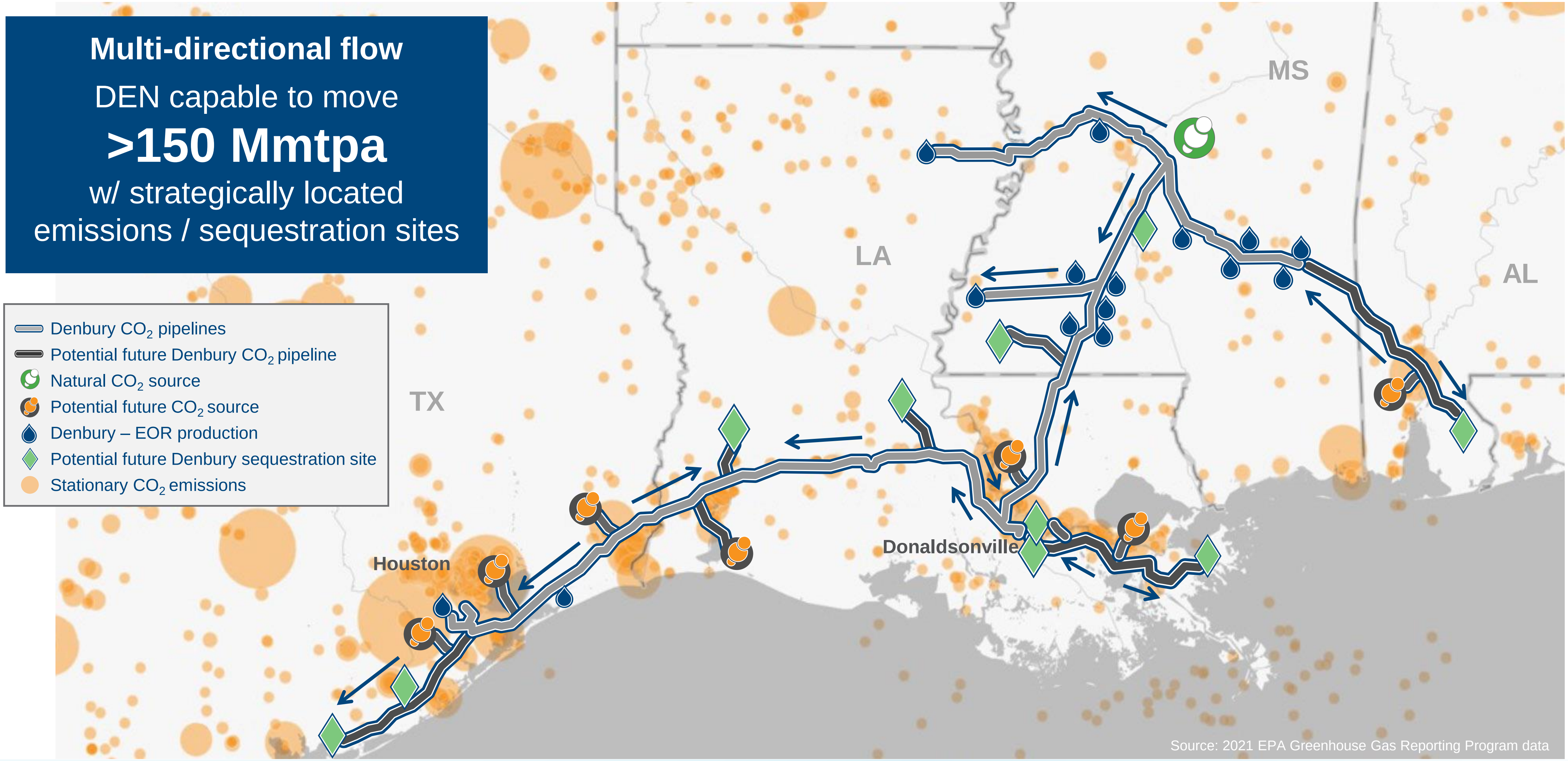
Future Potential – Optimized Network to Maximize CO_2 Flows

Multi-directional flow

DEN capable to move

>150 Mmtpa

w/ strategically located emissions / sequestration sites



Source: 2021 EPA Greenhouse Gas Reporting Program data

DEN Competitive Advantage – CO_2 Storage

- **20+ years of CO_2 injection and monitoring through EOR underpins technical leadership**
  - Multiple large-scale EOR developments and CO_2 pipeline projects
  - Extensive subsurface modeling and monitoring skillsets used in EOR is highly adaptable to CCUS
  - Currently operate >750 CO_2 injection wells
- **8 sequestration sites with >2 B metric tons in U.S. Gulf Coast CO_2 storage potential**
  - Strategically positioned to expand network capacity
  - Recently-added sequestration site in Wyoming under Greencore Pipeline
- **Submitted Class VI permits on 2 Sites (AL, MS) and anticipate multiple additional submittals in early 2023**
  - Ongoing engagement with EPA
  - Drilled initial stratigraphic test well (AL); anticipate drilling 2-4 more in th 2023 (LA, MS, TX)

EOR Provides Large-scale CO_2 Associated Storage Today

- **More than 20 active EOR floods connected to DEN pipeline infrastructure**
  - Cedar Creek Anticline EOR began injection in 1H22 (anticipated production response in 2H23)
- **DEN Class II injection for 2021 totaled approximately 70 Mmtpa (recycled volumes and new purchase)**
- **DEN EOR has resulted in cumulative associated storage of >225 million metric tons of CO_2**
- **Over 400 million metric tons of future CO_2 utilization potential in our EOR fields**

The Most Environmentally Friendly Oil on the Planet

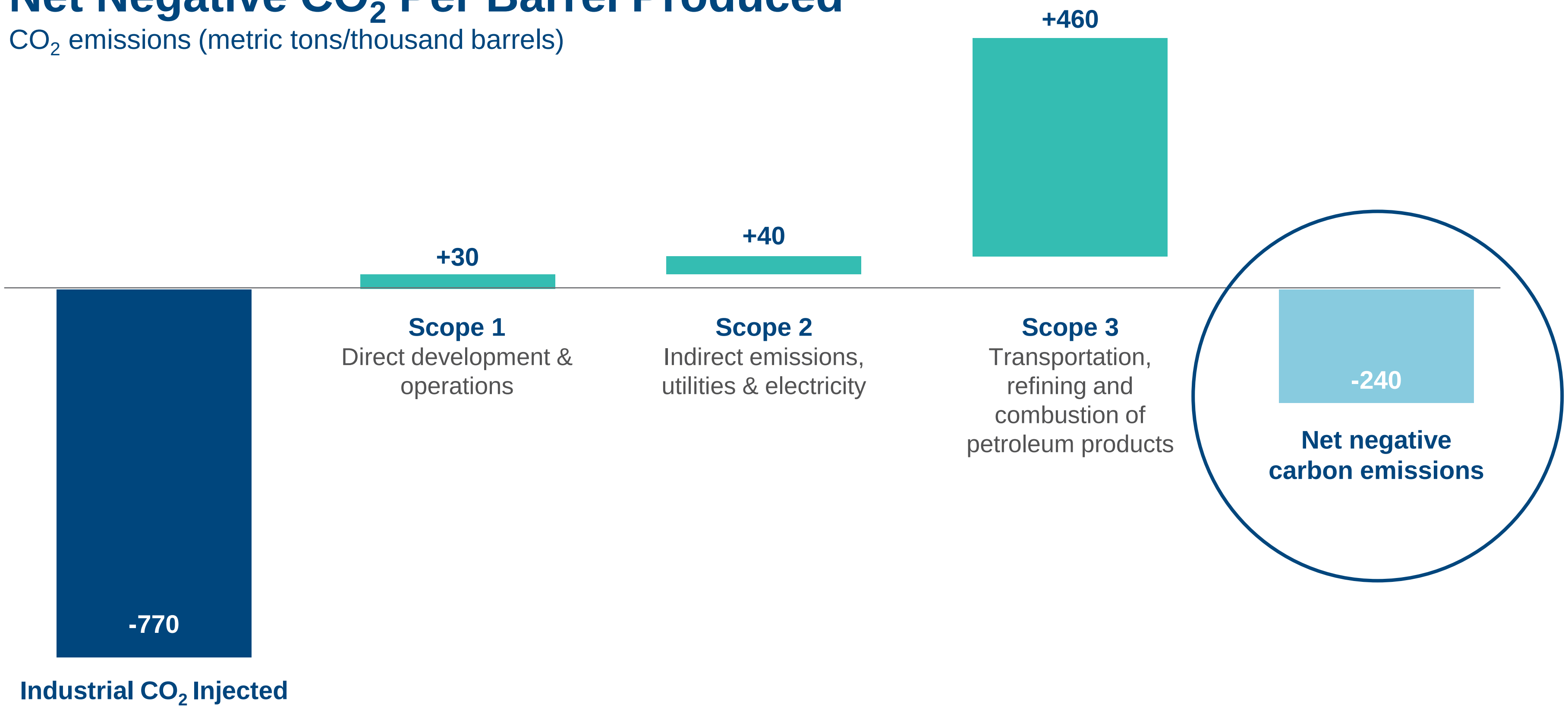
- Petroleum-based fuels remain a significant contributor to the global economy in all IEA scenarios
- Blue oil (negative CI score) and Electrofuels (net zero target) are direct drop-in fuels without modifications to infrastructure

Carbon-negative Blue oil is Scope 1, 2, 3[1] negative

Approximately 28% of DEN current production is Blue oil

Net Negative CO_2 Per Barrel Produced

CO_2 emissions (metric tons/thousand barrels)



(1) Scope 3 refers to Scope 3 Category 11 (Use of Sold Products)

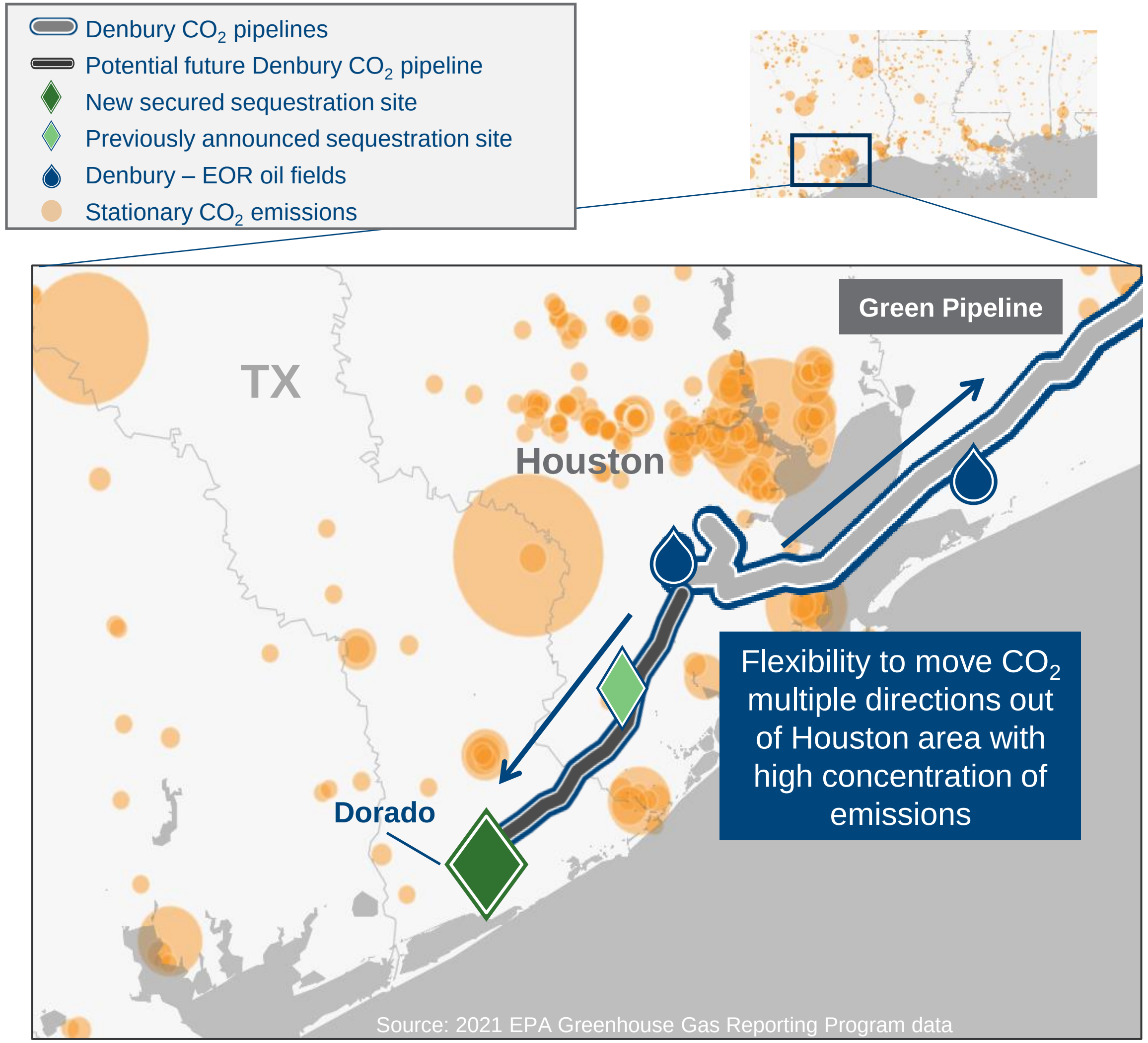
Strategic Gulf Coast Dedicated CO_2 Storage Acquisition

Dorado Sequestration Site in SE Texas

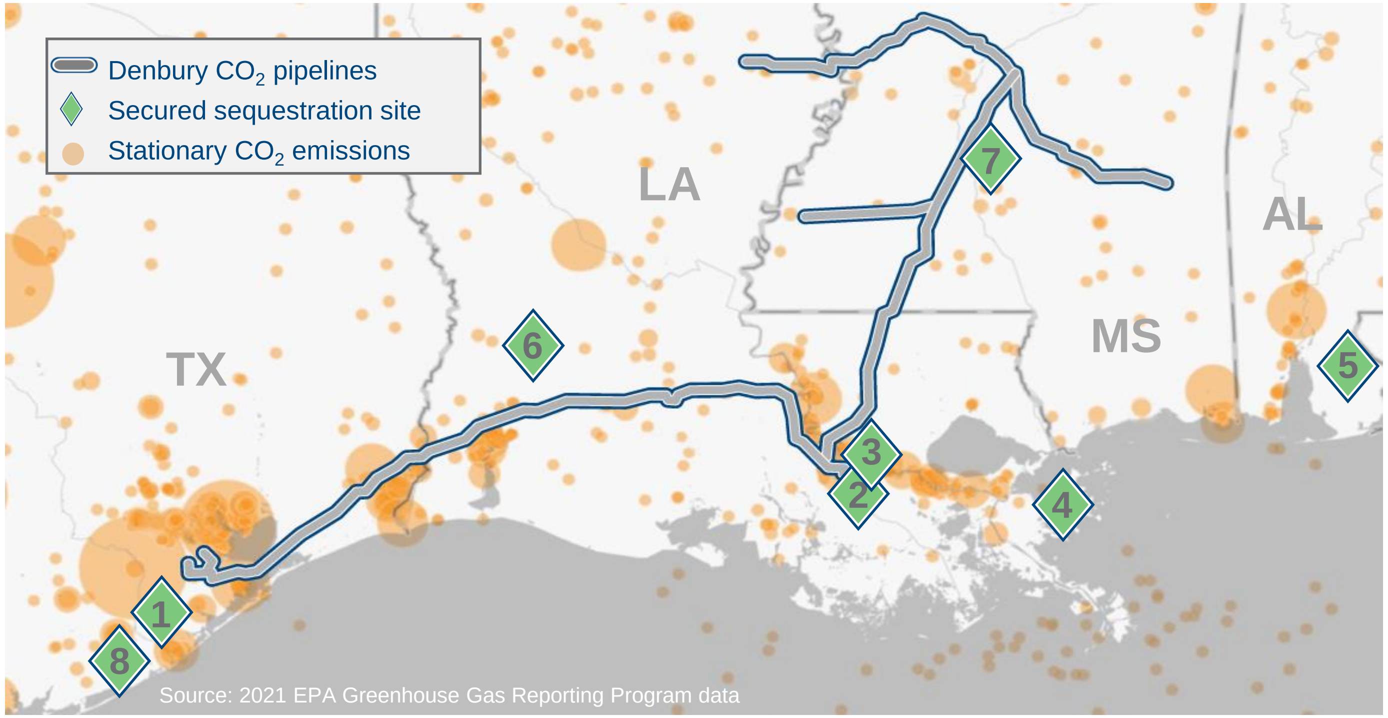
- 30,000-acre site in Matagorda County acquired in 2Q23
- Potential CO_2 storage capacity of >115 million metric tons
- Approx. 60 miles from DEN CO_2 pipeline infrastructure
- Plans to submit Class VI permits by end of 2023

Extensive Emissions in Houston Area; Potential to Expand Towards Corpus Christi

- 65 Mmtpa located 10-15 miles from Green Pipeline (power generation, petrochemical, refineries)
- Previously announced transportation agreement with HIF Global for a planned eFuels project in SE Texas with up to 2 Mmtpa of CO_2



Progressing >2.1 B Metric Tons of Gulf Coast CO_2 Storage



Submitted Initial Class VI Permits on Orion (3 permits – Nov. 2022) and Leo (6 permits – Apr. 2023)

- Plan to submit additional Class VI permits on at least two additional sites in 2023

Drilled First Stratigraphic Test Well in Orion site

- Additional 1-3 stratigraphic test wells planned across portfolio for 2023 (MS, LA, TX)

Plans to acquire additional sites in strategic locations near high emission areas

	(1) GCMP	(2) (3) Aries, Gemini	(4) Pegasus	(5) Orion	(6) Draco	(7) Leo	(8) Dorado
Potential storage capacity (million metric tons)	400	300	500	300	250	275	115
Distance to DEN pipeline (miles)	25	5,10	95	90	25	0	60
Acreage	850	29,000	84,000	75,000	31,000	16,000	30,000

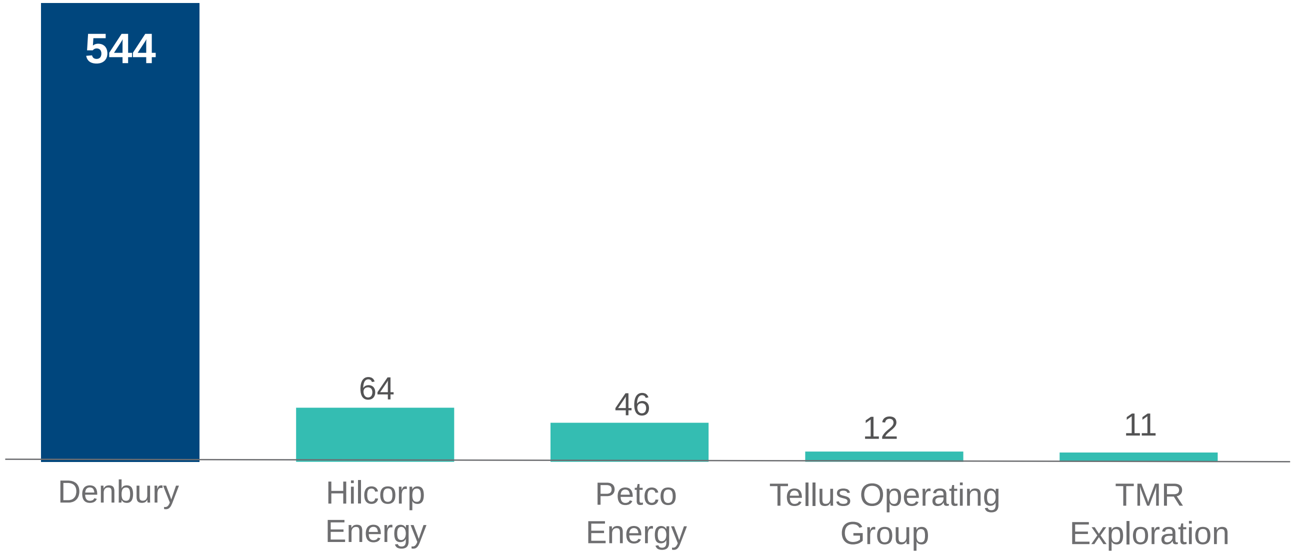
Well Positioned to Deliver on Class VI Development

DEN Clear Leader in Class II CO_2 Injection

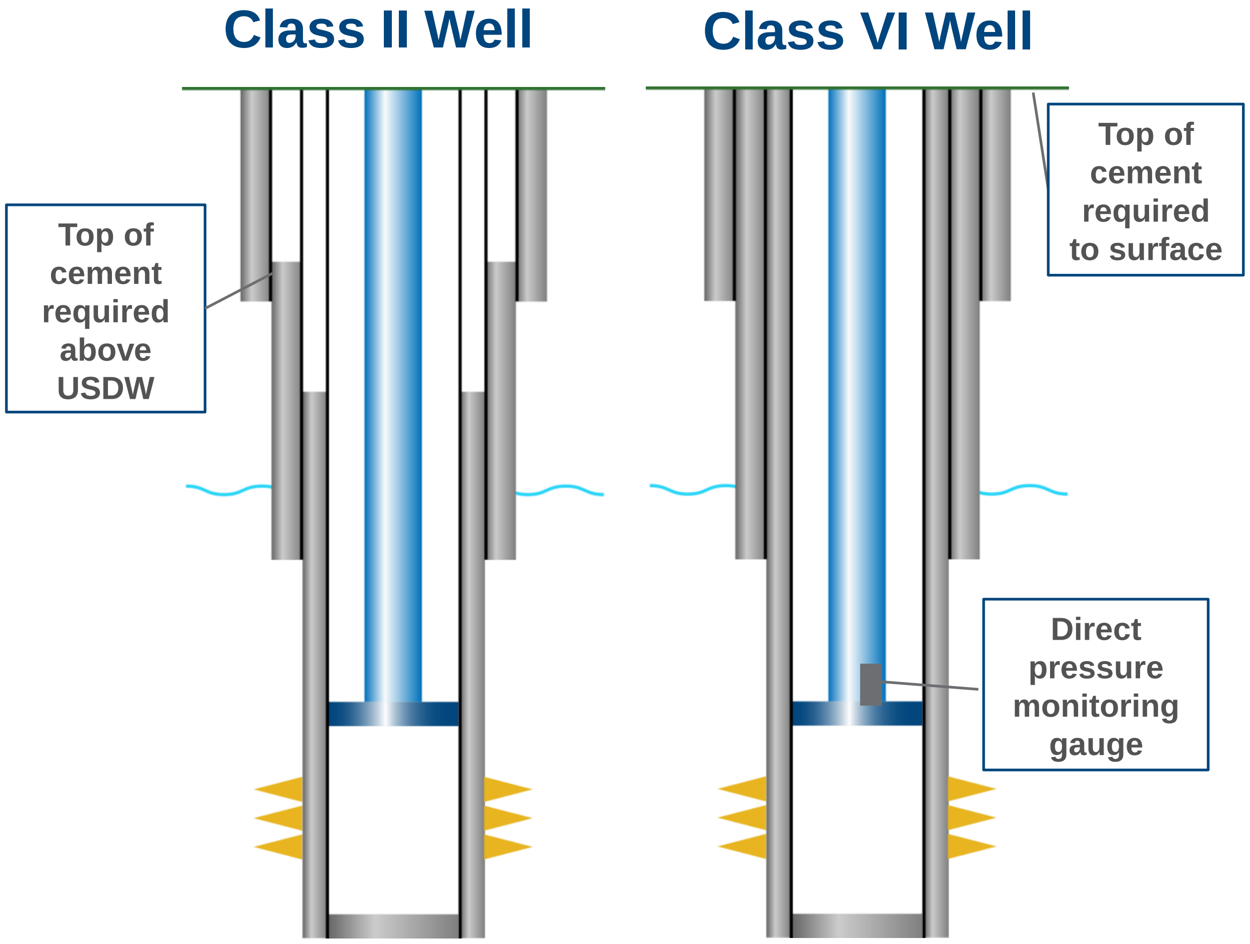
>750 CO_2 injection wells operating in the U.S.

DEN Class II Injection Wells in U.S. Gulf Coast

Count[1]

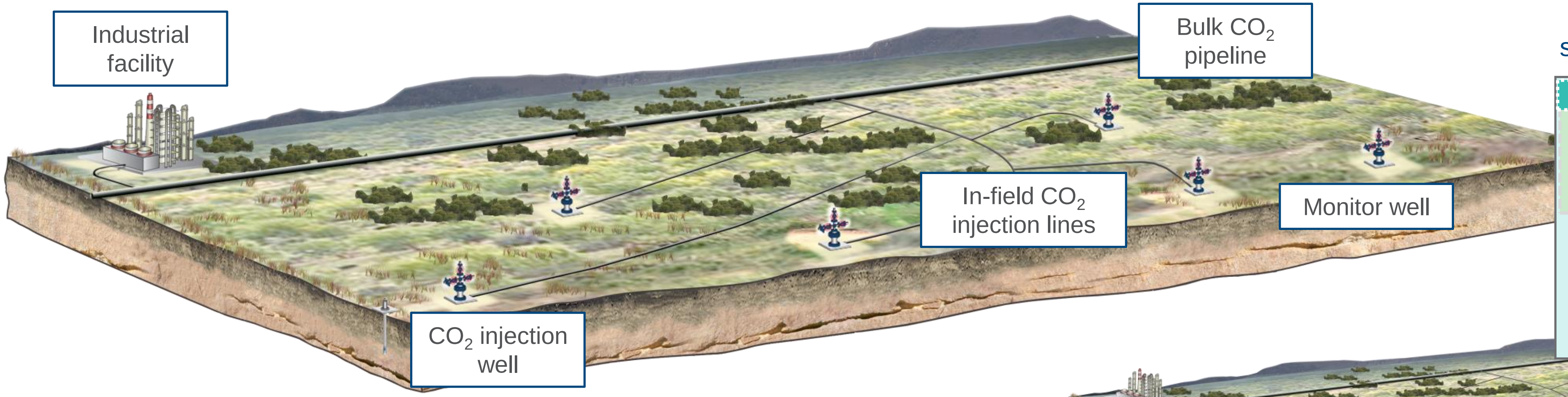


(1) Active Class II permits; filing data from RRC, MSOGB, LNDR

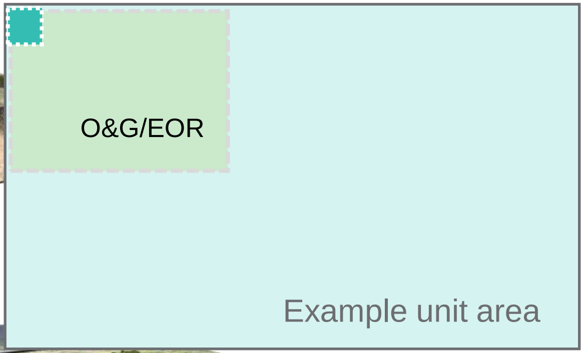


Highly similar construction
Class II vs. Class VI injection well

Example DEN CO_2 Sequestration Site

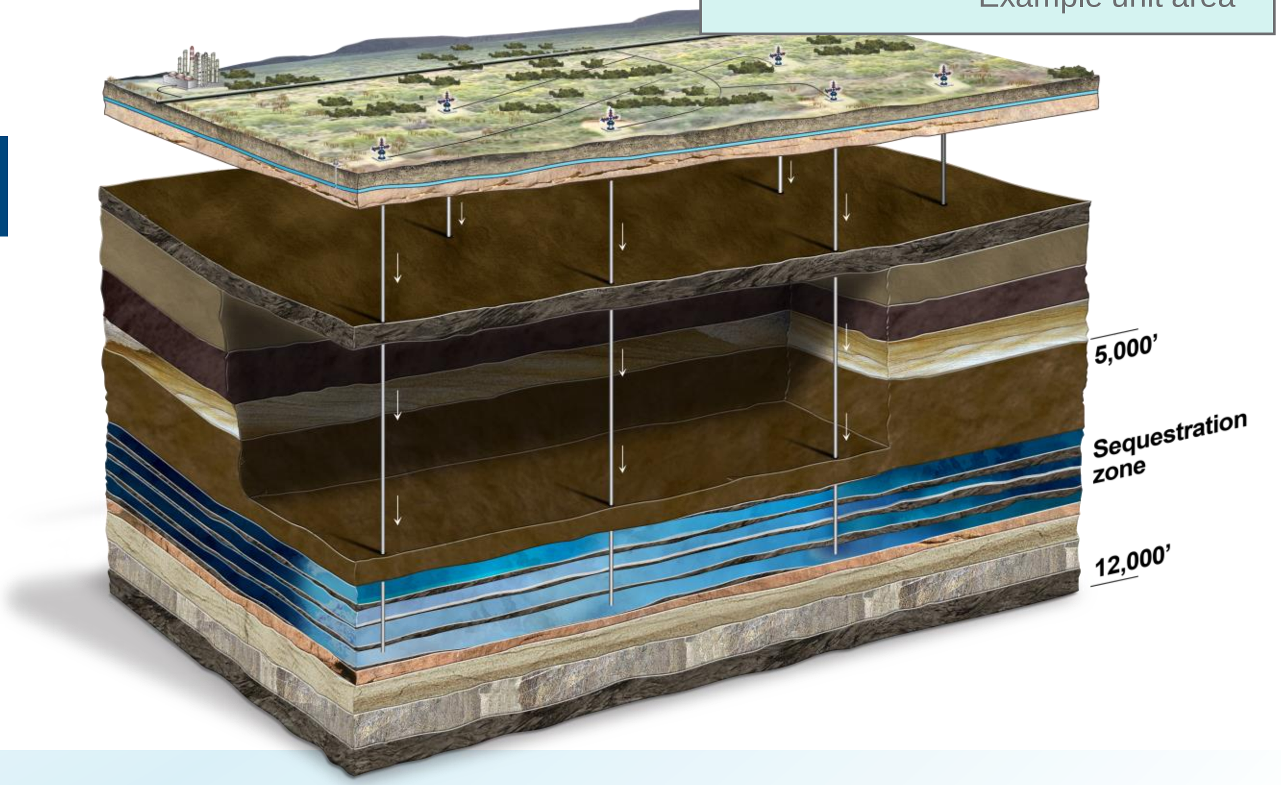


Sequestration results in 90% less surface impact than oil & gas operations



Generic 100 – 200 million metric ton site

- **20-year injection life @ 5 – 10 Mmtpa**
- **5 – 10 injection wells – avg. rate 0.5 – 1.5 Mmtpa per well**
- **Estimated capital $2 – 4 per tonne**
  - acquisition cost, seismic, wells (injection / monitoring), lateral pipeline, distribution network, abandonment
- **Anticipated operating expense $5 – 9 per tonne**
  - surveillance, utilities, repair & maintenance, labor, insurance, pore space payment

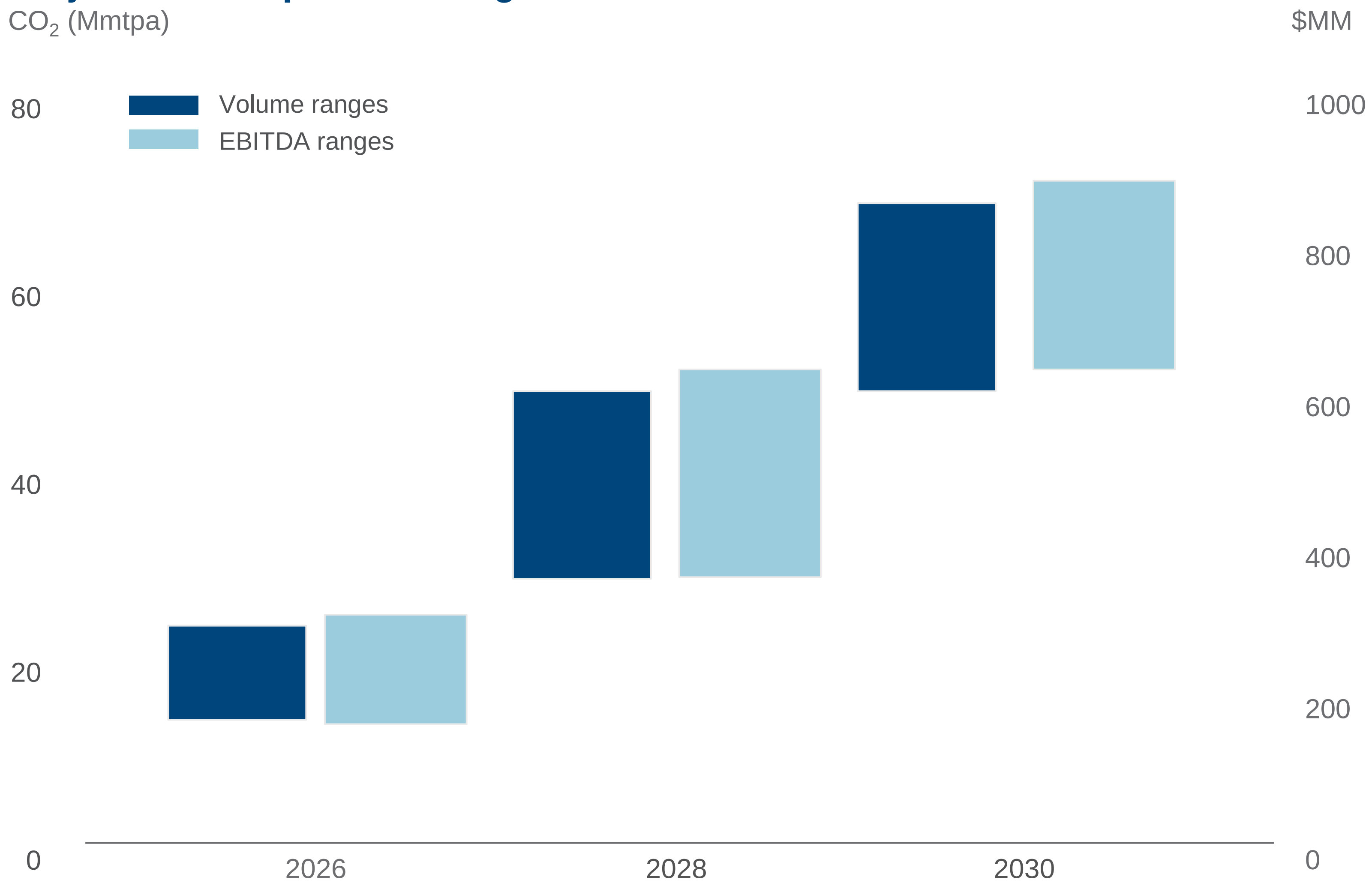


Note: Schematics are for illustrative purposes. All pipelines will be located underground

Projecting Substantial Growth in CCUS Volumes and EBITDA

- Initial volumes anticipated in 2025; **50 - 70 Mmtpa projected 2030 avg.** (~50/50 brownfield/greenfield split)
- Cumulative CCUS capital investments **estimated $1.6 - $2 B** from 2023 to 2030;
  - Avg. $200 - 250 MM per year
  - Highest investment period expected 2024 - 2025
  - Anticipated 30 - 35% spend on pipelines, 65 - 70% on sequestration sites
- Ability to organically fund CCUS capital expenditures through 2030 with oil @ $60 WTI
- CCUS self-funding **beginning 2026/2027**

Projected Transport & Storage Volumes **Estimated Annual EBITDA**(1)



(1) See "Statement Regarding Non-GAAP Financial Measures" on Slide 2

Denbury

Appendix

2023 Annual Guidance – as of May 3, 2023

	2023 Guidance	1Q Actuals	Forward Commentary
Oil & Gas development capital ($MM)	$350 - $370	$100	2Q anticipated consistent with 1Q
CCUS capital ($MM)	$140 - $160	$20	2Q expected higher than 1Q
Sales volumes (MBOE/d)	46 – 49	47.7	2Q planned consistent with 1Q - CCA anticipated higher; offsets Delhi and Tinsley
Realized oil differentials ($ / Bbl NYMEX)	($0.50) - ($1.50)	($1.28)	
Lease operating expense ($ / BOE)	$29.00 - $31.00	$30.12	2Q rate expected above 1Q based on seasonal labor/workovers and CCA EOR startup
Transportation and marketing expense ($ / BOE)	$1.15 - $1.35	$1.26	
G&A *(total)* ($MM)	$90 - $105	$23	2Q should increase based on employee hires for CCUS
Stock compensation ($MM)	$22 - $26	$5	
DD&A ($ / BOE)	$9.75 - $10.25	$9.80	Potentially above the high end of the range driven by 2Q CCA EOR startup
Diluted shares (million)	53 - 55	53.8	
Tax provision; % Current (of total taxes)	~25%; 5 - 10%	24%; 8.3%	

Commodity Hedge Position – as of May 3, 2023

NYMEX Oil Hedges

		2023		2024	
		1H	2H	1H	2H
Fixed-Price Swaps	**Volumes Hedged (Bbls/d)**	**9,500**	**18,000**	**5,000**	**1,000**
	Swap Price[1]	$76.65	$78.51	$75.34	$75.12
Collars	**Volumes Hedged (Bbls/d)**	**17,500**	**9,000**		
	Floor Price[1]	$69.71	$68.33		
	Ceiling Price[1]	$100.42	$100.69		
	Total Volumes Hedged	**27,000**	**27,000**	**5,000**	**1,000**

(1) Averages are volume weighted

Operating Cost Summary

LOE Cost Type	Correlation with Commodity Price	1Q23 ($MM)	1Q23 ($/BOE)	4Q22 ($MM)	4Q22 ($/BOE)	1Q22 ($MM)	1Q22 ($/BOE)
CO_2 Costs	High	$20	$4.76	$20	$4.74	$19	$4.53
Power & Fuel	High	37	8.57	38	8.91	37	8.76
Labor & Overhead	Low	35	8.19	36	8.37	33	7.73
Repairs & Maintenance	Moderate	8	1.88	6	1.36	6	1.34
Chemicals	Moderate	5	1.23	6	1.37	5	1.16
Workovers	High	15	3.55	13	2.89	13	3.08
Other	Low	9	1.94	7	1.67	5	1.30
Total LOE		$129	$30.12	$126	$29.31	$118	$27.90
Total LOE excluding CO_2 Costs		$109	$25.36	$106	$24.57	$99	$23.37
NYMEX Oil Price		**$76.15**		**$82.51**		**$94.54**	
HH Gas Price		**$2.79**		**$6.10**		**$4.55**	

NYMEX Oil Differential Summary

$ per barrel	1Q23	4Q22	3Q22	2Q22	1Q22	2022	2021	2020
Gulf Coast region	$(1.29)	$(0.40)	$0.66	$0.16	$(1.37)	$(0.19)	$(1.42)	$(1.14)
Rocky Mountain region	$(1.28)	0.56	1.02	0.01	(1.38)	(0.02)	(1.32)	(2.80)
Total Company NYMEX Oil Differential	$(1.28)	$0.03	$0.82	$0.09	$(1.37)	$(0.10)	$(1.38)	$(1.81)
Average realized oil price per barrel (excl. derivative settlements)	$74.87	$82.54	$92.77	$108.81	$93.17	$94.29	$66.52	$37.78
Average realized oil price per barrel (incl. derivative settlements)	$75.36	$73.13	$79.49	$77.63	$70.43	$75.19	$50.46	$43.40

Net Income / Adjusted Net Income Reconciliation

Reconciliation of Net Income (GAAP Measure) to Adjusted Net Income (Non-GAAP Measure)[1]

	1Q23	
In millions (except per share data)	**Amount**	**Per Diluted Share**
Net income (GAAP measure)	**$89**	**$1.66**
Noncash fair value gains on commodity derivatives	(21)	(0.39)
Estimated income taxes on above adjustments to net income and other discrete tax items[2]	5	0.09
Adjusted Net Income (non-GAAP measure)[1]	**$73**	**$1.36**
Weighted-average shares outstanding		
Basic	**51.5**	
Diluted	**53.8**	

(1) A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed May 3, 2023 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.
(2) Represents the estimated income tax impacts on pre-tax adjustments to net income.

Cash Flows from Operations / Free Cash Flow Reconciliation

Reconciliation of Cash Flows from Operations (GAAP Measure) to Adjusted Cash Flows from Operations (Non-GAAP Measure) and Free Cash Flow (Non-GAAP Measure) (1)

In millions	1Q23
Cash flows from operations (GAAP measure)	**$89**
Net change in assets and liabilities relating to operations	51
Adjusted cash flows from operations (non-GAAP measure)(1)	**$140**
Oil & gas development capital expenditures	(100)
CCUS storage sites and related capital expenditures	(20)
Capitalized interest	(2)
Free cash flow (non-GAAP measure)(1)	**$18**

NOTE: Free Cash Flow calculation is prior to use of cash for Asset Retirement ($9 MM 1Q) and CCUS equity investments ($7 MM 1Q)

(1) A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed May 3, 2023 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.