Carbon Capture and Storage in Sustainable Aviation Fuel Supply Chains

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Project Team:

Anne H. Menefee, Assistant Professor of Energy and Mineral Engineering

Michael D. Helbing, Executive Director, Center for Energy Law and Policy

For correspondence about this White Paper, please contact Michael Helbing at mdh224@psu.edu.

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White paper prepared for ASCENT 001: Alternative Jet Fuel Supply Chain Analysis

Anne H. Menefee,[1] and Michael Helbing[2]

[1] Department of Energy and Mineral Engineering, Pennsylvania State University

[2] Center for Energy Law and Policy, Pennsylvania State University

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1. Introduction

Carbon capture and storage (CCS, where 'S' is interchangeably referred to as sequestration or storage) is considered an integral component of decarbonizing the energy and industrial sectors. In general, CCS involves capturing CO_2 (either from a point source emitter or, with recent technical advancements, from direct air capture units), transporting it via pipeline, compressing it to a supercritical phase, and injecting it deep underground. The latter stage is commonly referred to as geologic CO_2 storage (GCS), which requires access to a storage reservoir capable of receiving and retaining large volumes (megaton- to gigaton-scale) of CO_2 (P. Kelemen et al., 2019). Here, CO_2 is injected deep underground where reservoir temperatures and pressures are sufficiently high for CO_2 to exist in a supercritical phase, which is far denser than gas-phase CO_2 at the surface. As such, GCS in certain underground reservoirs is amenable to storing large volumes of CO_2 on par with anticipated emission reductions to reach national and global climate goals (Benson & Cole, 2008). The term CC(U)S (CO_2 capture, utilization, and storage) is also commonly used to reflect the many ways in which CO_2 can be utilized in industrial processes (e.g., pharmaceuticals, food and beverage industry, oil and gas industry, chemical processing) or material production (e.g., fertilizer production, concrete) (Supekar & Skerlos, 2014). This white paper will focus on sustainable aviation fuel (SAF)-CCS pathways where CO_2 capture is coupled with underground CO_2 utilization or storage, which is the 'end point' for CO_2 that is currently more compatible with handling megaton- to gigaton-scale quantities of captured CO_2 emissions.

The technology of CCS has existed since the 1970s, when it was invoked to capture CO_2 from industrial facilities for use in enhanced oil recovery (EOR) operations in the Permian Basin, Texas, USA. EOR remains the largest use of industrial CO_2 in the U.S., and is considered CO_2 utilization if the CO_2 is sourced from a human-derived source (National Energy Technology Laboratory (NETL), 2010). The extent to which EOR could be incorporated into CCUS portfolios and contribute tangible emission reductions is explored in Section 3.3. The first dedicated CCS project, where CO_2 was stored underground rather than used to produce more oil, dates back to the 1990s, when Statoil began a project to inject CO_2 associated with its offshore oil/gas production processes at the Sleipner site, offshore Norway (Gaus et al., n.d.). The Sleipner project, which was largely motivated by strict carbon taxes directed at oil and gas activity in the North Sea, has been a hallmark for demonstration of injection and monitoring techniques during CCUS (Benson & Cole, 2008). Since then, various pilot and commercial CCUS projects have been carried out to varying degrees of success, but CCUS has failed to see nationwide deployment. The lack of CCUS expansion, despite demonstrated feasibility of the technology, largely boils down to economics (including lack of infrastructure), gaps in current policy and regulation, and risk (both real and perceived).

While CCS cannot be used directly to reduce emissions from mobile sources, it can constitute a means of producing carbon-neutral or even carbon-negative fuel sources that could

lead to widespread decarbonization of the transportation sector. CCS could be particularly critical in reducing emissions associated with aviation, as aircraft would not benefit from emission reduction techniques like electrification using renewable-rich electric grids that can be applied to ground transportation fleets. CCS offers a mechanism for reducing the life-cycle emissions of liquid fuels necessary for operating aircraft. By sequestering a volume of CO_2 equal to or greater than the carbon emitted over the life cycle of the liquid fuel (including emissions from feedstock growth, fuel generation, and fuel transportation), integrating CCS into production chains can reduce upstream contributions to life cycle emissions, allowing for carbon-neutral or even carbon-negative fuel production.

The objective of this study is to document the current state-of-the-knowledge regarding CCUS, GCS, and potential opportunities for integration of CCS with SAF supply chains, along with opportunities and challenges in considering technical and regulatory aspects of the growing CCS industry. Section 2 introduces opportunities for capturing CO_2 process emissions in SAF production processes. It should be noted that studies on integrating CCS with SAFs typically assume generic cost or emission data for the CO_2 utilization or storage component and assume that all evaluated SAF production + CO_2 capture chains can be tied to this same boiler plate utilization or storage option. In reality, CO_2 utilization and storage options vary widely by region, and it may be inappropriate to assume that a given volume of captured CO_2 can be readily stored at a generic price point across the ranges of SAF production and CO_2 capture technologies considered. To this end, Section 3 categorizes the options for underground CO_2 storage, which is the CO_2 'sink' most capable of handling large quantities of captured CO_2, and provides an understanding of associated risks and permanence. Section 4 summarizes previous studies that have incorporated at least one CC(U)S option into life cycle or techno-economic analysis of specific SAF feedstock and production processes. Critical knowledge gaps for fully integrating CO_2 capture and storage into SAF production chains are then explored in Section 5, along with an assessment of current opportunities and challenges.

2. Primer on CO_2 capture in SAF production

The technical and economic viability of CO_2 capture in SAF production will depend on specific characteristics of the feedstock and production process. In general, CO_2 capture technologies fall into three categories: post-combustion capture, where feedstock-to-fuel conversion proceeds per usual and resulting CO_2 emissions are captured/separated from the flue gas; pre-combustion capture, where feedstock is first converted to syngas (gas rich in H_2 and CO_2) before combustion, which generates a more concentrated CO_2 stream; and oxyfuel combustion, which is essentially pre-combustion in the presence of pure oxygen instead of air. Capture units can invoke absorption (using solvents), adsorption (using solid sorbents), or membranes (with high CO_2 selectivity). Absorption, or solvent-based capture, is the most technologically mature and has been the most widely applied CO_2 capture technology at pilot and commercial scale. Of available solvents, monoethanolamine (MEA) is the most commonly used and is considered the most technologically mature. CO_2 capture using MEA can be employed either as a post-combustion

technology to capture CO_2 directly from flue gas, or in pre-combustion technologies to capture CO_2 produced in syngas.

SAFs produced from biomass have process CO_2 emissions that create a straightforward opportunity for post-combustion CO_2 capture. For instance, biofuels produced via thermochemical or fermentation processes release CO_2 during combustion or conversion, respectively, that could readily be captured instead of vented to the atmosphere (Ahlström et al., 2023). CO_2 capture (and subsequent storage, Section 3) from aviation fuels produced with biological feedstocks would be considered BECCS (bio-energy with carbon capture and storage), which has the potential to be net carbon-negative as cultivating the initial feedstock comes with an initial drawdown of atmospheric CO_2. Previous studies also explored the potential for pre-combustion technologies, such as conversion of forestry residue to jet fuel via the Fischer-Tropsch process and storage of CO_2 separated from the syngas via MEA absorption (Fernanda Rojas Michaga et al., 2022). While research explicitly considering BECCS for SAF production has been limited to date, previous life cycle and techno-economic studies that consider at least one CO_2 capture + utilization or storage path during SAF production are discussed in Section 4.

3. Geologic CO_2 storage (GCS) options and permanence

Geologic CO_2 storage (GCS) refers to injecting and permanently storing CO_2 underground, i.e. in geologic reservoirs. While most of our capacity to store CO_2 in quantities on par with appreciable emission reductions (megaton – to – gigaton scales) lies underground, not every region's geology is suitable for receiving and retaining such volumes of CO_2. In general, CO_2 can be stored in sedimentary basins, either within saline aquifers or depleted oil and gas reservoirs (Section 3.1), or in mafic reservoirs (igneous rock) capable of CO_2 mineralization (Section 3.2). Research has also explored the possibility of storing CO_2 in coal beds or depleted oil and gas shales, which have some advantages from the perspective of repurposing resources and infrastructure, but have much smaller storage capacities than large sedimentary or mafic reservoirs (and as such, are not detailed herein). Another geologic option is to inject CO_2 underground for enhanced oil recovery (EOR), where some of the injected CO_2 remains trapped in the formation (Section 3.3). Considerations specific to these different geologic CO_2 storage or utilization options are discussed in the following sections. An overview of GCS risk and permanence, as well as an introduction to the permitting process designed to minimize risk and ensure permanence, is provided in Section 3.4. Permit requirements are further detailed in Section 5.3 among other legal and regulatory aspects of GCS.

3.1. GCS in sedimentary basins: Saline aquifers and depleted oil and gas reservoirs

As a primer, sedimentary rocks are those that form at or near the earth's surface. The main types of sedimentary rocks that form underground reservoirs of interest are sandstones, which consist of relatively inert minerals like quartz, and carbonates, which consist primarily of carbonate minerals like limestone. Conventional oil and gas reservoirs are found in sedimentary rocks, and

the same properties that make them ideal oil/gas reservoirs make sedimentary formations prime candidates for GCS. Namely, sedimentary rocks have high porosity (fraction of pore space within the solid rock) and high permeability (ability to transmit fluids), which cater to oil/gas accumulation and production. In GCS, porosity is what creates storage capacity, and permeability is necessary to inject continuous volumes of CO_2.

Historically, GCS research and development has focused on sedimentary basins for several reasons. Sedimentary reservoirs are ubiquitous within continental regions, making them accessible to point sources of human-generated CO_2 emissions. As noted, sedimentary basins tend to have sufficient porosity and permeability to accommodate large volumes of CO_2 in a commercial CCS industry (Benson & Cole, 2008). There is also ample data and expertise available with respect to sedimentary reservoirs given decades of experience in the oil and gas industry, and they are widespread in the continental U.S. (Figure 1). More specifically, most GCS research has focused on storing CO_2 in saline aquifers within sedimentary basins (Celia et al., 2015). Saline aquifers are reservoirs that are naturally filled with high-salinity brines, with total dissolved solids (TDS) concentrations often much higher than those of seawater. Saline aquifers have no beneficial use to humans, such that GCS would not preclude or damage a potential future resource or use of the reservoir.

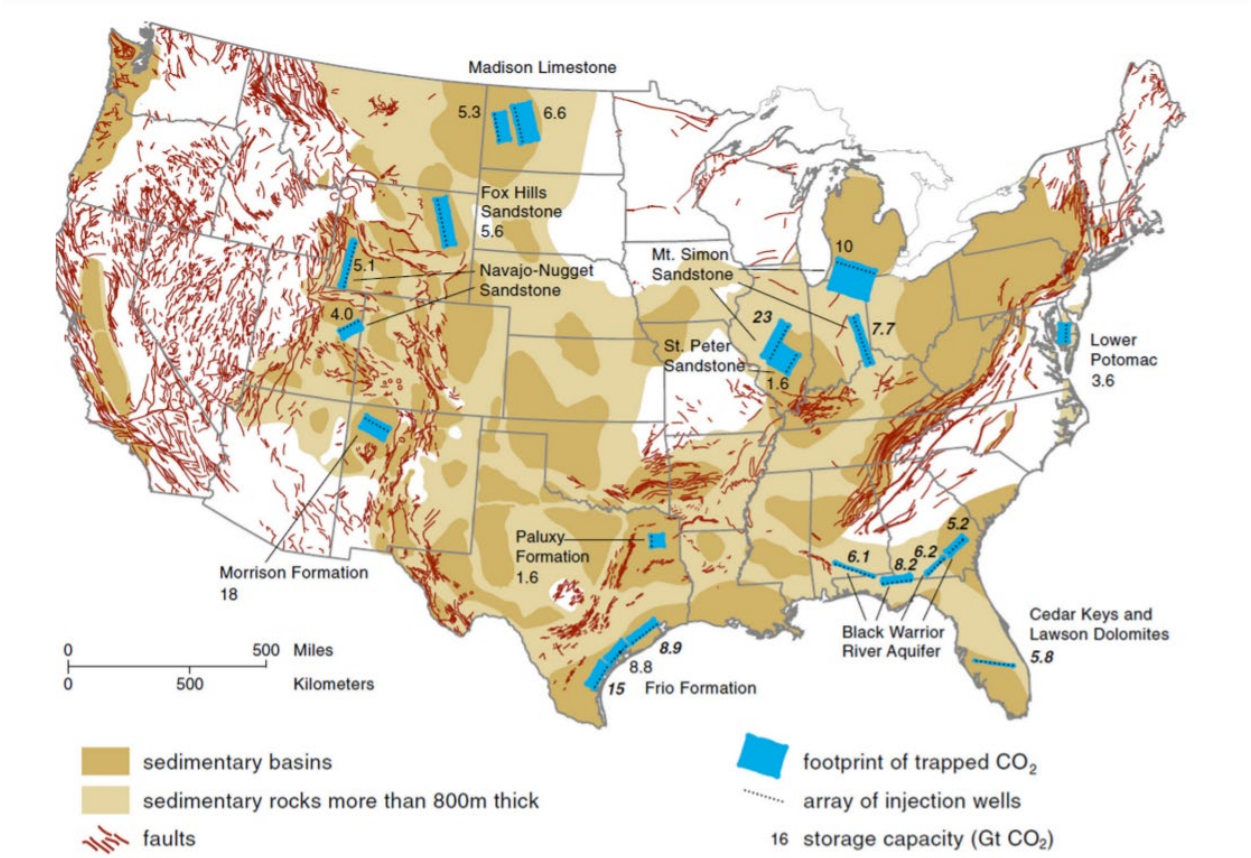


Figure 1. Map of sedimentary basins in the continental U.S., including CO_2 storage capacity estimates for 11 major basins that were deemed amenable to GCS. Figure from (Szulczewski et al., 2012).

Because most conventional oil and gas originate from sedimentary basins, there has also been interest in GCS in depleted oil/gas reservoirs within sedimentary basins. Reservoirs that are at or nearing end-of-life, and are thus pressure-depleted, could be converted to repositories for CO_2. If wells can be repurposed, this option could reduce capital expenditures (herein abbreviated Capex) associated with drilling and requisite equipment that would be needed to construct GCS wells in saline aquifers. However, there may be increased risks in depleted oil and gas fields associated with the prevalence of wells that could serve as potential CO_2 conduits if they have not been properly sealed (Mishra et al., 2014). Another consideration is that there are not abundant oil fields at or near the end of their productive life, and it would typically be more attractive to industry to utilize CO_2 for enhanced oil recovery (Section 3.3) rather than convert a reservoir with residual oil to a dedicated CO_2 storage repository.

CO_2 injected into saline aquifers or depleted oil/gas reservoirs is primarily stored through a mix of physical, capillary, and solubility trapping (Figure 2). Initially, most CO_2 will be physically trapped beneath an impermeable seal, or caprock. Over time, as the CO_2 plume moves and brine imbibes back into the pore space, some of the CO_2 is retained in pores and remains trapped ('capillary' or 'residual' trapping). CO_2 also dissolves into reservoir brine over time ('solubility' or 'dissolution' trapping). The storage security is generally considered to increase over time as more of the injected CO_2 moves from physical to capillary to solubility trapping (Hepple & Benson, 2005). In the case of basalt or mafic reservoirs, stored CO_2 can also progress to mineral trapping, where CO_2 is converted to solid carbonate minerals through a series of geochemical reactions. This mechanism is further discussed in Section 3.2. Note that sedimentary basins lack the types of silicate minerals that are needed to promote these mineral trapping reactions, and thus mineral trapping is not considered to be a significant factor during CO_2 storage in saline aquifers or depleted oil/gas reservoirs over relevant time frames.

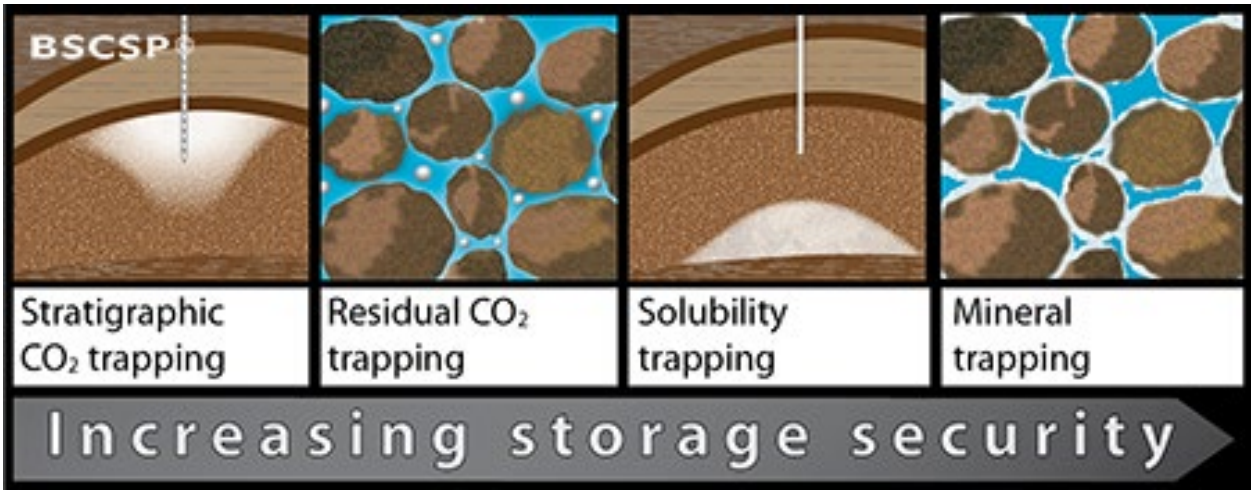


Figure 2. Visual of increasing CO_2 storage security associated with varying trapping mechanisms, which typically progress (left to right) from stratigraphic/structural trapping, to residual or capillary trapping, to solubility or dissolution trapping (i.e., CO_2 dissolves into resident brines) in sedimentary formations. In basalt or mafic reservoirs, a significant portion of the injected CO_2 can also be retained through mineral trapping (Section 3.2). *Figure source: Big Sky Carbon Sequestration Project, U.S. Department of Energy.*

In general, CO_2 injection, trapping, and migration involves multiphase flow regimes. An important consideration and subject of GCS research is that CO_2 dissolution into brine reduces the pH (i.e., increases the acidity) of the pore fluid, and interactions among CO_2, the existing formation fluid, and the surrounding rock (and/or wellbore cement) can lead to dissolution of existing minerals or precipitation of new minerals (Bacci et al., 2011). Thus, a component of Class VI permitting (Section 5.3) is demonstrating that CO_2 injection in the selected site will not lead to deleterious geochemical reactions that change the characteristics, and thus CO_2 migration and trapping behavior, of the reservoir itself or the specific wellbore materials used.

One paramount aspect to a GCS site is the presence and integrity of the caprock layer overlying the storage reservoir (Vialle et al., 2019). Considerations include identifying any fractures or channels, particularly channels that could be further opened by CO_2-induced dissolution of minerals within the rock layer, and identifying/remediating any improperly sealed wells in the area that could create leakage conduits through the caprock (Walsh et al., 2014). The latter is a major consideration for GCS in depleted oil and gas fields, which may have multitudes of wells that were drilled before modern regulations on proper plugging and abandonment. Verifying caprock and reservoir integrity, including remediation of any existing wells, is an important component of Class VI permit applications (Section 5.3) to initiate GCS at a given site.

3.2. GCS in basalts and mafic reservoirs

More recently, interest has grown in GCS in mafic or ultramafic reservoirs, such as basalts or peridotites, respectively (Clark et al., 2020; P. B. Kelemen et al., 2020). Whereas sedimentary reservoirs are mostly comprised of relatively inert minerals, mafic and ultramafic reservoirs contain an abundance of reactive silicate minerals like olivine and pyroxene that react with injected CO_2 and ultimately convert the CO_2 into solid carbonate minerals (Figure 3). Specifically, these minerals contain divalent cations (e.g., Mg^{2+}, Fe^{2+}, Ca^{2+}) that can be released from the rock due to CO_2-induced dissolution. In turn, mineral dissolution helps to buffer the pH of the formation fluid, eventually creating conditions where it becomes favorable for the released cations to combine with aqueous CO_2 to form solid carbonate minerals (e.g., $MgCO_3$, $FeCO_3$, $CaCO_3$). This process is referred to as mineral trapping, CO_2 mineralization, or mineral carbonation, and presents advantages with respect to storage security as CO_2 is solidified underground. However, reservoirs that are mineralogically capable of promoting mineralization are not as ubiquitous as sedimentary basins in continental regions, and there are lingering knowledge gaps surrounding the timing and rates of mineral carbonation reactions (P. Kelemen et al., 2019).

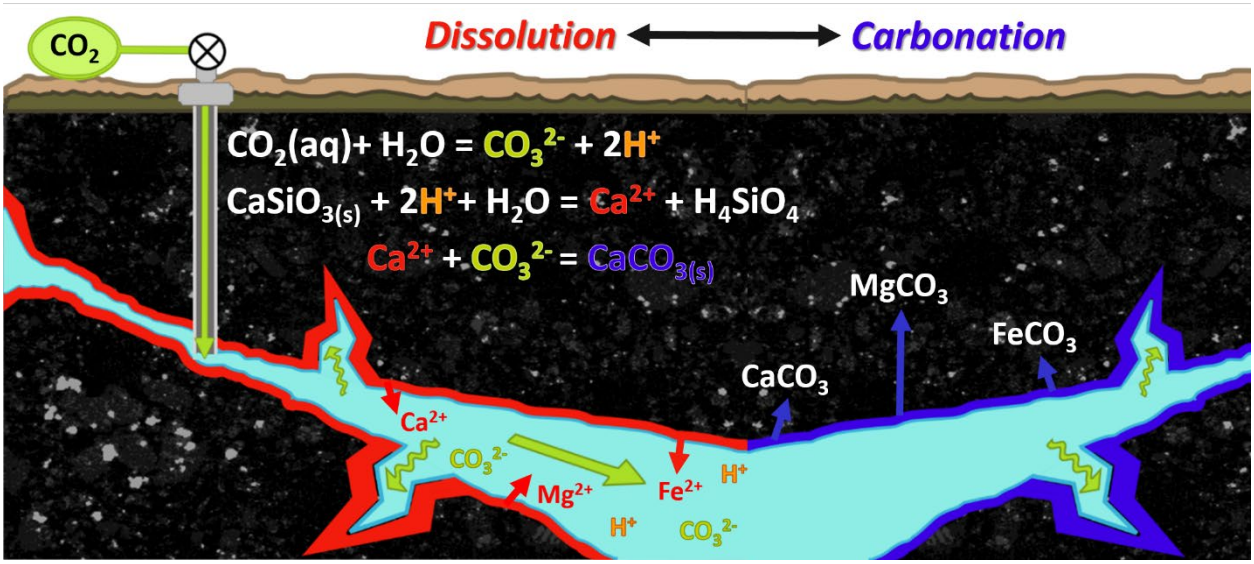


Figure 3. Illustration of CO_2 mineralization, or mineral trapping, in basalt for a simplified reaction sequence. Injected CO_2 dissolves into formation brine (or is pre-dissolved prior to injection), and then dissolves silicate minerals in basalt formations (here, CaSiO3(s)) to release divalent metal cations (Ca^{2+}, Mg^{2+}) into solution (red, lefthand side). As the pH increases, it becomes favorable for carbonate minerals ($CaCO_3$, $MgCO_3$) to precipitate (blue, righthand side).

Two successful pilot projects of CO_2 mineralization in basalt have been conducted to date: the CarbFix project in Iceland, and the Wallula project in Washington State, USA. Both were largely successful in demonstrating that mineral storage occurs much quicker than anticipated based on extrapolations of bench-scale data, albeit both initial pilot projects injected small amounts of CO_2. The original CarbFix test injected 175 tonnes of CO_2 into a basalt reservoir in Hellisheiði, Iceland in 2012, followed by injection of gas mixtures containing CO_2 and H_2S (Gunnarsson et al., 2018). One unique aspect of the CarbFix project was that the CO_2 was pre-dissolved in water, such that it was already in an aqueous phase (Aradóttir et al., 2011). This can improve mineral carbonation by reducing or eliminating the time it takes for CO_2 to dissolve into resident brines, but also reduces the amount of CO_2 that can be injected and stored per unit of pore space. Through the use of tracers and isotope analysis, researchers reported that >95% of the injected CO_2 was mineralized within two years post-injection (Matter et al., 2016). The project has continued to grow following success of the first pilot, and continues to inject CO_2 alongside H_2S captured from the Hellisheiði power plant (Snæbjörnsdóttir et al., 2020). CarbFix has also partnered with Climeworks, a Swiss company specializing in direct air capture (DAC), to pair their technologies for CO_2 storage in basalt with CO_2 capture from DAC units (Gutknecht et al., 2018).

In 2013, around the same time as the initial CarbFix pilot, the Wallula project injected ~1,000 tonnes of pure phase, supercritical CO_2 (rather than pre-dissolved) into Columbia River flood basalt at Wallula, Washington (state) in the U.S. (McGrail et al., 2014). The initial injection was followed by years of monitoring, including geophysical surveys, extraction of core samples, isotope analysis, and downhole fluid sampling, which has confirmed that the injected CO_2 has

been effectively contained in the formation (i.e., no leakage) (Snæbjörnsdóttir et al., 2020). Evaluation of extracted core samples revealed carbonate nodules which, through isotopic correlation, had formed due to interactions between the basalt reservoir and injected CO_2 (McGrail et al., 2017). More recently, numerical analysis of pre- and post-injection hydrologic tests performed in the reservoir determined that ~60% of the injected CO_2 had mineralized within 2 years (White et al., 2020). This result indicates that substantial mineral carbonation may be possible over similarly short time scales, whether CO_2 is injected as a pure phase or pre-dissolved. Pure-phase CO_2 injection may reduce upfront costs as well as storage efficiency.

GCS in reservoirs capable of mineral trapping is the subject of ongoing research efforts, primarily to understand conditions and time scales under which requisite reactions occur and the impacts of solid mineral precipitation on reservoir porosity and permeability, which govern overall CO_2 storage and mineral trapping capacities (Adeoye et al., 2017; Callow et al., 2018; Luhmann et al., 2017; Menefee & Ellis, 2021). Currently, there is no differentiation in policies or tax credits between CO_2 stored in basalt/mafic reservoirs (with at least a fraction of the CO_2 retained through mineral trapping) and CO_2 stored in saline aquifers/sedimentary basins (where the majority of CO_2 is retained via structural, residual/capillary, or solubility trapping). However, recent work lays groundwork for incorporating the risk that is intrinsic to different CO_2 trapping mechanisms in policies and incentives related to GCS, such as placing 'premiums' on CO_2 that is mineralized underground (Menefee & Schwartz, 2024).

3.3. CO_2-enhanced oil recovery

Enhanced oil recovery (EOR) encompasses a host of techniques that can be employed to extend the production life of oil reservoirs. Primary oil recovery, where oil production is maintained by pressure drive within the reservoir, typically only recovers on the order of one-third (or less) of the original oil in place. Secondary recovery can be employed to recover additional oil; the most common technique is waterflooding, where water is injected to re-pressurize the reservoir and force more oil out. Either following or in place of secondary recovery, enhanced oil recovery techniques can be applied. EOR involves chemical or thermal methods to enable extraction of oil that could not be recovered by conventional techniques. In particular, CO_2-enhanced oil recovery (CO_2-EOR) has been a common practice in the oil and gas industry since it began in the Permian basin (West Texas) in the 1970s. CO_2 is miscible with residual oil trapped in pores, facilitating incremental oil production in reservoirs where primary recovery (via natural pressure in the reservoir) is no longer feasible or economical (NETL, 2010). Injecting CO_2 also helps to restore reservoir pressure, which is depleted during primary oil production. In recent years, the US has injected on the order of 1.9 Bcf of CO_2 per day for EOR (around 36 million tons of CO_2 per year) (Advanced Resources International, 2024). In the context of GCS, a CO_2-EOR operation also provides a form of CO_2 storage, as 40-60% of the injected CO_2 is co-produced with oil and reinjected into the reservoir, while the rest of the CO_2 is retained in the reservoir. It is estimated that between 55 – 119 billion tonnes of CO_2 could be stored in oil fields through EOR operations (National Petroleum Council, 2019).

Historically, the majority of CO_2 used for EOR has come from deposits of naturally occurring CO_2, as it is cheaper than capturing and transporting CO_2 from point sources (Bielicki et al., 2014). However, oil recovered from CO_2-EOR operations that use such 'natural' or 'extracted' CO_2 has a higher emission intensity, as CO_2 that was already stored in natural deposits is extracted and used to produce more oil that generates more CO_2 upon use. For CO_2-EOR to be considered a CO_2 utilization pathway, the CO_2 source must be human-derived. While EOR is considered to be utilization, and not storage, approximately one-third to one-half of injected CO_2 is inherently stored in the reservoir (e.g., through capillary trapping, or dissolution into brines or hydrocarbons). CO_2 that is produced alongside oil is recycled and reinjected back into the reservoir, where more CO_2 becomes trapped during each cycle (Godec et al., 2013). From the perspective of CC(U)S, the main questions or concerns surrounding CO_2-EOR are: (1) does it actually generate emission reductions or credits, considering the emissions associated with EOR and in consuming the oil?, and (2) how much of the injected CO_2 is actually stored? These considerations are discussed below.

The extent to which CO_2-EOR affords emission reductions has been contentious. On one hand, if human-generated CO_2 is captured and used to produce oil that replaces conventional oil, there is an associated emission reduction (i.e., lower-carbon oil is produced). On the other hand, it can be argued that CO_2-EOR produces oil that would otherwise remain trapped, and that oil is then consumed to produce downstream CO_2 emissions, such that CO_2-EOR perpetuates fossil fuel consumption and associated emissions. The challenge of CO_2 accounting during EOR has been the subject of many previous life cycle analyses, where allocation can be difficult given uncertainties in what energy source(s) oil produced via CO_2-EOR may be displacing or in end uses for petroleum products. These studies have generated somewhat disparate results depending on assumptions related to CO_2 source and system boundaries, namely the extent to which downstream processes such as oil refining are incorporated and the end use considered for oil produced via CO_2-EOR. For instance, while a study incorporating upstream and downstream processes conclude that CO_2 storage during EOR does not offset associated emissions (Jaramillo et al., 2009), studies with earlier 'end points' have calculated net-negative emission scores (Khoo & Tan, 2006, Aycaguer et al., 2001).

In general, any benefits of CO_2-EOR hinge on the source of CO_2. Cooney et al. (Cooney et al., 2015) evaluated cradle-to-grave life cycle emissions for EOR using CO_2 sourced from both anthropogenic sources and natural domes. They found that process emissions were higher for CO_2-EOR than standard oil production, such that total life cycle emissions are higher for CO_2-EOR using natural domes than standard oil, as CO_2 storage credits do not apply. Conversely, using anthropogenic CO_2 from power plants resulted in lower life cycle emissions than standard oil, due to the negative emissions contributed by CO_2 storage. In other words, anthropogenic CO_2 sources result in lower life cycle emissions than conventional petroleum (alongside geologic storage of a portion of the injected CO_2), while CO_2-EOR using natural domes results in higher life cycle emissions (Cooney et al., 2015). Others have shown how life cycle benefits depend on both the

CO_2 source and assumptions about end use of produced energy, including what energy sources may be displaced by oil produced via CO_2-EOR. Azzolina et al. (Azzolina et al., 2016) also conducted a more detailed LCA of CO_2-EOR including upstream and downstream processes, but for CO_2 captured from coal-fired power plants. They calculate life cycle emissions of 438 $kgCO_2eq$/bbl (barrel) of oil produced via CO_2-EOR, a modest reduction compared to 500 $kgCO_2eq$/bbl in conventional oil under the same criteria (Azzolina et al., 2016). While the total emissions in CO_2-EOR are again higher than for conventional oil, the net emissions are lower when considering both the amount of anthropogenic CO_2 stored and displacement of conventional energy (Azzolina et al., 2016).

In addition to the question of emission reductions, a fundamental consideration for the use of CO_2-EOR in CC(U)S is how much of the injected CO_2 can be considered to be stored underground. As mentioned, the common assumption is that approximately one-third or more of the injected CO_2 is initially stored in the reservoir. The remainder is produced alongside oil, where it is separated at the surface and re-injected (i.e., recycled within the EOR operation); it is estimated that 95% or more of the CO_2 used in an EOR project is eventually stored in the reservoir (National Energy Technology Laboratory (NETL), 2010). A statistical analysis of 31 CO_2-EOR sites reported that a median average of 48.3% of injected CO_2 is retained in the reservoir, with the remainder recycled for use at other CO_2-EOR sites (Azzolina et al., 2015). Naturally, the amount of CO_2 that is actually trapped or stored at a given site will depend on specific reservoir properties, such as thickness, porosity (amount of available pore space), permeability (a reservoir's ability to transmit fluid), and characteristics of the existing hydrocarbons (Dai et al., 2016).

On the policy side, CO_2-EOR falls under the 'utilization' category of current 45Q tax credits available for CCUS. Under Section 45Q of the Internal Revenue Code, owners of equipment that captures and sequesters carbon dioxide from the atmosphere may be eligible to receive tax credits from the federal government (Angela C. Jones & Donald J. Marples, 2023). The value of those tax credits vary depending on a number of factors, and they are lower for EOR projects than for dedicated geologic storage (*See* Section 5.4) (Angela C. Jones & Donald J. Marples, 2023). Overall, EOR project economics can strongly depend on pipeline availability, as pipelines can be up to 40% of the capital expenditures in an EOR project and most existing pipelines were built when the price of oil was high enough to justify expanding CO_2-EOR operations (Tara K. Righetti, 2017). Most CCUS demonstration projects to date have relied upon EOR as the sink for captured CO_2; although EOR solicits a lower tax credit than dedicated storage, it is overall a more profitable endeavor, albeit the economics are highly contingent on the price of oil. Permitting requirements are also less stringent than those for dedicated GCS, which may reduce upfront costs and time in initiating a CC(U)S chain. Differences in permitting requirements between wells designated for EOR (Class II) and wells intended for GCS (Class VI) are included in Section 5.3.

In summary, CO_2-EOR as a means of CO_2 utilization/storage has been controversial, but the extent to which CO_2-EOR (using anthropogenic sources) can result in net emission reductions is strongly dependent on upstream emissions (associated with the specific CO_2 capture technology,

transport distances, etc.), downstream emissions in crude oil refining, and the amount of injected CO_2 that is ultimately stored in a given reservoir. CO_2-EOR can provide geologic storage of CO_2, but inherently results in fewer emission reductions than dedicated geologic CO_2 storage. However, an advantage of CO_2-EOR – and the reason it has been a go-to for CC(U)S projects – is that it is an established industry, and that it is more profitable than GCS, even with higher available incentives (tax credits) for GCS. The majority of existing CO_2 pipelines were also constructed to support EOR efforts and are located in centers of EOR activity, primarily along the Gulf coast, western Texas, Rocky Mountain region, and mid-continent (Kansas/Oklahoma) in the U.S. Thus, while utilizing CO_2 to produce more oil is not an ideal CC(U)S solution from a climate perspective, CO_2-EOR does have logistical and economical advantages as an outlet for captured CO_2.

3.4. GCS permanence

Much of the risk in CC(U)S, when using underground storage options, is associated with the GCS stage. Here, the main concern is ensuring injected CO_2 is permanently retained within a given storage reservoir, as well as avoiding induced seismicity. Regulators have responded to this concern through federal and state permitting processes. Although state requirements vary, , anyone pursuing GCS must first obtain a federal permit through Class VI of the Environmental Protection Agency's Underground Injection Control (UIC) program. Further details on the permitting process and pertinent considerations for employing GCS in SAF sectors are provided in Section 5.3). The UIC Class VI guidelines issue stringent requirements for demonstration of storage security (including adequate characterization of the underlying geology and robust simulations to understand where and how quickly the CO_2 plume will move), monitoring protocols to ensure CO_2 retention as well as avoid induced seismicity, and appropriate site closure measures before any project can begin. While the nature and magnitude of geologic risks will vary by location, such that it would be inaccurate to state an absolute rate of CO_2 retention or risk of leakage during GCS, these risks should be minimized through adherence to required practices under Class VI. In other words, obtaining a permit for GCS inherently requires operators to address potential risks during each stage of GCS: initial site characterization (Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance, 2013); monitoring, measurement, and verification (*Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance*, 2013); and plugging or post-injection site care (Underground Injection Control (UIC) Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance, 2016). Further considerations are discussed in 5.3, and as denoted by the preceding references, full documentation of requirements and regulations under Class VI for each stage of GCS are publicly available through the EPA.

As an additional note, entities such as the DOE and EPA have put forth that at least 99% retention of injected CO_2 over at least a 100 year time period is considered successful GCS (Hepple & Benson, 2005). Considering this metric and Class VI requirements, GCS sites that may exceed 1% leakage over 100 years would likely not be employed. In other words, near-100% retention is intrinsic to the selection of GSC sites and injection operations.

4. Prior research on integrating CCS with SAF and LCAF production

Several techno-economic analysis (TEA) or life cycle assessment (LCA) studies to date have incorporated at least one scenario that considers CC(U)S in alternative jet fuel (AJF), SAF, low-carbon aviation fuels (LCAF) production. Major takeaways from these studies with respect to CC(U)S capabilities in SAF supply chains are summarized below, along with their limitations; collective limitations of these studies are further discussed in Section 5.1.

4.1. Comparing SAF-CC(U)S potential with CO_2 storage vs. utilization in fuel synthesis

Ahlström et al. recently evaluated the carbon footprints and costs of CCS or CO_2 utilization (CCU) coupled with an array of SAF production pathways with leading conversion processes (2 gasification, 2 hydrotreatment, and 3 fermentation pathways), accounting for high altitude effects (i.e., proportionately higher warming effects associated with fuel combustion at high altitudes in aviation) (Ahlström et al., 2023). They reported that CCS would allow for 4 of the considered fuel production pathways to reach net negative emissions: synthetic jet kerosene from black liquor gasification and Fischer-Tropsch synthesis; synthetic jet kerosene from bark via circulating fluidized bed gasification and Fischer-Tropsch synthesis; synthetic jet kerosene from forest residues via hydropyrolysis; and synthetic jet kerosene from forest residues via fermentation to isobutanol and alcohol-to-jet synthesis. This does not mean that other processes that were not included in the research could not benefit from CCS. For the same processes, CO_2 capture and utilization (as well as the absence of CO_2 capture or utilization) resulted in net-positive CO_2 emission footprints. However, the specific utilization option considered in the study was in reactions with H_2 from electrolysis to generate additional biofuel; considering external (and less energy-intensive) utilization options could create more favorable carbon footprints. The remaining three production pathways considered (synthetic jet kerosene from tallow via hydrodeoxygenation; synthetic jet kerosene from wheat via fermentation to ethanol and alcohol-to-jet synthesis; and synthetic jet kerosene from sawdust via fermentation to ethanol and alcohol-to-jet synthesis) resulted in net-positive CO_2 emission footprints, even with integration of CCS, primarily because the majority of the feedstock waste is solid waste and lesser amounts of CO_2 are produced and 'available' for capture. Overall, the two gasification processes considered were the most promising candidates for reducing CO_2 footprints through CCS, as these had the highest emission reductions in 'negative' emissions associated with the feedstock, as well as CO_2 generated and subsequently captured during fuel conversion (Ahlström et al., 2023).

Becattini et al. (Becattini et al., 2021) also analyzed several CC(U)S options in jet fuel production, albeit from a techno-economic standpoint: conventional (fossil) jet fuel production coupled to CCS, and a CCU option where CO_2 is captured from a point source or direct air capture (DAC) unit and used as feedstock in synthetic jet fuel production. They found that CCS, either directly at jet fuel production facilities or through direct air capture facilities, was generally more economical in achieving net zero than CO_2 utilization, where synthetic jet fuels are produced using CO_2 as feedstock. Their results generally demonstrated that both CCS and the use of biogenic feedstocks (where the fuel's life cycle begins at a negative emission) are critical to maximizing

emission reductions (Becattini et al., 2021). Both of these prior studies indicate that the use of CO_2 as feedstock in synthetic fuel production is likely more expensive and less helpful in terms of emission reductions than capture and direct storage. However, we note that more conventional CO_2 utilization options, such as EOR (Section 3) or use in industry (pharmaceuticals, food/beverage, etc), may be on par with or better than direct storage, particularly with respect to economics.

4.2. SAF-CCS pathways using forest residue feedstock

Michaga et al. (Fernanda Rojas Michaga et al., 2022) carried out an LCA on jet fuel production via conversion of forest residues to syngas, with storage of associated CO_2, computed that 30.5% of the life cycle carbon ends up captured and stored, while 26.3% is contained in the final fuel product and 43.2% is wasted in process emissions. They assume 90% of the CO_2 contained in the syngas is separated and captured via MEA absorption. Incorporation of CO_2 capture from syngas resulted in a 2.57% reduction in energy efficiency, due to energy used in the capture unit, but lowers the life cycle GWP from 15.51 gCO_2eq/MJ (without capture) to -121.83 gCO_2eq/MJ (with capture). These results are most sensitive to the percentage of CO_2 captured in the syngas and feedstock transportation emissions, but nearly all Monte Carlo simulations resulted in a negative GWP when CO_2 capture is included. However, this study was based upon emission factors and policies in the U.K., and they assume uniform literature-derived values for transport and storage in each fuel production and CO_2 capture configuration considered (Fernanda Rojas Michaga et al., 2022). A more recent TEA study adopted Michaga et al.'s approach to calculate GWP reductions achievable by integrating CCS with SAF production. While the primary focus of this study was on evaluating the economics of two biomass-to-energy conversion processes with two types of feedstock at a regional level in the state of Virginia, their secondary CCS calculation indicated that CCS could render SAF production from woody waste carbon-negative, at a carbon intensity of -133.24 gCO_2eq/MJ (Davis et al., 2023). This would come at an added cost of \$14.50/tCO_2 captured and stored, which is offset by available credits for CCS, indicating SAF + CCS can both reduce CO_2 emission intensity and costs associated with SAF production (Davis et al., 2023).

Almena et al. (Almena et al., 2024) also performed a life cycle analysis of CCS integration into SAF production, specifically for Fisher-Tropsch synthetic paraffinic kerosene (FT-SPK) derived from forest residue. They assume that CO_2 is captured using solvent-based pre-combustion capture technology, resulting in 72% net capture of CO_2 during fuel conversion. They also consider compression to a pipeline that theoretically goes to geologic storage; CO_2 transport and storage components were taken from literature, but not explicitly considered. On an emissions balance, they calculated that approximately 44% of the biogenic carbon contained in the fuel feedstock (forest residue) is ultimately captured and stored by their assumed CCS process; 36% is retained in the resultant liquid fuel (thus, it will likely be released upon end use); 16% is directly emitted during the supply chain; and 4% ends up in solid waste products. In terms of life cycle carbon intensities, they found that FT-SPK integrated with CCS generates net-negative emissions of -20

gCO_2/MJ of neat fuel produced, but when considering that FT-SPK has a maximum certified mass blend of 50% with conventional jet fuel, the carbon intensity increases to 30.9 gCO_2eq/MJ. Thus, FT-SPK with CCS would still be carbon-positive after blending with jet A, but reduces emissions by 74% compared to conventional fossil fuel counterparts (Almena et al., 2024).

4.3. SAF-CCS pathways using forest residue feedstock

Batten et al. evaluated potential life cycle emission reductions achievable through integrating CCS with jet-A fuel blend production via biorefineries (i.e., using corn feedstock to generate 1,4-dimethylcyclooctane (DMCO)). They propose repurposing corn dry grind facilities to aviation fuel production to minimize the carbon intensity associated with this pathway, as well as to avoid domestic land use change (dLUC) and international land use change (iLUC) penalties. Like most studies related to SAF-CCS, they assume an average (literature-based) value for energy input to operate the CO_2 capture unit; however, they do not specify the end use for captured CO_2 or consideration toward any emissions incurred during utilization or storage. LCA results indicate that CCS can reduce life cycle GHG emissions from 36 gCO2eq/MJ DMCO to 4.9 gCO2eq/MJ. This 86% emission reduction could be significant at scale, as they estimate that converting and retrofitting existing first generation corn-ethanol biorefineries for DMCO production could meet ~12% of aviation fuel demand. Further emission reductions could be achieved through implementing best management practices in feedstock production and fuel switching to renewables in plant operations (Batten et al., 2023). However, techno-economic analyses would be necessary to ascertain whether this approach is economically viable.

4.4. Implementing CC(U)S vs. alternative emission reduction measures

Yoo et al. (Yoo et al., 2022) evaluated life cycle greenhouse gas emission reductions associated with different measures (a switch to renewable energy sources, CCS, and/or improving farming practices), specifically in Gevo's Net-Zero 1 plant that is slated to produce SAFs in South Dakota using corn as feedstock. Their boundaries encapsulated production and transport of corn feedstock; conversion to iso-butanol and jet fuel; and distribution and end use of the resultant SAF. The authors make several assumptions regarding the CCS component, namely a 97.5% capture efficiency, the use of grid electricity for the CCS unit, and literature values for energy/emissions associated with CO_2 capture and transport. Of the measures assessed, CCS resulted in the greatest reduction in CI score; if combined with the other measures (replacing the plant's electricity with renewables, and adopting sustainable farming practices that increase soil organic carbon storage), CCS can bring carbon intensities of corn-derived fuel at the plant to carbon-negative (Yoo et al., 2022).

4.5. Achieving cost-effective emission reductions via SAF-CCS

Overall, previous studies have concluded that utilization of residual forest waste is a prime candidate for SAF production coupled with CCS to achieve climate benefits (Ahlström et al., 2023). Another advantageous pathway for forest residue feedstock is production of jet fuel via forest residue-derived syngas, where CO_2 becomes more concentrated in the syngas and can be

captured; a previous LCA has shown this to be a means of producing negative-emission, albeit higher-cost, SAFs (Fernanda Rojas Michaga et al., 2022). Others have noted that CCS results in lower SAF production costs when accounting for revenue from available CCS credits (Davis et al., 2023). Of course, the ability of CCS to appreciably reduce emissions depends on the composition of the feedstock, which governs the extent to which CO_2 will be produced as a byproduct of fuel conversion, as well as the process emissions associated with the conversion process itself. However, particularly in considering current 50% blending limits on SAF that limit their ability to exclusively achieve net-zero emissions, research to date indicates integration of CCS can help reduce emissions toward carbon neutrality and may increase the longevity of SAF in increasingly constrained carbon economies (Watson et al., 2024). Further considerations for integrating CC(U)S measures with SAF production, including challenges unique to the CC(U)S supply chain that have not been incorporated into prior studies of SAF-CCS processes, are discussed in Section 5.

5. Opportunities and challenges for integration of CCS in SAF supply chains

5.1. Limitations of prior SAF-CCS research

When considering implications for fully integrated SAF-CCS supply chains, the main limitation of previous studies incorporating SAF-CCS (Section 4) is that they do not explicitly resolve the transport and storage components of the CCS chain, which can be an important component of CAPEX, OPEX, and emission balances and would likely lead to variations in reported results. Furthermore, consideration to the specifics of how and where CO_2 would be transported and stored is necessary because there are likely cases where a study's anticipated storage or utilization option for captured CO_2 is not technically or economically viable in that region. Such specifics will necessarily be case-by-case in a given region and market, but applying broad assumptions on geologic storage and associated costs may overestimate the potential for CCS.

From the reverse perspective of the CCS industry, integrating CO_2 capture with commodity products is beneficial in offsetting CAPEX associated with capture units, transport, and affiliated CCS infrastructure (Fernanda Rojas Michaga et al., 2022). Thus, integrating SAF production and CCS likely offers tangential benefits to the growth and sustainability of both industries. Future studies could consider SAF-CCS in the context of the broader CC(U)S industry and potential synergies with ongoing projects, as opposed to standalone analyses of how CC(U)S can improve the emission balance of specific SAF facilities or feedstock/processing techniques.

5.2. Pipeline considerations

For many commercial-scale GCS operations, it will be necessary to transport CO_2 from the location where it is captured to the site where it will be injected. Although CO_2 can be transported by truck or ship, the most efficient transportation method is typically via pipeline. However, the process for permitting and constructing CO_2 pipelines can be a laborious and expensive undertaking. As an initial matter, it is not clear in all cases which regulatory agency has primary

authority over pipeline siting and operation, and even where authority is clear, several agencies may be involved, complicating the process and adding to the regulatory burden. For example, although federal approval is required for siting a CO_2 pipeline across federal land, individual states generally have primary siting authority on non-federal land. As a result, a pipeline that crosses state boundaries will generally require permits from multiple states.

States have varying policies with respect to CO_2 pipeline siting, including factors like required setbacks, siting requirements, the role of local governments, and public participation (Tara K. Righetti, 2017). Most importantly, each state has its own criteria for the use of eminent domain, which is the authority to take private property for public use (Tara K. Righetti, 2017). The federal Constitution requires that in order for the government to assert eminent domain authority, it must demonstrate both public use of the property taken and just compensation to the original property owner (Tara K. Righetti, 2017). Different states have different interpretations of what "public uses" they consider appropriate for invoking eminent domain, and because CO_2 pipelines are relatively new uses, many states have not yet established whether, or under what circumstances, they may permit eminent domain authority to be used to take private property for purposes of siting a CO_2 pipeline (Tara K. Righetti, 2017).

Without the ability to use eminent domain, pipeline developers will need to rely exclusively on private negotiations with landowners to obtain property rights for pipeline siting. Considering that pipeline proposals have often been met with considerable public opposition (Paul W. Parfomak, 2023), relying on voluntary agreements to obtain property rights can add significant expense and risk to project development. Furthermore, even in areas where regulatory authority is clear, uncertainty remains. Although it is known that the federal Pipelines and Hazardous Materials Safety Administration (PHMSA) has authority to regulate CO_2 pipeline safety, those regulations are currently being reviewed, and PHMSA plans to propose revised regulations in November 2024 (U.S. Office of Management and Budget, 2024).

Pipeline construction is notoriously expensive, including indirect costs related to the regulatory considerations denoted above. As mentioned in Section 3, CO_2 pipelines exist in the U.S., but are limited to regions of historic oil and gas activity where they were constructed to support EOR activities, where they can account for up to 40% of the capital costs associated with EOR. Resultingly, most of these pipelines have been constructed at times when oil recovery was highly profitable, and many are connected to large natural deposits of CO_2 rather than point sources of anthropogenic emissions. Pipeline construction to support GCS will likely be a major CAPEX component of CC(U)S, particularly if development occurs piecemeal (e.g., individual facilities or storage operators constructing point-to-point lines for specific projects) rather than at regional scales. Invoking a cluster-hub model for CC(U)S, where 'clusters' of emission sources are connected to 'hubs' of utilization or storage sites, can help to spread costs among stakeholders and reduce upfront risks, but require coordinated planning. Furthermore, pipeline infrastructure should in most cases be 'oversized' to accommodate future growth of the CCS industry and integration of more emission sources, which can increase CAPEX and may place greater risk on early adopters.

Recent proposals to construct CO_2 pipeline infrastructure, including those by Summit Carbon Solutions and Navigator CO_2 Solutions, have encountered public opposition and regulatory obstacles, but the efforts continue (Kevin Baskins, 2024; Leah Douglas, 2023).

5.3. Class VI permitting process and considerations

Under federal law, wells used for geologic sequestration of carbon must obtain a permit under the Underground Injection Control (UIC) Program established under the Safe Drinking Water Act (U.S. Environmental Protection Agency, 2024a). Under the UIC program, wells are classified by the type of substance being injected underground, including wastes related to oil and gas production. In 2010, a separate class (Class VI) was added for geologic CO_2 storage; thus, permits for dedicated CO_2 injection are known as "Class VI" permits (U.S. Environmental Protection Agency, 2024a).

Currently, Class VI permit applications in most of the country are administered federally by the appropriate regional offices of the U.S. Environmental Protection Agency (EPA). Although there is a process, known as "primacy," that would permit individual states to administer the Class VI permit programs within their boundaries, only North Dakota, Wyoming, and Louisiana have obtained primacy for Class VI permits at this time (U.S. Environmental Protection Agency, 2024b). Whether or not a state has primacy where a GCS site is planned will be an important factor in the timeline (and associated expense) involved in obtaining an initial permit.

The Class VI permitting process is designed to regulate all phases of the CO_2 injection and storage process, including drilling and construction, injection, testing, monitoring, and eventual well closure. The EPA considers it the most rigorous of the UIC program permitting processes (U.S. Environmental Protection Agency, n.d.). To obtain a Class VI permit, the well operator must take a number of steps to ensure the safety and effectiveness of the CO_2 injection operation. Initially, the permittee must undertake a detailed analysis of the proposed project site to demonstrate that the geology is appropriate for CO_2 sequestration and to identify the extent of the area that may be impacted, known as the 'area of review' (U.S. Environmental Protection Agency, n.d.). The permit also contains construction and operational requirements that are intended to minimize CO_2 leakage and reduce risks such as induced seismicity (U.S. Environmental Protection Agency, n.d.). It includes requirements related to monitoring, measurement, and verification (MMV) during the injection and post-injection periods, as well as emergency response and site closure (U.S. Environmental Protection Agency, n.d.).

As of March 2024, only nineteen Class VI permits have been issued – eight by EPA and eleven by states with primacy over the Class VI permitting process (Angela C. Jones, 2024). The process for obtaining a permit can be both costly and time-consuming, taking up to six years in some cases (Jena Lococo, 2021). Further, the federal Class VI permit discussed here is required *in addition to* any permitting requirements that may exist at the state level. For example, in Pennsylvania, an injection well also requires a state drilling permit issued by the Pennsylvania

Department of Environmental Protection (Pennsylvania Department of Environmental Protection, 2021).

Notably, the Class VI permitting process for long-term carbon sequestration differs from the Class II permitting process that applies when CO_2 is used in enhanced oil recovery (EOR). The Class VI permitting process includes several requirements that the Class II process does not. Among other things, the Class VI permit requires the applicant to provide: information about potential seismicity; demonstration that the injection formation is free of fractures; continuous monitoring of CO_2 injection pressure; monitoring of the CO_2 plume front; and fifty years of post-injection site monitoring (Angela C. Jones, 2020). These more stringent permitting requirements, combined with the fact that far fewer states have primacy to issue Class VI permits, can result in a more onerous permitting process and longer timelines than are currently in place for CO_2-EOR.

5.4. Financial and Policy Considerations

Presently, the cost of implementing CCS is generally higher than any economic reward that would be expected from the market. As a result, policy plays a critical role in determining whether and how CCS will move forward. There are several government policies in place to incentivize CCS projects. These programs include both tax credits, which are designed to reduce the cost of implementing CCS, as well as market-based incentives, which aim to reward projects, like CCS, that reduce the carbon intensity of fuels. On the other hand, largely because CCS is still a nascent technology, there are ambiguities in policy that could stand as obstacles to the growth of CCS.

5.4.1. Incentives

Several incentives are in place to financially compensate companies that adopt CCS to mitigate greenhouse gas emissions. The federal government provides tax credits for each metric ton of carbon dioxide captured and permanently sequestered, while several western states have implemented low-carbon fuel standard programs that allow carbon-removal activities to create credits that can be sold. There are also voluntary private carbon markets that are working to measure and incorporate CCS into their market structure.

5.4.1.1. Federal 45Q Tax Credits

Since 2008, the United States government has offered a tax credit for companies that capture and permanently sequester carbon dioxide that would have otherwise been released to the atmosphere (Angela C. Jones & Donald J. Marples, 2023). The 45Q tax credit was expanded under the Inflation Reduction Act in 2022 to provide more significant economic incentives. For equipment placed into service between December 31, 2022, and January 1, 2033, the CCS owner can receive up to $85 per metric ton of carbon dioxide captured if certain wage and apprenticeship requirements are met (Angela C. Jones & Donald J. Marples, 2023). The tax credit increases to $180 per metric ton if the carbon dioxide was captured using direct air capture (DAC) (Angela C. Jones & Donald J. Marples, 2023).

The 45Q tax credits are still available to operators that use captured carbon as part of an EOR operation (Section 3.3), but the credit values are reduced to $60 per metric ton for CO_2 captured from industrial processes and $130 for CO_2 captured using DAC (Angela C. Jones & Donald J. Marples, 2023).

5.4.1.2. State Low Carbon Fuel Standard Programs

Several states have enacted policies that could incentivize the use of CCS. The most notable is a series of low carbon fuel standard programs adopted by the states of California, Oregon, Washington, and New Mexico. Although each state's policy is slightly different, they all operate under similar principles. Under each program, the state establishes a baseline standard for the average "carbon intensity" of fuels and mandates that all obligated parties conform to that standard (Korkut et al., 2023). Fuels with a carbon intensity higher than the benchmark generate deficits, while those that produce fuels with a carbon intensity lower than the benchmark generate credits (Korkut et al., 2023). Although no state currently considers producers of jet fuel to be obligated parties under the existing clean fuel standard programs (and thus jet fuel producers will not generate deficits), jet fuel producers may choose to participate voluntarily and generate credits, which can be sold into the market (California Air Resources Board, 2020; Oregon Department of Environmental Quality, n.d.; Washington Department of Ecology, n.d.). By incorporating CCS into their production process, producers of jet fuel may be able to reduce the carbon intensity of their products such that they may become eligible for credits under the existing programs.

5.4.1.3. Private Carbon Markets

As corporations have taken grater interest in reducing greenhouse gas emissions, private carbon markets have started to grow to offer an additional option for entities seeking to offset their emissions. In principle, their operation is simple. Private buyers and sellers exchange offset "credits" that represent a volume of greenhouse gas emissions that were either removed from the atmosphere or prevented from being released (Dawes et al., 2023, p. 1). A well-formed carbon market, then, would allow a corporation to pay for credits that would offset its emissions, thus reducing its overall climate impact.

In practice, however, private carbon markets are not likely to meaningfully incentivize CCS in the short term. First, although there are attempts to form regulated, reliable carbon markets, many largely unregulated carbon markets still exist, creating offsets of heterogenous quality and therefore undermining market reliability (Dawes et al., 2023, p. 2). Second, although the price of carbon credits can vary significantly, the highest price for a carbon credit in the United States is only approximately one-sixth the cost of capturing and sequestering carbon using direct air capture technology (Sara Budinis & Luca Lo Re, 2023).

5.4.2. Policy Obstacles

Despite the significant interest in CCS development, there remain several legal and policy barriers that could hinder the widespread adoption of CCS technology. Many of these challenges

derive from the fact that CCS is still a relatively new technology that relies on geologic features – namely pore space – that have been of little economic value previously. These challenges could add to the cost of developing projects, especially in the near future. Addressing these legal and policy shortcomings may help to increase the feasibility of CCS over the long term.

5.4.2.1. Uncertainty over Pore Space Ownership

Pore space is made up of voids in subsurface strata that can hold substances like naturally occurring minerals or injected CO_2. Historically, legal conflicts have generally focused on ownership of marketable minerals, while ownership of the pore space was often overlooked because it held little economic value. As a result, until very recently, there was little law – either in statutes and regulations, or in case law – that made it clear who owned the pore space underlying a split estate, where ownership of the mineral rights and surface rights were split among different parties. In recent years, as the value of underground storage has become more apparent, nearly half of states, including Pennsylvania, Wyoming, and Oklahoma, have determined, either by statute or in case law, that the owner of the surface estate is the proper owner of subsurface pore space (Wiseman, 2022). But a small number of states that have not revisited this issue recently have laws establishing that the owner of the mineral estate controls the pore space (Wiseman, 2022). Furthermore, a number of states have not yet considered this issue at all, and have no laws addressing whether pore space ownership belongs to the surface estate or the mineral estate (Wiseman, 2022). As a result, the preliminary step of establishing ownership over pore space (which is necessary to undertake GCS) may be fraught with potentially costly legal uncertainty in some situations.

5.4.2.2. Conflicts between Surface Estate and Mineral Estate

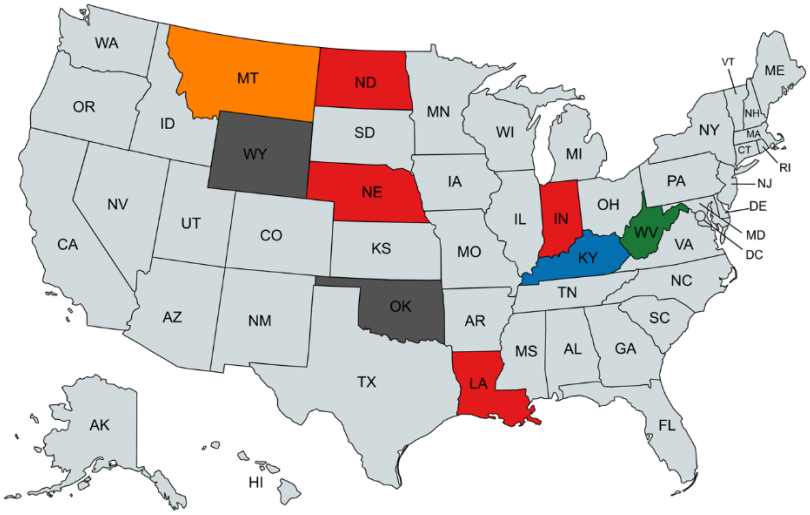
Even once pore space ownership is established, conflicts between the surface estate and the mineral estate may continue to create challenges for CCS projects. For instance, CCS/GCS operations may conflict with any mineral extraction that may occur in the vicinity of the GCS site. For example, the owner of the mineral estate may wish to drill an oil well through an underground stratum that the surface owner intends to use for carbon sequestration. Care will need to be taken to ensure that the wellbores do not allow CO_2 to leak from the storage area, which is already a stringent requirement under Class VI permits. Alternatively, there may be a more direct conflict where the surface owner wants to use pore space in a stratum from which the mineral estate owner has already extracted oil or natural gas. But conflicts may arise over capping existing well heads or any future plans the mineral owner may have to extract additional minerals from the very space where the surface owner intends to store carbon. These types of conflicts may be especially complicated because they involve debates over property use not only in the three spatial dimensions, but also in time, where projects that occur decades apart from one another may impact each other's feasibility. Although conflicts between the surface estate and the mineral estate are not new (Schremmer, 2023), conflicts related to CCS have many novel factors that may make them

more complicated to resolve. These conflicts have the potential to delay and add costs to CCS projects as the law works through the questions necessary to resolve them.

5.4.2.3. Unitization/Compulsory Pooling

The geological formations conducive to GCS can be large and cannot be expected to align with property boundaries. As a result, GCS project operators will often need to obtain rights from multiple property owners for a storage operation. Such a situation, in which a developer must obtain consent from multiple property owners in order to pursue a project, creates conditions for what has come to be known as the "holdout" problem in property law (Collins & Isaac, 2012). In those cases, property owners have an incentive to increase their bargaining power with the developer by withholding consent as long as possible to drive up the price they are likely to receive (Collins & Isaac, 2012).

To address the holdout problem, some states allow for eminent domain authority to be used for the unitization of multiple properties for GCS programs. In these states, a developer would need to obtain consent from a certain percentage of pore space owners. Once that threshold has been reached, the developer can seek authorization from a state authority to compel the remaining property owners to allow the use of their pore space for fair market value. This process is sometimes referred to as compulsory pooling. As shown in the map below, states have taken different approaches to unitization, and many states have yet to consider the issue.



IN,LA,ND,NE	Compulsory pooling forced by commission
KY	Compulsory pooling at 51%
MT	Compulsory pooling at 60%
WV	Compulsory pooling at 75%
OK & WY	No eminent domain

(Ind. Code § 14-39-1-7(b); La. Rev. Stat. § 30:1108; N.D. Cent. Code § 38-22-10; Neb. Rev. Stat.§ 57-1612; Kentucky Rev. Stat. § 353.806; Montana Code Ann. §§ 82-11-101(16) (effective on occurrence of contingency); 82-11-204(1); West Virginia Code Ann. § 22-11B-19; Okla. Stat. tit. 27A § 3-5-106(D); Wyo. Stat. Ann. § 35-11-316)

5.4.2.4. State Permitting

In addition to the federal Class VI permit discussed above, GCS operations often require state permits before beginning operations. These permitting processes can result in additional delay and expense. For example, in Pennsylvania, GCS operators must obtain a state drilling permit issued by the Pennsylvania Department of Environmental Protection before commencing operations. That permitting process includes a geologic analysis, and a mechanical integrity assessment of the well, including analysis of the Casing and Cementing Plan. It also includes an Erosion and Sedimentation Control Plan (Pennsylvania Department of Environmental Protection, 2021).

5.5. CCS and CORSIA sustainability criteria

One impetus for integrating CC(U)S into SAF supply chains is improving upon the extent to which SAFs address the first sustainability criterion put forth by CORSIA, greenhouse gases. Specifically, SAFs must achieve at least a 10% reduction in life cycle greenhouse gas emission relative to baseline emissions for aviation fuels (*ICAO Document - CORSIA Sustainability Criteria for CORSIA Eligible Fuels*, 2024). However, incorporating CC(U)S may simultaneously address or improve other sustainability criteria. Of course, for any CC(U)S option to be effective, it would need to address criteria 3: greenhouse gas emissions reduction permanence. Arguably, in terms of CO_2 storage or utilization options, GCS may be the most accepted form of emission reduction permanence, as strict guidelines are in place to ensure permanence (Sections 3, 5.3) and emissions accounting is more straightforward than if CO_2 is used in products where there may be uncertainty in its end fate. CC(U)S efforts would need to consider associated water consumption (Criteria 4), which is not expected to be an issue; water demands are not excessive, and EPA Class VI regulations for CO_2 injection are designed to avoid adverse impacts to underground sources of drinking water. However, investment in technologies like direct air capture (DAC) instead of CO_2 capture from SAF production processes would have a higher water footprint. DAC was not explicitly considered in this study to constrain the scope to point-source capture, but can be considered as an alternative investment to point-source CCS in future work.

6. Conclusions

CCS has broad potential to enable carbon-neutral to carbon-negative SAFs, but there are several foreseeable challenges to integrated SAF-CCS paths. Many of these challenges relate to geologic storage of injected CO_2, not specific to SAFs, including economic cost, permitting, pore space ownership, pipeline construction, and long-term liability risk. We expect that lingering legal and regulatory questions are likely to be addressed by policymakers and the CCS industry in the

coming years as interest in CCS/GCS expands and permit applicants continue to increase. However, long-term project economics will remain highly variable by specific SAF and location, and must consider that current 45Q federal tax credits are only in place for 12 years. The process for attaining Class VI permits can also add substantial costs and can delay injection, given the amount of time and engineering effort needed to demonstrate proper siting and long-term storage security. Utilization options, particularly EOR, may be more mature, but the CO_2 used will need to be obtained from direct air capture or from a biogenic source in order for it to demonstrate necessary reduction in carbon intensity score required to qualify for as a SAF or low carbon aviation fuel under CORSIA. Coordinating the start of CO_2 capture with operational GCS will likely be a logistical challenge, particularly for early adopters, as well as for projects where capture, transport, and/or storage are handled by different entities.

Life cycle analyses to date indicate that the use of CCS in SAF production, particularly for SAFs produced from forest residue feedstock, can generate negative carbon intensity scores (net negative emissions). Future studies can consider a wider spectrum of SAF feedstocks, conversion technologies, CO_2 capture technologies, and means of utilization or storage to identify where CCS may be more or less favorable. In particular, prior studies have generally assumed literature values for transport and storage emissions, and have neglected detailed consideration of available and accessible CO_2 storage options. Naturally, CI score reductions will remain theoretical if CCS is infeasible due to a lack of economically viable CO_2 storage sites and/or infrastructure. Project-specific analyses that consider specific SAF production pathways (location, feedstock, conversion technology) alongside available regional CCS options will be critical to understanding logistical viability in addition to emission reductions.

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