A Pivotal Moment

for Enhanced Oil Recovery & CCUS

UH Energy
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ABOUT

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INTRODUCTION

The Trump administration's "America First" energy policy, designed to reshape energy supply through increased production of fossil fuels and the expansion of nuclear energy, offers new opportunities as regulations are rewritten to spur production. Enhanced oil recovery (EOR), utilizing CO_2 captured from industrial sources, can play a crucial role in achieving these goals.

Understanding the nuances of those opportunities, however, including the potential to help meet new production demands by combining Carbon Capture, Utilization, and Storage (CCUS) with EOR operations, requires navigating a complex set of challenges involving geology and reservoir engineering, technology, business, and a patchwork of state and federal policy. The expansion of midstream infrastructure will also play a pivotal role in the success of these efforts.

One key to this future growth comes via the new federal tax bill, which solidified federal tax credits for CCUS, both when used for permanent storage and for boosting oil production through enhanced oil recovery. The 45Q tax credit for simply storing captured CO_2 has been retained at $85/ton, while the new credit for use in EOR is now also $85/ton, up from $60/ton under previous rules.[1]

This refers to CO_2 emissions captured from industrial sources and injected into geologic formations for long-term, safe, and permanent storage. Whether the goal is to store CO_2 or to use it to boost oil recovery, the tax credit remains the same, earned through the measurement, monitoring, verification, and accounting (MMVA) of the CO_2 in the formation in accordance with IRS standards.

CO_2 used in other applications, such as beverage carbonation or food processing, does not qualify for the credits. However, considering the administration's efforts to boost fossil fuel production, there has never been a better time to pursue the use of CO_2 for EOR.

Getting there, however, demands careful consideration. The key issues regarding technology and engineering, business investment, and regulatory uncertainty make the process far from straightforward. Our work at UH Energy can provide the analysis and best practices required to deliver value creation and investment clarity.

These technical challenges and uncertainties related to the use of CO_2-EOR must be resolved to inform investment strategies. Many oil fields already have existing EOR activities and using additional incremental CO_2 will yield predictable results in the near future. This is low-hanging fruit. Although regional limitations exist, with proper diligence, increasing the amount of CO_2 used in existing fields can quickly add value to the business, especially with the rise in tax credits. There's also an opportunity to consider broader prospects, including capture and transport, the MMVA technologies needed for accounting and tax credit benefits, and even new greenfield CO_2-EOR potentials.

The University of Houston prides itself on being the "Energy University®". While acknowledging the uncertainty, we are committed to helping U.S. industries determine how they can best utilize CCUS for EOR, spurred by the enhanced tax credits. We have redefined the mission of carbon management at the UH Center for Carbon Management in Energy beyond simply reducing emissions of carbon dioxide and methane to that of realizing and maximizing the value of these carbon-based molecules to produce a desired business result.

UH has partnered with the Southern States Energy Board to establish the CCUS Acceleration Coalition, a consortium of nearly 80 energy leaders dedicated to accelerating the commercial adoption of CCUS in the marketplace. All aspects of the value chain are represented, providing UH with a breadth of experience and expertise to help address the challenges and opportunities of expanding CCUS and CO_2-EOR.

This paper is designed to structure our research efforts to address immediate questions regarding the urgency to act now. What is required for EOR implementation, and what are the expectations of additional recoverable oil? In some cases, between one barrel and three barrels of oil per ton of injected CO_2 have been achieved, but results are specific to the fields and performance of the operations.

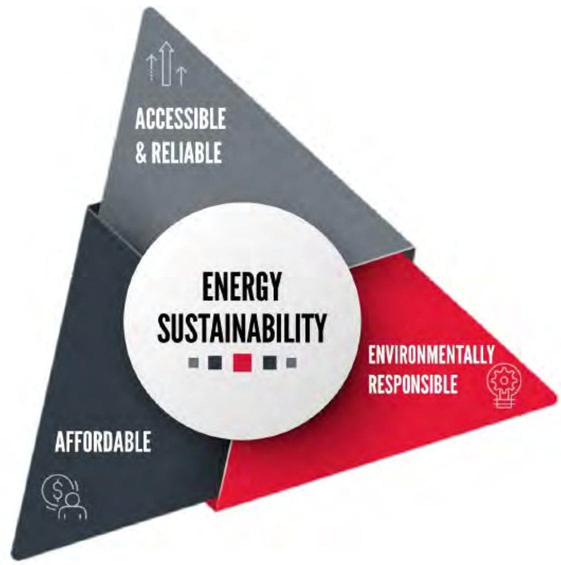


Figure 1. *The Energy Trilemma*

What policies and legal frameworks are in place, and what more could states do? What are the business risks, and how can they be mitigated? And what could EOR mean for jobs, growth, and long-term energy sustainability?

At the University of Houston, we define energy sustainability as requiring reliability, affordability, and lower carbon intensity, as shown in *Figure 1*.

The petroleum engineering department at UH has done extensive work in CO_2-EOR both domestically and internationally, and one of the nation's preeminent EOR experts has contributed to this paper. Experts from the Bauer College of Business have analyzed the risks and returns under various scenarios and will model investment profiles tailored to EOR. The University's chemical engineering team is addressing the most significant aspect of the CCUS value chain in terms of the cost of capture and preparing the emitted CO_2 into a fit-for-purpose fluid suitable for EOR. Critical markets will be identified in the case of pure storage projects in terms of scale and impact. This is another form of CO_2 utilization, as customers, markets, and the fungibility of a business case can be developed. Lastly, experts from the UH Law Center are addressing the legal and policy frameworks on a national and state-by-state level to incentivize CCUS and CO_2-EOR.

This white paper offers a comprehensive overview of the process of enhanced oil recovery (EOR) utilizing CO_2 captured from industrial sources drawing on data collected by researchers over several years.

Forthcoming white papers and reports from UH Energy and CCME will provide in-depth explorations of the technical and economic issues.

Key points to consider:

- Typically, one to three barrels of incremental oil per ton of injected CO_2 can be produced from existing brownfield developments with robust reservoir management and optimized flood patterns.[2] Results are not immediate in fields not already utilizing CO_2, and long-term viability must be considered based on the specific field and project.
- Greenfield developments often offer greater CO_2 storage per barrel produced due to larger uncontacted pore volumes.[3] They can also yield higher production gains. But it is critical to understand the risk and timeline, from investment to injection of CO_2 to actual yield of additional oil production. The risk profile is considerably higher with greenfield developments than for existing EOR field applications.
- Brownfield clusters in the Permian Basin, Gulf Coast, and Rockies benefit from existing CO_2 infrastructure, extensive reservoir data, and lower execution risk, making them near-term candidates for deployment.[4] Greenfield targets in the offshore Gulf, Alaskan North Slope, and specific mid-continent basins require new infrastructure, carry longer timelines, and face higher permitting and execution risks but offer greater CO_2 storage potential.[5–8]
- Carbon capture at scale from industrial sources, while demonstrated at various sites in the U.S. and globally, remains an issue that must go beyond the "first-of-its-kind" and prove reliability, free of fugitive and unintended emissions. Moreover, connecting these facilities with brownfield and greenfield CO_2-EOR sites through safe and cost-effective pipelines is an imperative. Addressing technical and non-technical risks in all aspects of the value chain, along with financial de-risking, is critical for the rapid advancement of CCUS and CO_2-EOR.
- Modeling from the Southern States Energy Board (SSEB) and the CCUS Acceleration Coalition organized by UH suggests that onshore CO_2-EOR projects typically need to yield at least 20 million to 25 million barrels of incremental economically recoverable oil to be viable when new CO_2 infrastructure is required, reflecting the necessary scale to justify pipeline and compression costs. Offshore projects will face even steeper infrastructural, financial, and operational challenges, but remain crucial for the required economically viable oil supply.
- Determining the economics of CO_2-EOR involves several factors. One key is the capture source, technology, location, and scale, estimated to be on average 70% of the total cost of CCUS via CO_2-EOR.[10,11]

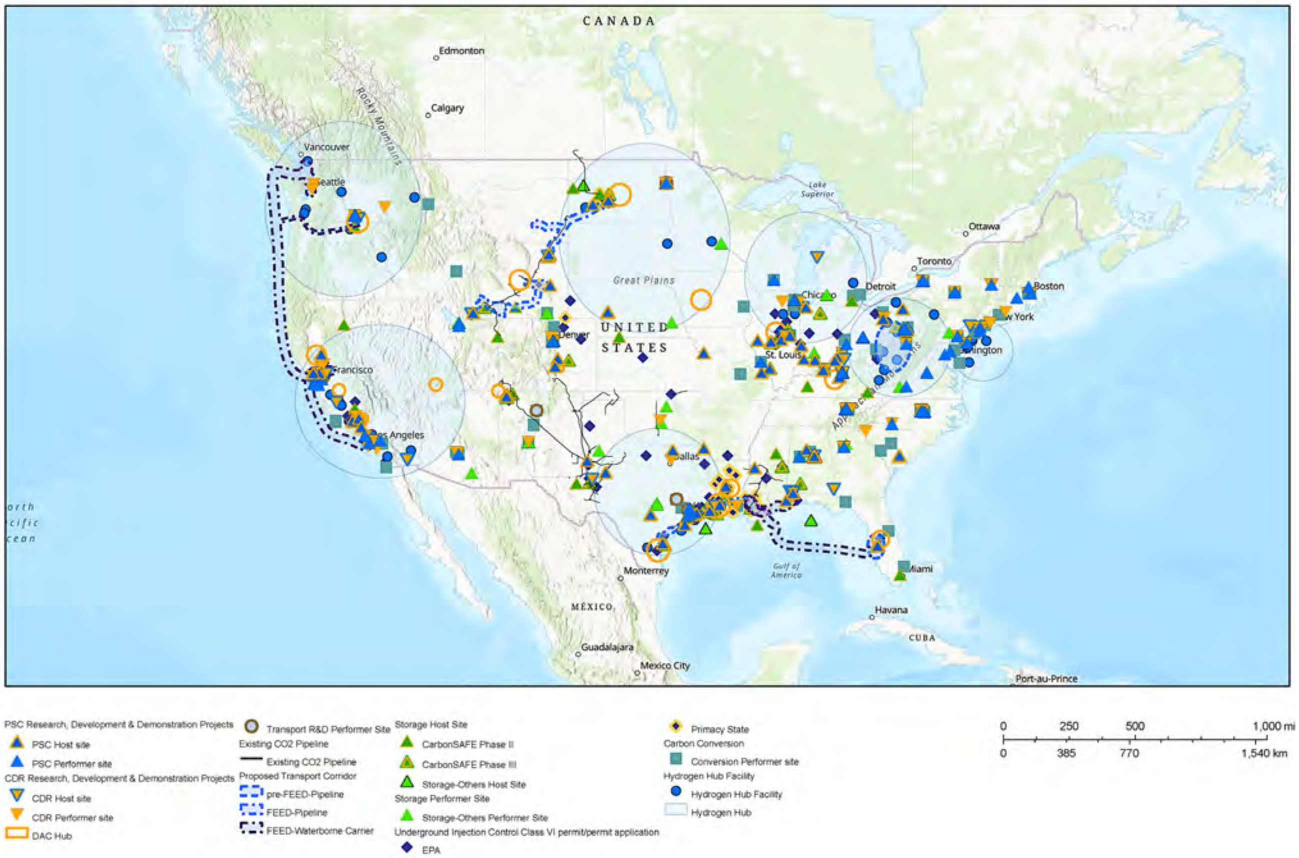


Figure 2. *Carbon management projects in the U.S. Here, PSC projects refer to Point Source Carbon Capture, and CDR projects refer to Carbon Dioxide Removal. A map of Large-Scale CO_2-EOR Field Projects in the U.S. is included in Appendix A. Source: U.S. DOE, National Energy Technology Laboratory.*[12,13]

In sum, there are two key markets for CO_2-EOR:

- Existing fields that have been produced with primary drilling and may or may not have been water-flooded for secondary recovery. Other fields where CO_2 previously has been used may have the capacity to take additional CO_2 from industrial sources.
- Greenfield reservoirs, those that are not yet producing oil, could be designed for CO_2 flooding from the outset of investment. Maximization of the pore space, the CO_2 being utilized, and the long-term productivity of the fields enable a full-scale evaluation of the value proposition.

Individual projects and associated demonstrations have been critical to understanding how to design, operate, and maintain CCUS projects. Clearly, scale and the ability to cluster opportunities in key geographies will affect the growth and commercial readiness of CO_2-EOR. Our perspective is that in today's environment of investment returns, there must be a sharp focus on where deployment can be accelerated and what it will take to make the necessary assessments.

LEVERAGING LEGACY LESSONS

Past and ongoing CO_2-EOR projects offer valuable benchmarks for estimating flood scope and CO_2 requirements. Mature brownfield operations, that is, those where production had previously commenced, such as the Means San Andres Unit (MSAU) and the Denver Unit in the Permian Basin, demonstrate that as many as three additional barrels of incremental oil per ton of injected CO_2 can be achieved with robust reservoir management and optimized flood patterns.[14,15] These results stem from conditions where CO_2 is injected into reservoirs with established injector–producer communication and residual oil saturation following decades of water-flooding. By contrast, greenfield developments, such as Lula Field (offshore Brazil) and Agbami Field (offshore Nigeria), may match or exceed the storage capacity of brownfields for associated gas and/or CO_2 injection.[16–18]

However, they require larger initial CO_2 or gas volumes for re-pressurization before incremental production is launched, as they begin without significant prior depletion or secondary recovery phases. The time from the start of CO_2 injection to observable oil response—often referred to as response time—also varies. In brownfield projects like MSAU and the Denver Unit, prior water-flooding had already established pressure support and fluid pathways, enabling an increase in the oil rate to be observed within six to twelve months. In the Scurry Area Canyon Reef Operating Committee (SACROC) area, also located in West Texas, CO_2 injection in the Four-Pattern area commenced in a well-controlled manner in mid-1981, and a definitive oil response occurred in early 1982, validating the range of our estimated response time (note that the field-wide injection started in 1972).[19]

In greenfield cases, such as Lula and Agbami, initial gas or CO_2 (or water) injection primarily serves to build reservoir pressure and establish displacement fronts, extending response periods to as long as three years, particularly for large, compartmentalized offshore reservoirs. Key factors influencing response time in both settings include pre-existing pressure maintenance, injector–producer connectivity, reservoir pressure relative to minimum miscibility pressure (MMP), pay-zone continuity, vertical sweep efficiency, and injection strategy (WAG [water-alternating-gas] vs. pure CO_2). Greenfield developments, although slower to respond, often offer greater CO_2 or gas storage per barrel produced due to larger uncontacted pore volumes.[20,21] The response time and the need for upstream CO_2 capture, midstream CO_2 transportation, and reservoir-head injection infrastructure can have significant impacts on the business and economic feasibility of the projects.

Past and current CO_2-EOR projects provide benchmarks for estimating flood scope and CO_2 requirements. Mature brownfield operations show that up to three additional barrels of incremental oil per ton of injected CO_2 can be achieved. On the other hand, greenfield developments may match or exceed the storage capacity of brownfields.

SCREENING FIELDS BY SIZE, SCOPE & INFRASTRUCTURE ACCESS

When screening candidate fields for CO_2-EOR, reservoir size and CO_2 supply logistics are key parameters to consider. The availability of CO_2, particularly whether a field is near an existing pipeline or requires a new dedicated pipeline, directly impacts the minimum size field that will be needed for commercial viability.[22] Simply put, projects must be larger to be commercially viable if the project requires significant infrastructure expansion to deliver CO_2 to the field.

(A) Fields close to an existing CO_2 pipeline

The presence of an extensive CO_2 pipeline network, approximately 5,300 miles in total (in the U.S.), significantly enhances the economic feasibility of CO_2-EOR projects in areas like the Permian Basin.[23,24] Fields such as the MSAU, located in Andrews County in West Texas, benefit from relatively short tie-ins to this network, with MSAU connected via roughly 30 miles of pipeline.[23] Such proximity allows operators to take advantage of shared infrastructure, established CO_2 supply contracts, and existing compression facilities.

(B) Fields requiring a new CO_2 pipeline

When a field lacks proximity to an existing CO_2 pipeline or source, as is often the case in offshore developments or remote onshore regions, the economics shift markedly. High upfront capital investment in new CO_2 transport infrastructure significantly raises the bar for new projects. Modeling from the National Energy Technology Laboratory suggests that CO_2-EOR projects in the U.S. can produce up to 4 million barrels of oil per day and 85% of this would be reliant on industrial CO_2.[23] Moreover, modeling from the Southern States Energy Board (SSEB) and the CCUS Acceleration Coalition organized by UH and SSEB suggests that onshore CO_2-EOR projects typically need to yield at least 20 million to 25 million barrels of incremental economically recoverable oil to be viable when new CO_2 infrastructure is required, reflecting the necessary scale to justify pipeline and compression costs. Offshore projects will face even steeper infrastructural, financial, and operational challenges. Technical assessments, such as the International Energy Agency greenhouse gas studies in the North Sea region, identify economic feasibility thresholds for CO_2-EOR only when fields exhibit huge recoverable volumes, often exceeding hundreds of millions of barrels, to offset the enormous infrastructure and logistical burden.[25]

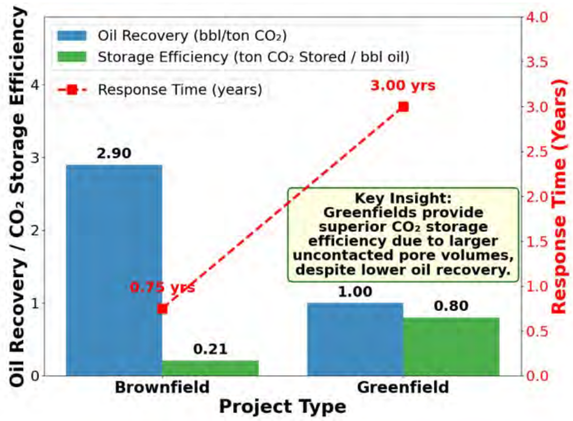
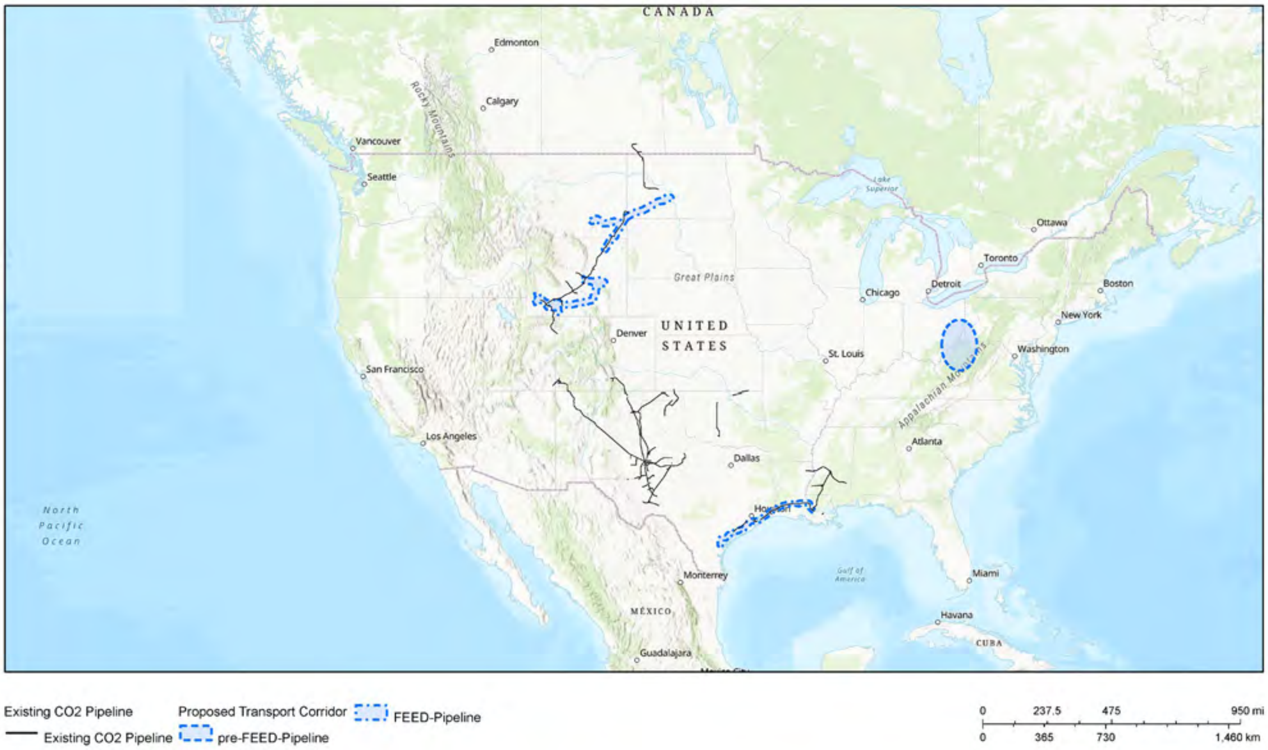


Figure 3. *Illustrative Strategic Trade-Offs in CO_2-EOR: Greenfield vs. Brownfield Development. Data sources: Based on data inputs from subject matter experts.*

> The availability of CO_2 determines the size of field required for the project to be commercially viable. If the project requires significant infrastructure expansion to deliver CO_2 to the field, projects must be larger.



Operator Name	Total Miles
Air Products & Chemicals Inc	12.90
Dakota Gasification Company	173.70
ExxonMobil Production Company, A Division of ExxonMobil Corporation	160.50
Bravo Pipeline Company	1042.30
Enmark Energy, Inc	9.60
XTO Energy Inc	24.90
Linde Gas North America, LLC	7.40
Trinity Pipeline GP LLC	179.80
Kinder Morgan CO2 CO. LLC	1298.50
Denbury Onshore, LLC	465.30
Apache Corporation	41.10
TreeTop Midstream Services, LLC	0.30
Denbury Green Pipeline-Texas, LLC	131.50
Denbury Gulf Coast Pipelines, LLC	382.00
Greencore Pipeline Company LLC	235.10
Greenleaf CO2 Solutions, LLC	5.10

Operator Name	Total Miles
Amplify Energy Operating, LLC	19.80
Scount Energy Management LLC	129.50
Capturepoint LLC	256.90
Elk Operating Services LLC	27.70
Breitburn Energy CO2	176.60
Daylight Petroleum LLC	149.30
Everline Complaince, LLC	81.10
Denbury Greem Pipeline-Montana, LLC	113.70
Denbury Greem Pipeline-North Dakota, LLC	9.30
Gary Climate Solutions, LLC	14.30
Contango Resources	155.00
Atlas Operating LLC	10.80
BKV Midstream, LLC	1.30
Silver Mountain Energy, LLC	15.00
NRG Maintenance Services LLC	0.40
Block T Petroleum INC	14.10

Figure 4. *Existing pipelines and mileage (in the table) and proposed CO_2 transport corridors in the U.S. Sources: U.S. DOT Pipeline and Hazardous Materials Safety Administration and U.S. DOE, National Energy Technology Laboratory.*[12]

TECHNICAL READINESS: BROWNFIELD VS. GREENFIELD

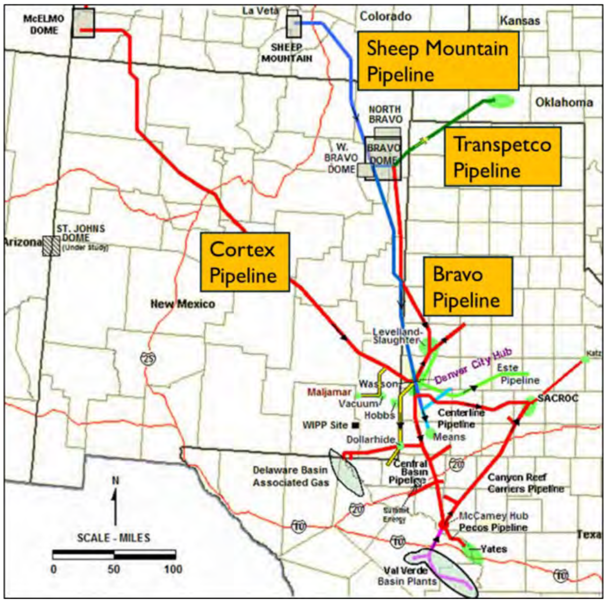


Figure 5. *Permian Basin CO_2 Pipeline Infrastructure. Source: U.S. DOE, National Energy Technology Laboratory (NETL).*[24]

The technical readiness of a CO_2-EOR project varies greatly between brownfield retrofits and greenfield developments, with notable differences in cost, permitting, and timeline. Brownfield projects, such as the MSAU and Denver Units, benefit from existing wells, surface facilities, and often water-flood infrastructure, allowing for the integration of CO_2-handling systems with minimal modifications. This simplifies permitting and shortens the timeline from investment to initial injection to actual oil yield realization. This can be aggressively accomplished in two or three years, but it can take as long as five years.[26] Capital costs generally are between $100 million and $500 million, depending on field size and infrastructure requirements.[27,28]

Conversely, greenfield developments require comprehensive field drilling, new gathering systems, CO_2 compression and distribution infrastructure, and often entirely new pipelines, in addition to more complex regulatory processes. These factors extend timelines to between five years and eight years and significantly increase capital costs, especially offshore,[29] such as in the Lula Field, where large-scale CO_2-EOR (or gas injection) projects can incur infrastructure expenses exceeding $1 billion.[30]

Brownfield clusters in the Permian Basin, Gulf Coast, and Rockies benefit from existing CO_2 infrastructure, extensive reservoir data, and lower execution risk, making them near-term candidates for deployment.[22] In contrast, greenfield targets in the offshore Gulf, Alaska North Slope, and specific Mid-Continent basins require new infrastructure, carry longer timelines, and face higher permitting and execution risks but offer greater CO_2 storage potential.[6] This classification enables prioritization of projects, balancing near-term oil recovery with long-term carbon storage objectives.

UH is developing advanced simulation tools and providing lab support for CO_2 screening and field validation frameworks. This includes:

- Building dynamic reservoir simulation models that incorporate real-time monitoring data and uncertainty quantification.
- Validating injection strategies through pilot-scale deployments and integration of geochemical tracers.
- Assessing CO_2 plume behavior via machine learning algorithms and geophysical imaging.
- Developing risk assessment matrices for prioritizing field selection based on techno-economic and environmental criteria.

Through collaborative research and partnership with industry stakeholders, UH can significantly reduce geological uncertainty and accelerate the deployment of economically viable and environmentally responsible CO_2-EOR projects across the U.S.

CAPTURE TECHNOLOGIES, CO_2 SPECIFICATIONS & INDUSTRIAL SOURCE MATCHING

Along with determining which fields are suitable for using CO_2 to boost oil recovery, it is necessary to consider the source of the CO_2, specifically what kinds of industrial CO_2 sources are technically and economically viable for enhanced oil recovery, and how the source type affects conditioning, transport, and miscibility.

This process begins by characterizing CO_2 streams from key emitters, including natural gas processing plants, refineries, steam methane reforming processes for hydrogen production, electric power producers, and others, in terms of pressure, impurities, and flow rate. From there, an assessment must be conducted for compatibility with EOR miscibility and pipeline specifications.

Beyond that, key factors in determining a suitable source include:

- Critical analysis of power production from existing coal-fired power plants equipped with carbon capture technologies.
- Critical analysis of natural gas combined cycle power production, both existing and new build, and of opportunities to optimize capture costs, including the cost of conditioning the CO_2 for fit-for-purpose transport.
- Recognition that conditioning requirements (e.g., dehydration, compression, contaminant removal) will affect cost, transportability, and reservoir performance.

Additionally, it is essential to compare CO_2-EOR with alternative utilization pathways to determine trade-offs in permanence, scalability, and technology readiness. Other potential pathways include mineralization, fuels, and concrete curing. The compelling economic case for CO_2-EOR will provide a distinct contrast in terms of value creation and scale.

As industries consider moving forward to capture the expanded 45Q tax credits, UH can offer support through a source-to-sink techno-economic model that matches real Gulf Coast emitters to viable EOR opportunities, factoring in capture feasibility and injection conditions.

Our focus will be natural gas combined cycle power generation with CCUS, existing coal-fired power plants, natural gas processing, and hydrogen production from natural gas via steam reforming or auto-thermal reforming.

Case		Capital Costs	Fixed O&M Costs	Variable O&M Costs	Purchased Power/Natural Gas	Greenfield COC	Retrofit COC
Ammonia		6.1	3.9	2.7	6.3	19.0	19.0
Ethylene Oxide		9.4	9.8	1.7	5.2	26.0	26.2
Ethanol		14.1	9.2	1.7	6.8	31.8	32.0
NGP		6.2	3.4	1.5	5.0	16.1	16.2
CTL		2.0	0.7	0.3	2.6	5.6	N/A
GTL		2.9	1.2	0.3	1.9	6.4	N/A
Refinery	90% Capture	22.8	15.6	5.3	16.2	59.9	61.7
Hydrogen	90% Capture	21.3	14.4	5.1	16.5	57.3	58.9
Cement	90% Capture	22.8	11.1	6.1	22.6	62.7	64.3
	90% Capture	21.8	10.6	5.9	22.6	60.8	62.4
Iron/Steel	90% Capture	28.0	9.5	5.7	22.6	N/A	65.9
	90% Capture	27.8	9.3	5.6	22.6	N/A	65.4
Pulp/Paper	90% Capture	27.4	13.5	7.5	0.0	48.3	75.9
	90% Capture	26.0	12.7	7.2	0.0	45.9	75.3
Note: All values expressed in December 2018 U.S. Dollars per tonne CO_2							

Table 1. *Cost of CO_2 Capture, in $ per ton, from Industrial Sources. Source: U.S. DOE, National Energy Technology Laboratory.*[31]

INVESTMENT PROFILE, PROJECT ECONOMICS & ENERGY MARKET INTERSECTIONS

Increased tax credits for CO_2-EOR will not, by themselves, be enough to make a project viable. Building a business case for a specific project involves considering factors such as CO_2 capture costs, the oil price, CO_2 productivity thresholds, and whether access to affordable CO_2 transportation is available.

A compelling and effective business case will include:

- Defining project lifecycle economics, including net present value (NPV), timelines, payback periods, and key sensitivity levers, such as oil price, CO_2 capture cost, transportation costs, and tax credits.
- Explaining how 45Q tax credits and oil production synergy can make CO_2-EOR projects cash-flow positive sooner than relying on carbon capture and storage alone.
- Exploring data centers as energy sinks and co-location opportunities for capture and EOR. For example, using waste heat or aligning with captured emissions from on-site generators.
- Examining how natural gas and electricity demand (especially in the Gulf Coast region) affect capture costs, infrastructure utilization, and investment scale.

Several factors contribute to determining the economics of CO_2-EOR. One key is the capture cost, which depends upon source, technology, location, and scale, and is estimated to be on average 70% of the total cost of CCUS via CO_2-EOR.

Other key considerations include:

- Oil field CO_2 economics (geology, location, size, oil price).
- Pipeline access connecting the source to the location of use.
- State incentives and regulatory policy.

Our work at UH in this area will be to validate the foundational hypothesis of our analysis, that CCUS via CO_2-EOR can be economically feasible. To do so, we need to identify the most cost-effective CO_2 sources, such as utility-scale natural gas and coal power generation, non-utility natural gas power generation, and oil and gas processing, including refineries, potential EOR locations, and link delivery mechanisms.

Beyond that, we consider a cluster of proximal additional CO_2 sources that can provide substantial volumes, offering multi-sourced reliability to deliver, thereby creating a hub of sources and delivery capacity to the sink where the CO_2 can be used at the EOR field(s).

Our work at UH will validate our foundational hypothesis:
using CO_2-EOR for CCUS can be commercially feasible.

FEDERAL–STATE ALIGNMENT, PERMITTING CERTAINTY, AND LONG-TERM LIABILITY

Despite federal incentives, deployment of CO_2-EOR varies widely across the oil-producing states, highlighting how policy can enable or hinder use of the technology. States are key players, and the rules can vary from state to state. That complicates operations for companies working across jurisdictions but also provides an opportunity for states to learn from one another.

CO_2-EOR projects have for decades been regulated as Class II wells, which cover the injection of fluids related to oil and gas production. U.S. states and territories are largely responsible for regulating Class II wells, with 43 states having been granted primacy to regulate this class within their jurisdictions.[32]

Class II wells can be authorized by a permit for new wells or by a rule for existing wells. In both cases, the process of permitting or authorizing by rule is far more streamlined than the process for Class VI wells, which govern wells designed to store CO_2 in geological sequestration.[33]

Only North Dakota, Wyoming, Louisiana, and West Virginia have primacy for Class VI wells.[34,35] Approval for Texas's application for primacy for Class VI wells appears imminent.

Thus, with the expectation of growth in CO_2-EOR following the increase in the available tax credit, new CO_2-EOR projects will require permits primarily at the state level.

Some states have gone further in inviting CO_2-EOR projects in recognition that the benefits go beyond increased production and can have significant environmental and corporate sustainability benefits. For example, in Texas, qualified CO_2-EOR projects are eligible for an additional 50% oil take rate reduction.[36] Wyoming is also enacting legislation to incentivize CO_2-EOR within its jurisdiction. There is a promising discussion among Wyoming legislators to add $5 to the CO_2-EOR, in addition to the federal 45Q.[37]

North Dakota, too, has expanded incentives for CO_2-EOR, offering tax exemptions for 10 years for incremental production in specific territories within the state. If more than 50% of the CO_2 injected comes from coal, the tax exemption can be extended to 20 years.[38,39]

This collection of state-level regulations and incentives also extends to the severance tax deduction. Almost all oil, gas, and coal-producing states—including Texas, New Mexico, Oklahoma, Wyoming, North Dakota, Colorado, Alaska, and Montana—have different severance tax deduction programs to support oil, gas, and coal production. Among these states, Wyoming and North Dakota have sales and use tax exemptions or property tax exemptions for carbon dioxide capture facilities.[40,41] This is an addition to the $85/ton federal credit under 45Q. In North Dakota, all materials used in the entire CO_2-EOR process, including compression, capture, transport, storage, and injection, are exempt from sales and use tax.[42,43]

Changes are underway at the federal level, too. An executive order issued in January 2025, "Unleashing American Energy," directed the Council on Environmental Quality to rescind its National Environmental Policy Act (NEPA) regulations as a step toward streamlining the permitting process.[44] NEPA review now will focus on technical and economic project analysis while limiting previous requirements for regulatory review based on climate and societal impacts.[44]

Additional hurdles to development include compliance with the measurement, monitoring, verification, and accounting (MMVA) plan, augmented with IRS-approved accounting procedures, which play a crucial role in gaining approval for the tax credits under 45Q. This creates the construct intended both to ensure accurate accounting and to reduce or eliminate CO_2 leakage, while also assuring the public of the safety and transparency of the process.

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APPENDIX

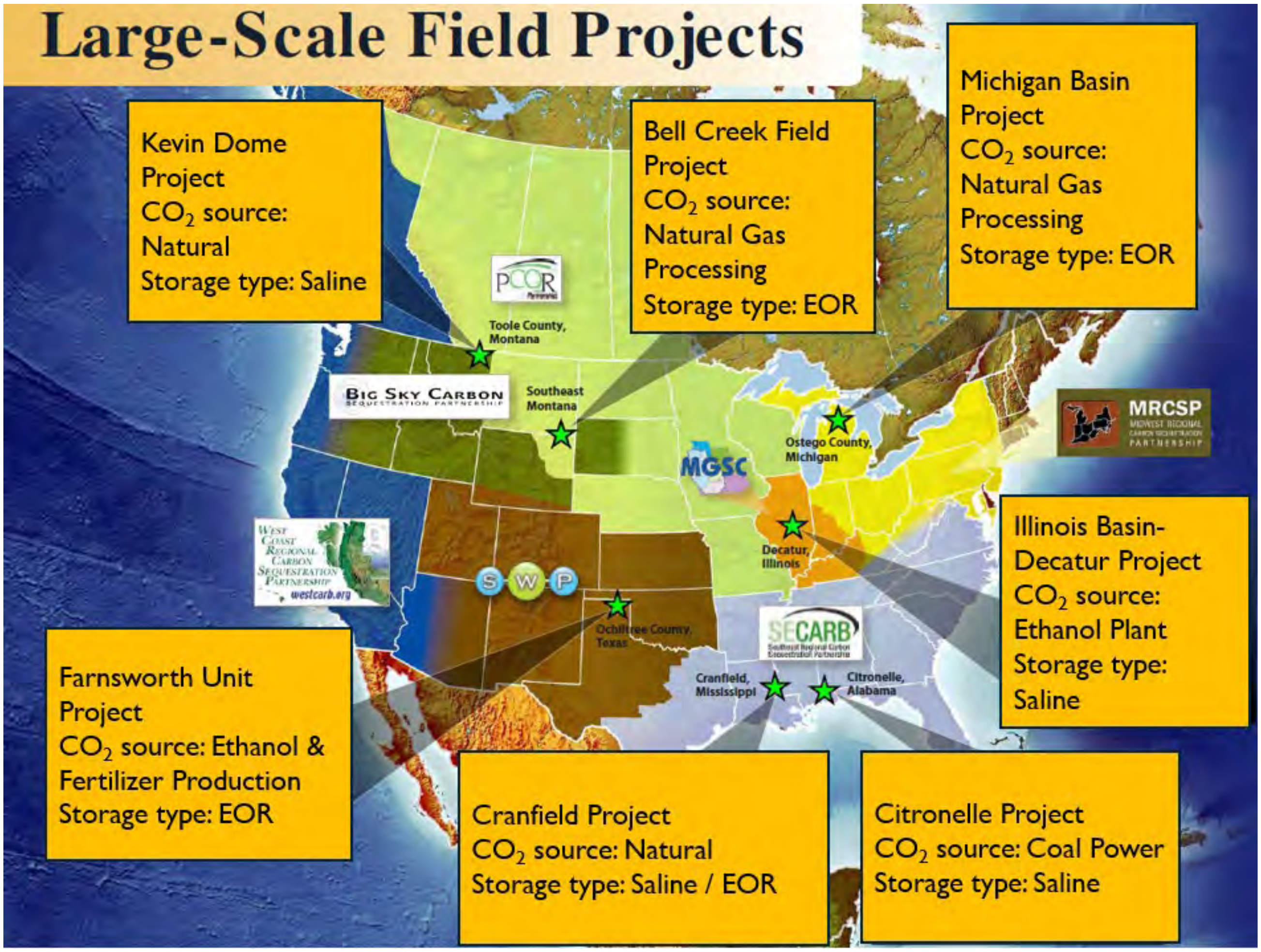

Figure A1. *Large-Scale CO_2-EOR Field Projects in the U.S. Source: U.S. Department of Energy, National Energy Technology Laboratory.*[13]

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UH Energy is an umbrella for efforts across the University of Houston to position the university as a strategic partner to the energy industry by producing trained workforce, strategic and technical leadership, research and development for needed innovations and new technologies.

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ABOUT CCME

The Center for Carbon Management in Energy (CCME), addresses the challenge of carbon emissions to support a sustainable energy future and healthier communities. Focused on emissions rather than fuels, CCME develops science-based, data-driven strategies to measure, reduce, and manage emissions across the energy value chain. Working with industry partners, the Center transforms research into real-world solutions for oil and gas, petrochemicals, electric power, and renewable energy sectors. Leveraging expertise in engineering, science, business, law, and policy, CCME is uniquely situated in Houston to drive innovative and practical pathways to a lower-carbon future.

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