

**A COMPREHENSIVE REVIEW OF CARBON CAPTURE & SEQUESTRATION:
WHERE WE ARE &
WHERE COULD WE GO?**

by
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1. ABSTRACT

Carbon capture and sequestration, or CCS, is a technology that has been highlighted by the IPCC (2018) as a critical technology that offers the immediate opportunity to mitigate carbon dioxide emissions from industrial sources and fossil fuel burning power plants. A transition away from fossil fuels cannot occur instantly, instead it must be gradual given society's high dependency on fossil fuels, and the lack of equal and equitable access to sustainable replacement technologies. Society must utilize a variety of readily available mitigation, adaptation, and decarbonization tools used together to address climate change while recognizing that carbon dioxide emissions will be reduced but they will not be eliminated in the near term. CCS is one of these readily available technologies to reduce carbon dioxide emissions. This capstone will provide a detailed overview of the current technical and economic aspects of CCS. Followed by highlighting, four case studies that show how varying captured emission types and varying transportation distances impact project economics and compatibility with existing tax credit levels.

It was found that while CCS is technically viable; the economics, specifically the capture costs, offer the greatest hurdle and uncertainty in further implementing CCS. Results from analysis suggest, in the near-term increasing the current tax credit from \$50 per ton of carbon dioxide sequestered to \$85 per ton of carbon dioxide sequestered would make applying CCS to emissions from bioethanol, ammonia, lime, and natural gas processing economic on a mean total project cost basis. These sectors account for 15% of the annual carbon dioxide emissions from industry and power plants. From a long-term economic standpoint, increasing the tax credit would also spur additional implementation, which in turn would result in decreasing capture costs, a trend seen in already with power plant capture costs and more broadly in other renewable technologies such as onshore wind and solar PV. Finally, from a storage component, it was found that the sedimentary basins within the United States offer an abundance of storage space.

Key words: Carbon capture sequestration, CCS, decarbonization, mitigation, carbon dioxide

Primary reader & mentor: Dr. Thomas Jenkin

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3. Introduction

The power generation and industrial sectors account for nearly 2,600 million metric tons of carbon dioxide emissions in 2020 (EPA, 2021b). These fossil fuel sourced emissions are part of the reason scientists at the IPCC have issued warnings that the planet is on an unsustainable warming path of greater than 1.5 degrees Celsius (IPCC, 2021). Over the last the decade, the IPCC has also been developing various warming scenarios modeling the impacts of varying levels of carbon dioxide emissions and varying degrees of emissions mitigation measures such as the application of carbon capture, utilization, and sequestration (CCUS) (IPCC, 2018). This process of CCUS involves trapping carbon dioxide emissions, transporting these emissions to be reused in other industrial processes (utilization), or to permanently sequester these emissions underground (sequestration) (Duncan & Morrissey, 2011). In the case of sequestration, these emissions are sequestered in a super fluid state within a porous and permeable rock formation, such as a sandstone, that is laterally bounded as well as capped by an impermeable rock formation such as a shale (Duncan & Morrissey, 2011). Currently, the United States has two wells that have a lifetime permitted capacity of 7 million metric tons of carbon dioxide which equates to less than 0.2% of 2020 annual carbon dioxide emissions (EPA, 2022a). Given the high volume of emissions from the power generation and industrial sectors and an urgent need from a climate standpoint to mitigate emissions, CCUS could offer significant mitigation potential.

Given the significant potential of CCUS, as a tool laid out by the IPCC to combat climate change, the purpose of this capstone project will be to focus on carbon capture and sequestration within the United States, define the current technical and economic framework in place, followed by identifying and analyzing four case studies, with the ultimate intention of proposing policy refinement to expand the use of CCS. Rapid expansion and immediate implementation of this technology could be critical to immediately curbing emissions from the industrial and power generation sectors with the two-fold goal of averting warming of greater than 1.5 degrees Celsius while minimizing negative economic consequences.

4. Literature Review

This section will provide a highlight of relevant background information concerning the technical and economic aspects of carbon capture and sequestration. Technical topics that will be explored include general background, technologies for emissions capture, transportation options, types of underground injection wells, and methods to sequester the captured carbon dioxide emissions underground. Once the technical foundation has been established, the literature review will continue by assessing capture costs, transportation costs, sequestration costs, and the existing tax credits in place.

4.1 Technical Overview of Carbon Capture & Sequestration

4.1.1 General Background

Carbon capture and sequestration is a series of technologies that when combined are effective at mitigating carbon dioxide emissions from large stationary sources (EPA, 2017). With CCS, carbon dioxide emissions are trapped from large stationary sources, then compressed and transported to a suitable site, where the emissions are pumped a mile or more beneath the surface into a porous and permeable formation that is capped with an impermeable layer above and bounded on all sides to prevent significant lateral and any upward migration (EPA, 2017). This technology is just one of many important tools available as the country and the world work towards mitigating carbon dioxide emissions. As mentioned above, CCS is best used to capture and sequester emissions from stationary sources. In 2019, it was estimated that stationary sources within the industrial and power generation sectors accounted for 48% (or 3,152 million metric tons of carbon dioxide equivalent) of the total annual GHG emissions for the United States (EPA, 2022c). So, there is a significant opportunity in terms of potential emissions that could be captured and mitigated.

CCS can be utilized to capture, transport, and sequester carbon dioxide emissions in the power generation sector, at oil and natural gas refining and processing plants, chemical plants, pulp and paper plants, cement plants, and metal processing plants among others (Global CCS Institute, 2015). For better

scale and perspective, if CCS were applied to a 500 MW coal fired power plant operating at an average capacity factor of ~60%, emitting 3 million tons of carbon dioxide per year; the emissions mitigated; assuming 90% mitigation efficiency, would be equal to waiting 10 years after planting more than 62 million trees, that take up 210 square miles or over three times the area of Washington D.C. (EPA, 2017 & Pedraza, 2019). Alternatively, it would be the same as avoiding the power-related emissions to more than 300,000 average American homes (EPA, 2017). It is also important to note that 3 million tons of carbon dioxide at 1 atm and 25 degrees C versus sequestered underground at a depth of 5,000 ft (67 degrees C and 157 atm assuming normal temperature and pressure gradients) is vastly different in terms of density and volume. In fact, the volume would be 137 times smaller when stored at those depths and pressures. These changes in volume are reinforced with Figure 1, below, which highlights the density and volume changes of emitted carbon dioxide in a gaseous form to sequestered carbon dioxide in supercritical form (NETL, n.d.).

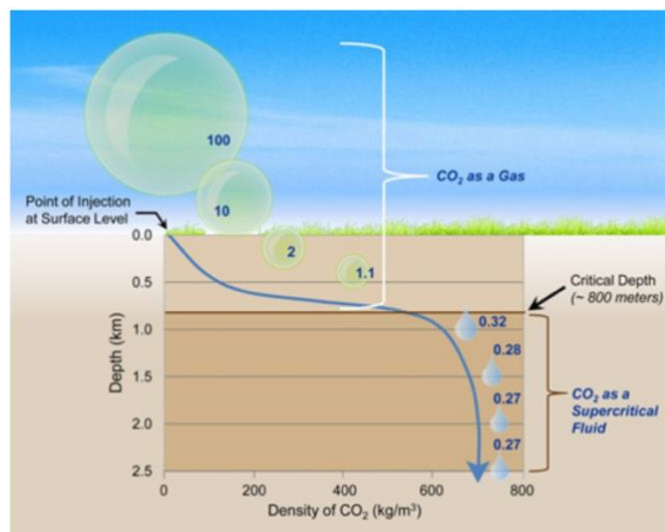


Figure 1: Depth & Pressure Effects of CO2
 The blue numbers show changes in CO2 volume with depth. Source: Figure from NETL, n.d..

CCS offers an immediate opportunity to mitigate emissions from power plants and from other industrial sources as less carbon intensive power sources and industrial processes are researched, developed, and economically demonstrated. There is a clear need and opportunity for CCS, but it is not

the single the answer to carbon dioxide emissions, in the coming the sections, technologies and costs will be discussed, which will set the tone to analyze the economic viability of CCS.

4.1.2 CCS Capture Technologies

There are three main capture types: post-combustion carbon capture, precombustion carbon capture, and oxy-fuel combustion carbon capture. This section will outline these main types and highlight an additional technology that is in development, direct air capture. The first and most common form of carbon capture is post-combustion carbon capture. The process involves trapping flue gases after a fossil fuel is combusted, separating the carbon dioxide from the other gases, thus allowing for compression and transportation of the captured and separated carbon dioxide (Ronca & Mancini, 2021). While this process can be deployed on both new and existing facilities, it does require large (capitally intensive) equipment and does reduce the efficiency of the industrial process in question (Ronca & Mancini, 2021). Costs for this method of carbon capture will be examined later in the literature review.

The second form of carbon capture is precombustion carbon capture. This process is where fossil fuels such as coal, oil, and natural gas are heated with steam and oxygen, forming synthesis (or syn) gas composed of carbon dioxide, carbon monoxide, and hydrogen (Ronca & Mancini, 2021). The syn gas is then processed where a chemical reaction converts water into hydrogen and the carbon monoxide into more carbon dioxide (Ronca & Mancini, 2021). The hydrogen is then separated and can be sold, with the remaining carbon dioxide ready for compression, transport, and sequestration (Ronca & Mancini, 2021). Overall, this process is more efficient than post-combustion capture, is more suitable for implementation at new industrial sources, but is also comparatively more expensive (Ronca & Mancini, 2021).

The third method for carbon capture is oxy-fuel combustion carbon capture. This process involves combusting fossil fuels, usually at power plants, in a gas mixture containing pure oxygen instead of regular air (Ronca & Mancini, 2021). The resulting products from the combustion process are only carbon dioxide and water which can easily be separated through compression and cooling (Ronca & Mancini, 2021). Some aspects of the oxy-fuel combustion carbon capture process are cheap but overall,

the process is higher cost, due to the cost of pure oxygen, and as of 2020 has not been proven for large scale operations (Ronca & Mancini, 2021).

Finally, a fourth and emerging technology called direct air capture (or DAC) involves capturing carbon dioxide straight from the atmosphere. The operation is set up independent of an industrial emissions source (Budinis, 2021). There are two types of DAC: liquid and solid DAC. Liquid DAC involves pushing air through chemical solutions such as a hydroxide solution which in turn separates the carbon dioxide while returning the purified air back to the environment (Budinis, 2021). Solid DAC utilizes sorbent filters that chemically attract and bind with the carbon dioxide, the filters are then heated under a vacuum, releasing the carbon dioxide which is captured, transported, and sequestered (Budinis, 2021). The technology is still in the demonstration phase, but one large scale facility slated to commence operations in 2024, will capture 1 million tons of carbon dioxide annually, and is being developed in the United States by Carbon Engineering and Occidental Petroleum (Budinis, 2021). It is also much more expensive and energy intensive than other carbon capture technologies, though costs are expected to fall (Budinis, 2021). With additional demonstration and reductions in the cost to manufacture the technology, direct air capture could be an integral part of CCS's future implementation, since emissions could be captured from the air and sequestered without transporting the emissions over large distances.

4.1.3 CCS Transportation Options

Now that the methods of capturing carbon dioxide emissions have been identified, next the methods of transportation will be covered. Carbon dioxide can be shipped in either solid, liquid, gaseous, or supercritical form via pipeline, truck, tanker, or rail, however, the most common method to transport carbon dioxide is in a supercritical form through pipelines (Global CCS Institute , n.d.). Transporting carbon dioxide via pipeline is either done through pipelines exclusively built for carbon dioxide or through repurposed/underutilized or abandoned natural gas infrastructure (Kenton & Siltan, 2022). Carbon dioxide pipelines pose no higher risk than when transporting hydrocarbons. The main risk is maintaining the purity of the carbon dioxide within the pipeline to prevent corrosion or clogging (Ronca

& Mancini, 2021). Currently, there are 50 carbon dioxide pipelines operating in the United States, which represents over 4,500 miles of pipeline, capable of moving about 68 million tons annually (Wallace, Goudarzi, Callahan, & Wallace, 2015) & (Global CCS Institute, n.d.). This number could significantly change if existing natural gas infrastructure is repurposed for transporting carbon dioxide.

4.1.4 Types of Underground Injection Wells

Before examining the specific methods of geologic sequestration of carbon dioxide emissions, it is important to step back and outline the program that dictates the rules and regulations to do so. Injection of carbon dioxide for permanent sequestration is part of the underground injection control (UIC) program which falls under the purview of the EPA and aims to protect sources of drinking water (EPA, 2022d). There are six types of Underground Injection Control wells: Class I applies to industrial and municipal waste disposal, Class II applies to oil and gas injection wells, Class III applies to solution mining wells, Class IV applies to shallow hazardous and radioactive waste injection wells, Class V applies to non-hazardous fluids into or above underground sources of drinking water, and finally Class VI applies to the geologic sequestration of carbon dioxide (EPA, 2022d).

4.1.5 CCS Methods of Sequestration

Thus far, CCS has been defined, the applications have been identified, capture technologies have been introduced, methods for transportation have been reviewed, and the various types of underground injection wells have been defined. The final component to CCS that has yet to be defined is the sequestration component. Prior to sequestration, the carbon dioxide must be in a supercritical state. Typically, if it is transported via pipeline, it is already in this state, however, to maintain this fluid state, it must be sequestered at a minimum depth of 800 meters or 2,600 feet (NETL, n.d.). In addition to the depth requirement, the formation the carbon dioxide is sequestered in must be overlaid by an impermeable confining formation such as a clay-rich shale (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). Carbon dioxide can be sequestered in basalt formations, organic rich shales, un-mineable coal seams, oil and gas reservoirs, and saline reservoirs

(NETL, n.d.). This capstone will focus primarily on saline reservoirs as these offer the highest storage potential in terms of volume.

Once the carbon dioxide is in a porous and permeable formation overlaid by an impermeable layer, lateral containment must be considered. There are four types of lateral containment trapping: buoyant trapping, residual trapping, solubility trapping, and mineralization trapping. Buoyant and residual trapping are the two primary methods for sequestering carbon dioxide underground (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). Buoyant trapping involves containment on all sides in addition to an impermeable and nonporous top seal (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). Fundamental knowledge of geology dictates that forms of lateral containment include structural traps such as domes or stratigraphic traps such as facies changes or truncations. The second method is residual trapping, which traps the carbon dioxide as individual droplets within the formation pore space by capillary forces (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). This trapping mechanism consists of three classes based on formation permeability (Class I has a permeability greater than 1 Darcy, Class II has a permeability between 1 millidarcy and 1 Darcy, and Class III has a permeability of less than 1 millidarcy) (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). These two trapping mechanisms are depicted in Figure 2. Research from the US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) indicates that the mean national storage volume potential for buoyant trapping is 44 GT while the mean national storage potential for residual trapping is 3,000 GT. Two other forms of trapping exist: solubility trapping and mineral trapping. Solubility trapping involves the dissolution of carbon dioxide in water formation for storage purposes and depends on the formation water's salinity, pressure, and temperature (Zhang & Song, 2014). Mineral trapping involves the precipitation of carbon dioxide into a stable mineral phase through reactions with the formation's constituent minerals and organic matter (Zhang & Song, 2014). These two trapping mechanisms have not been evaluated in terms of storage

potential by the USGS given the difficulty in assessing/understanding the drivers of each trapping mechanism on a regional basis.

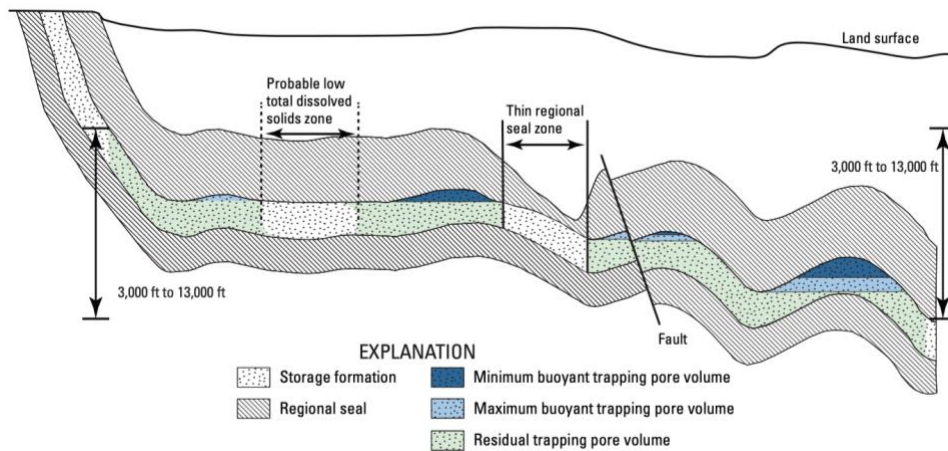


Figure 2: Schematic Cross-Section Highlighting the Geology of Buoyant & Residual Trapping
 Source: Figure from US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b

Figure 3 (below) wraps up the technical overview of CCS and is a schematic diagram that depicts the basics by highlighting an emissions facility (power plant) where emissions are captured, pipelines transporting the captured emissions to injection wells, where the emissions are sequestered underground. As the technical foundation of CCS has now been established, the costs associated with capture, transport, and sequestration will be discussed in the next section of the literature review. Further reading on analogue technologies to CCS and current Class VI injection wells is available in the Annex.

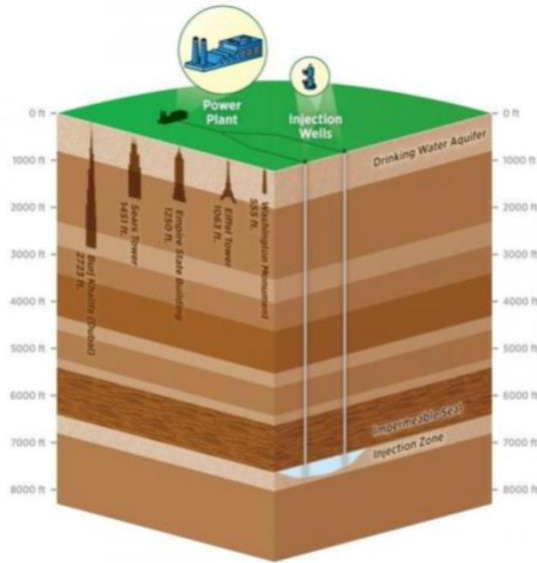


Figure 3: CCS Schematic Diagram
 Source: Figure from EPA (2017).

4.2 Economic Overview of Carbon Capture & Sequestration

This section of the literature review will highlight the economic aspects of carbon capture and sequestration. It will first discuss the economics of capturing carbon from varying emission sources, followed by discussing the transportation costs, followed then by discussing the costs with sequestration, before finishing with an overview of current policy and tax credits in place.

4.2.1 CCS Capture Costs:

Through this literature review, it became clear that raw data surrounding capture costs were limited in nature. As a result, models were constructed based off this limited data to extrapolate a range of capture costs across various industrial sectors. Two main sources will be highlighted below to provide a range of modeled capture costs. Capture costs typically account for most of a CCS project's costs and the primary drivers impacting capture costs are the carbon dioxide purity of the emissions stream or flue gas and the number of reactor exhaust streams (Pilorgé, et al., 2020). The higher the purity and the lower number of exhaust streams to capture, the lower the capture costs. Figure 4 from Pilorgé et. al (2020) highlights the modeled capture costs of several different industrial types versus carbon dioxide flue gas molar composition, not plotted are costs to capture emissions from bioethanol plants, as the authors

indicated these costs are essentially zero and the flue gas composition is 99+% carbon dioxide. The IECM data from power plants were the basis of these cost models; modeled the cost of carbon dioxide avoided; accounted for capture/separation, compression/transportation, and sequestration; and were then extrapolated out for additional industrial sectors (Pilorgé, et al., 2020). Emissions from ammonia and hydrogen plants offer the next lowest modeled capture costs while emissions from natural gas combined cycle power plants offered the highest modeled capture costs of the industrial sectors studied (Pilorgé, et al., 2020).

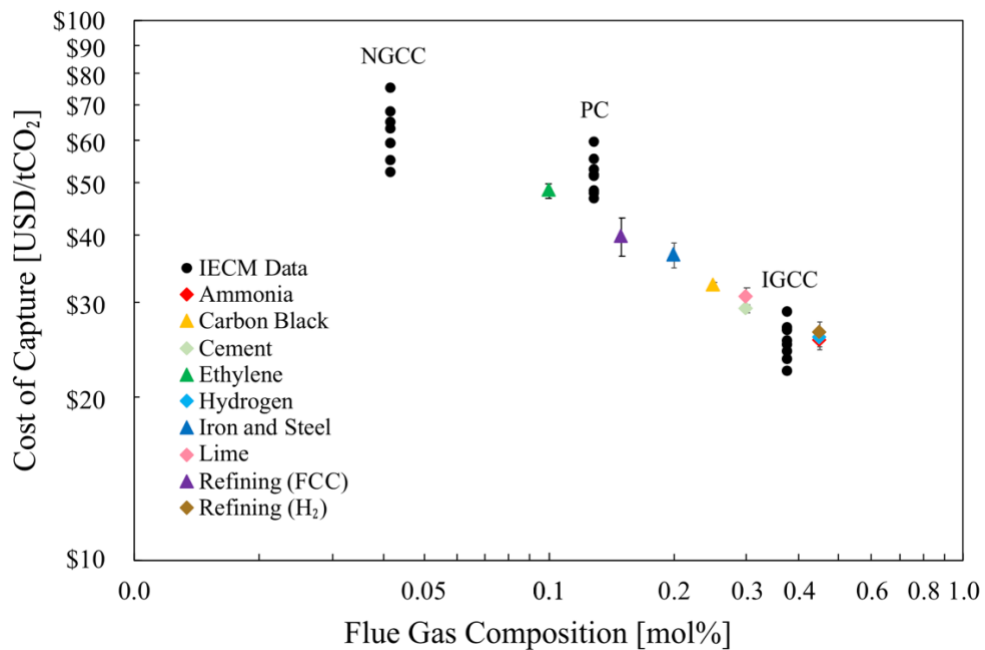


Figure 4: Cost of Capture Vs Flue Gas Comp
Source: Figure from Pilorgé, et al., 2020

Alternatively, a study from Moch et. al. (2022) provides additional modeled capture cost data, in some instances provides similar approximations to the study from Pilorgé et. al (2020) but also indicates a noticeably larger spread of uncertainty in modeled capture costs for other industrial sources. Figure 5 highlights these modeled capture costs as well as current and proposed tax credits (which will be addressed in a later section of this literature review). While the selected industrial sectors are not identical to the study from Pilorgé et. al. (2020), there is substantial overlap, and the natural gas processing sector was analyzed as well though this second study. Research from Moch et. al (2022)

further indicates that uncertainty may be much larger for some technologies, such as cement and steel. This uncertainty in capture costs can be attributed to annual carbon dioxide emissions from the facility, the age of the facility, and the costs of fuel/electricity to run the facility (Moch et. al., 2022). In other words, economies of scale matter; the more annual emissions, the younger the facility, and the cheaper the cost of fuel/electricity equates to lower capture costs. This statement would also apply to heat intensive industrial processes such as power generation, cement, and iron & steel. Finally, for the analysis within this capstone, modeled costs for capture will be focused upon for natural gas combined cycle power plants, pulverized coal power plants, natural gas processing facilities, bioethanol, cement, hydrogen, iron & steel, and lime industries.

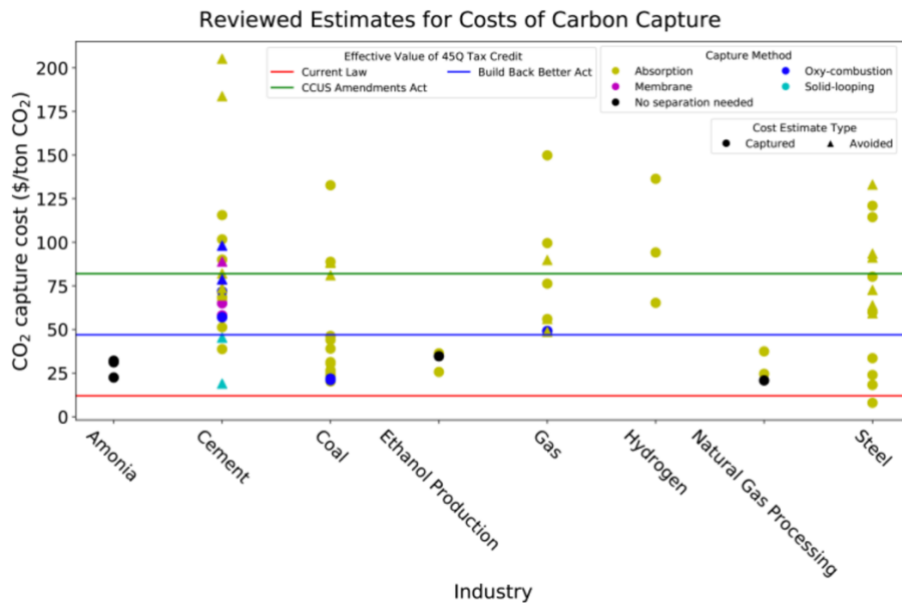


Figure 5: Additional Capture Costs by Sector
 Source: Figure from Moch, Xue, & Holdren, 2022

Finally, it is important to examine historical trends in capture costs. Figure 6 highlights dropping capture costs within the power plant sector. This data set shows capture costs initially were at \$110 per ton of carbon dioxide in 2014, followed by three years later capture costs decreasing by 41% to \$65 per ton of carbon dioxide, and finally are projected to decrease an additional 31% to \$45 per ton of carbon dioxide for carbon captured by 2025-2027 (Baylin-Stern & Berghout, 2021). This 60% decrease

corresponds to similar percentage drops in the costs of other renewable technologies such as wind and solar photovoltaics (IRENA, 2021).

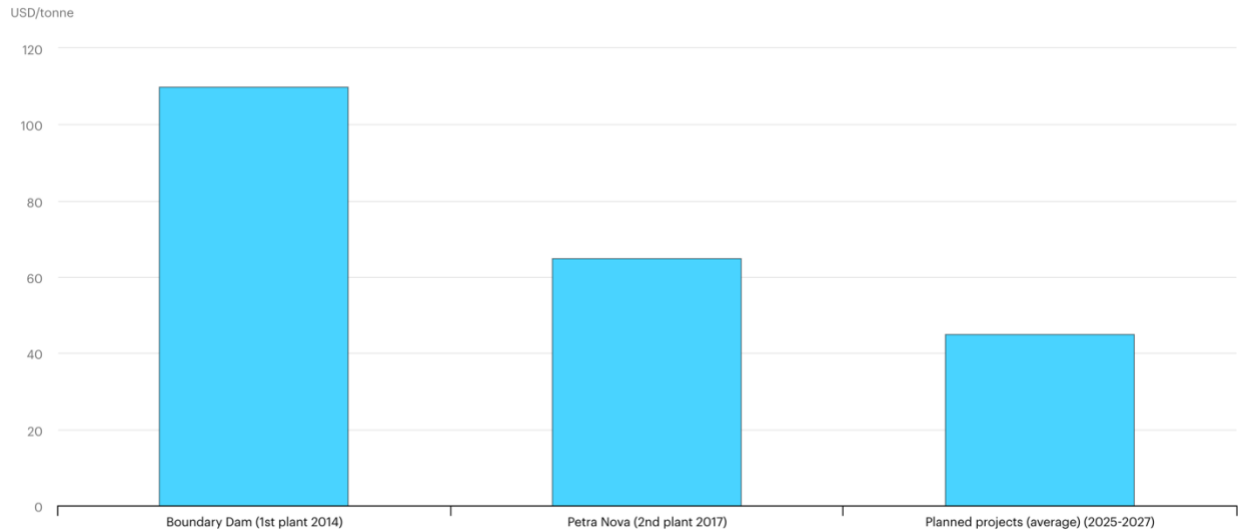


Figure 6: Actual & Projected Carbon Capture Costs from Select Power Plants
Source: Figure from Baylin-Stern & Berghout, 2021

4.2.2 CCS Transport Costs:

Moving on from capture costs, this section will briefly address transport costs. In the interest of brevity, pipelines will be the only transportation method covered, since it is the preferred method of transporting large quantities of captured carbon dioxide emissions. Pipeline costs are primarily driven by distance emissions must be transported and overall annual volume of carbon dioxide transported.

Table 1: Range of Pipeline Costs for Variably Sized CCS Projects
Source: Schmelz, Hochman, & Miller, 2020

Annual Volume of CO ₂ Emissions	Low-End Cost Estimate (USD/ t CO ₂ /250 KM of pipe)	Mean Cost Estimate (USD/t CO ₂ /250 KM of pipe)	High-End Cost Estimate (USD/ t CO ₂ /250 KM of pipe)
3 Mt of CO ₂ per year	4.4	5.9	7.4
10 Mt of CO ₂ per year	2.3	3.1	3.8
30 Mt of CO ₂ per year	1.3	1.8	2.3

Table 1 highlights the low-end, mean, and high-end pipeline costs associated with variably sized CCS projects, normalized in US dollars per ton of carbon dioxide per 250 kilometers of pipe (Schmelz, Hochman, & Miller, 2020). One can see that economies of scale are important, as the larger the project in

terms of annual carbon dioxide transported, the lower the pipeline costs. Two final notes to consider here, these costs apply for onshore CCS projects as off-shore CCS projects will have higher costs given the risk and complexity of working off-shore and compression and maintenance costs are already added in (Schmelz, Hochman, & Miller, 2020).

4.2.3 CCS Sequestration Costs:

Next the third and final cost component of CCS will be discussed briefly. Sequestration costs noted below will account for all costs associated with the following activities: site preparation, injection and monitoring well drilling, science collection, model creation, and yearly monitoring and maintenance costs. The following table, Table 2, summarizes the sequestration costs for sequestering emissions onshore in a depleted oil and gas reservoir as well as in a saline reservoir. Costs for onshore oil and gas reservoirs are typically lower given that there is usually more well control in depleted reservoirs which means more of the critical reservoir and geologic information is known, thus the need to collect this information is less which in turn reduces the overall sequestration costs (Schmelz, Hochman, & Miller, 2020). Finally, as with transportation costs, performing sequestration offshore would result in higher costs given the higher risk and uncertainty of the operations (Schmelz, Hochman, & Miller, 2020).

*Table 2: Range of Costs Associated with Sequestration in Varying Settings
Source: Schmelz, Hochman, & Miller, 2020*

Reservoir Type	Low-End Cost (\$/ t CO2)	Median Cost (\$/ t CO2)	High-End Cost (\$/ t CO2)
Depleted Oil & Gas Reservoir	1	5	13
Saline Reservoir	3	6	15

4.2.4 CCS Tax Credit Policy:

Now that the costs of CCS have been analyzed by each component, it is worth discussing the current tax credit policy in place within the United States for CCS. Given that CCS is a relatively new technology, it is common, like with wind and solar, for governments to offer a subsidy to incentivize the implementation of an emerging technology. This subsidy and in turn increased implementation of technology often drives technological evolution and improved economics of the technology in question.

For CCS, the main tax instrument in place within the United States is the sequestration tax credit known as 45Q and accounts for all components of CCS (capture, transport, and sequestration) (Jones & Sherlock, 2021). The current 45Q tax credit pertains to facilities that have been operating to geologically sequester carbon since October 3, 2008; and includes two main types of geologic sequestration, tying back to Class II or Class VI injection wells (Jones & Sherlock, 2021). Permanent sequestration of carbon dioxide, which pertains to Class VI injection wells, receives a tax credit of \$31.77 in 2020 per metric ton of carbon dioxide, increasing to \$50 per metric ton of carbon dioxide by 2026 (Jones & Sherlock, 2021). While geologically sequestered carbon used for Class II wells (for enhanced oil recovery) receives a tax credit of \$20.22 per metric ton of carbon dioxide in 2020, increasing to \$35 per metric ton of carbon dioxide in 2026 (Jones & Sherlock, 2021). As of November 2020, tax expenditures associated with 45Q were less than \$50 million but were expected to increase to \$2.3 billion for a period between 2020 and 2029 which provides a forecast into the longer-term implementation of CCS (Jones & Sherlock, 2021). This low payout from a tax expenditure standpoint coupled with the low implementation of the technology could indicate that further economic incentives are necessary to spur additional application, demonstration, and development of the technology. To that end, proposals to modify 45Q in 2021 ranged from \$75 and \$175 per ton of carbon dioxide sequestered, with most bills in Congress coalescing to between \$75 - \$85 per ton of carbon dioxide sequestered (McMahon, 2021).

5. Methodology

The first step was to conduct an expanded literature, providing foundational knowledge on the technical and economic aspects of CCS. After this foundation is established, the literature review will expand and utilize ArcGIS to assess the amount and variety of industrial sources, the location of these emission sources relative to the major sedimentary basins, and how much storage potential is available in each of the major geologic basins. Simply put, this can be quantitatively broken down into two main components: an emissions component and a storage component.

Once this high-level understanding has been established, case studies will be developed and analyzed to model the impacts to project costs for varying emissions sources and varying transport distances. Low-end, mean, high-end costs (in \$ per ton of carbon dioxide) were estimated to provide a range of expected project costs. These costs were then compared back to the current tax credit level to assess economic viability and identify any potential policy proposals that would expand the economic feasibility of CCS. In addition to understanding varying project costs, in each case study; geologic parameters, and a range of storage potential for prospective formations were evaluated with potential storage formations identified based off an analysis of these variables. It is important to note that in some instances, these case studies represent proposed and/or planned projects. Finally, these case studies serve to demonstrate the impact CCS could have on reducing carbon dioxide emissions within the industrial and power plant sectors.

Four case studies were created for this project. Case Study 1 will focus on capturing and transporting bioethanol emissions from several states within the Upper Midwest and sequestering these emissions within the Williston Basin. This case study will analyze the economic feasibility of low to no capture costs but high pipeline transportation costs. This project is modeled after the proposed Summit Carbon Solutions project (Summit Carbon Solutions, 2022). Case study 2 focuses on capturing and sequestering ammonia and hydrogen emissions in the Louisiana Gulf Coast. This case study analyzes the economic viability of capturing pure carbon dioxide emissions from ammonia and hydrogen sources while transporting over relatively shorter distance to be sequestered in the onshore portion of the Gulf Coast Basin. Case Study 2 is a model which represents an idea that has been identified as highly feasible by numerous sources in the oil and gas industry but has no formal project proposal (Denbury Resources, 2022). Case Study 3a will assess capturing carbon dioxide emissions from pulverized coal sourced power plants, so even higher capture costs, while transporting over relatively short distances and sequestering within the DJ Basin of eastern Colorado and southeast Wyoming. Case Study 3a has no analogue idea or proposed project and is meant to be used as a proxy for policy reformation of the 45Q tax credit as part of

a larger effort to capture and sequester emissions from the power sector, which continues to represent a high percentage of carbon dioxide emissions. Finally, Case Study 3b, simply swaps out the coal-fired power plants in Case Study 3a for natural gas fired power combined cycle gas turbine (CCGT) plants with all other variables being held constant. The purpose of this study is to evaluate the economics of CCS for natural gas fired power plants given recent shift away from coal fired power plants and if a ban on coal fired power plants is ever considered.

For each case study, ArcGIS was used to analyze the location of these emissions relative to the favorable areas for several geologic formations within each sedimentary basin. Hypothetical pipelines were then planned and measured accordingly, linking the various emissions sources, and transporting the emissions to favorable sequestration areas. Further analysis was then conducted weighing various geologic inputs and overall formation storage potential to select the most favorable geologic formation or formations to sequester within. Once these parameters were defined; low-end, mean, and high-end capture costs, transport costs, and sequestration costs were applied from the literature review to estimate a range of total project costs. These costs were then analyzed and compared back to the current \$50 per ton of carbon dioxide 45Q sequestration tax credit. Based off the identified sequestration formations, a range of storage potential volumes and resulting range of storage years were then calculated. Finally, based off the analytical results, proposals to refine the current policy surrounding carbon capture and sequestration within the United States were made.

6. Analysis & Results

This section will start by analyzing total CCS project costs broken out by industrial sector, then analyze long-term cost reductions sourced by decreasing capture costs, and finally industrial sources of carbon dioxide emissions. Second, the bulk of this section will focus on the analysis of the four cases studies that were introduced in the previous section. Finally, a summary of those case studies with implications for policy going forward will be presented.

6.1 Background & Applications

Before examining specific case studies, the next sections will lay the groundwork for how CCS can be a useful tool in mitigating carbon dioxide emissions. Understanding total project costs by industrial sector and projected cost reductions will provide an understanding of where CCS can be implemented economically. Understanding where these industrial emissions come from will also give one a sense of how much potential CCS could assist in emissions mitigation.

6.1.1 Analysis and Synthesis of Capture Costs

Given the importance of capture costs, this section will highlight in Figure 7 various industrial sources and a range of expected project costs. The only variable in this analysis is modeled capture costs per emissions source. Cost of transportation and sequestration varied only on a low-end, mean, and high-end basis. Pipeline costs are for onshore 10 Mt annual emissions sized projects with a planned 250 km of pipe laid and sequestration costs were for onshore saline reservoirs. Except for natural gas power plants, all low-end total project cost estimates arrived lower than the current 45Q tax credit of \$50 per ton of carbon dioxide sequestered. The mean total project costs for emissions from bioethanol, ammonia, lime, and natural gas processing all came in under the current 45Q tax credit of \$50 per ton of carbon dioxide sequestered. Finally, none of the high-end project costs for any of the select emissions sectors came in lower than the current 45Q tax credit of \$50 per ton of carbon dioxide sequestered. It is also interesting to note, the modeled costs for hydrogen, iron & steel, coal power plants, and natural gas power plants saw a high degree of uncertainty in project costs which traces back to a wide range of uncertainty for the modeled capture costs. Should the tax credit be increased to \$85 per ton of carbon dioxide as work from McMahon (2021) suggests, all modeled project costs for bioethanol, ammonia, lime, and natural gas processing emission sources become economically viable. However, the remaining emissions categories (hydrogen, iron & steel, coal power plants, and natural gas power plants) remain unchanged in terms of their economic viability. Pushing the tax credit even higher to \$175 per ton of carbon dioxide sequestered makes all emissions sources and all ranges of project costs economically viable.

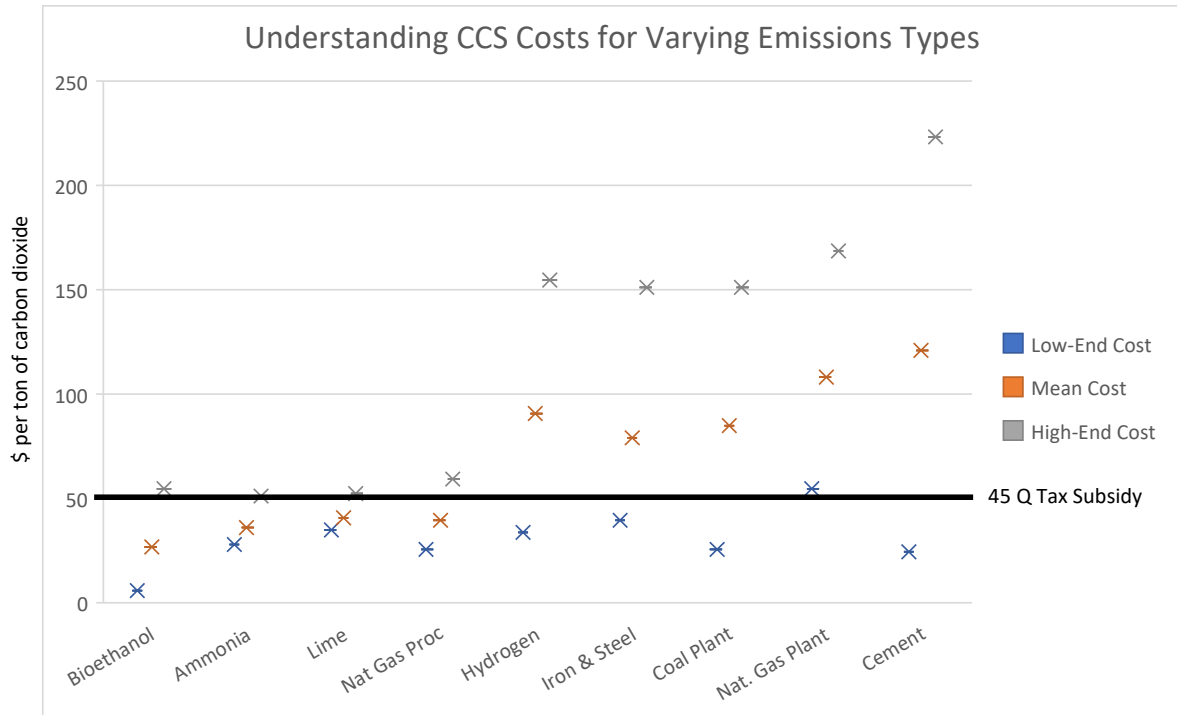


Figure 7: Range of CCS Costs by Varying Emissions Source
 Sources: Moch, Xue, & Holdren, 2022, Pilorgé, et al., 2020 & Schmelz, & Hochman, & Miller, 2020

Figure 8 depicts projected total CCS project costs if capture costs saw a 60% reduction over 10 years like the actual and projected capture costs for coal power plants as shown in work from Baylin-Stern & Berghout (2021). This figure gives readers a sense of what could happen which CCS costs in the next ten years and beyond while still accounting for the uncertainties such as annual emissions size, age of the facility, and fuel/electricity costs. One can see that if these cost reductions take place as seen in other renewable technologies, CCS becomes attractive even at the current tax credit environment of \$50 per ton of carbon dioxide sequestered and attractive across all cost scenarios and industries at an increased subsidy level of \$85 per ton of carbon dioxide sequestered.

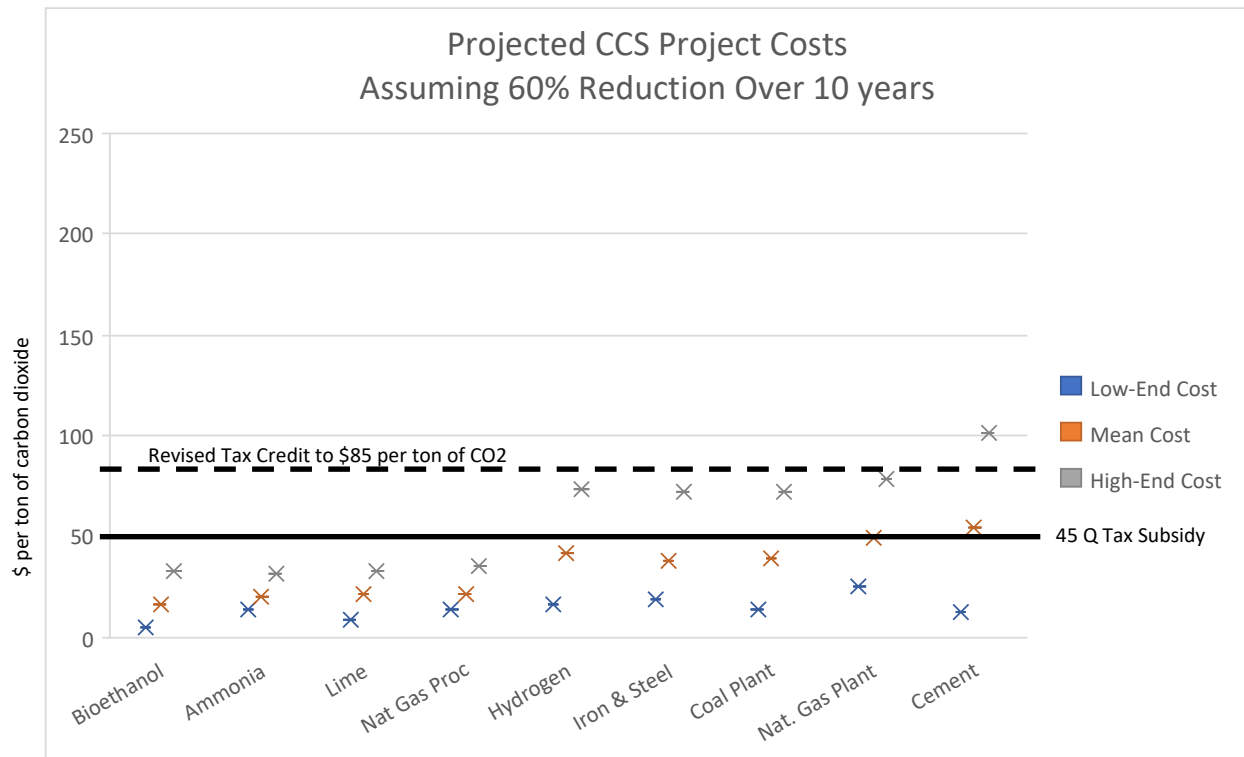


Figure 8: Projected Total CCS Costs, Accounting for 60% Capture Cost Reductions
 Sources: Moch, Xue, & Holdren, 2022, Pilorgé, et al., 2020, & Schmelz, Hochman, & Miller, 2020

6.1.2 Industrial Carbon Dioxide Emissions

The EPA’s Facility Level Information on Greenhouse Gases Tool (FLIGHT) does an excellent job of organizing and breaking down the nation’s industrial emissions on both a cumulative and yearly basis (EPA, 2021b). The EPA breaks the emissions into 9 broad categories: power plants, petroleum & natural gas systems, refineries, chemicals, other, minerals, waste, metals, and paper & pulp (EPA, 2021b). These categories can be broken down further into sub-categories which were utilized by Moch et. al. (2022) & Pilorgé et. al (2020) in their modeled capture cost analysis of various emission streams. Figure 9 highlights the 2020 annual industrial carbon dioxide emissions, broken out by category. The volume of emissions in millions of tons, followed by the percentage of total emissions, and finally the number of facilities is displayed for each category. Power plants make up most of the industrial emissions, accounting for 58%, followed by petroleum and natural gas systems at 12% (EPA, 2021b). The remaining sectors each account for smaller single-digit percentages of the total emissions for 2020 (EPA, 2021b).

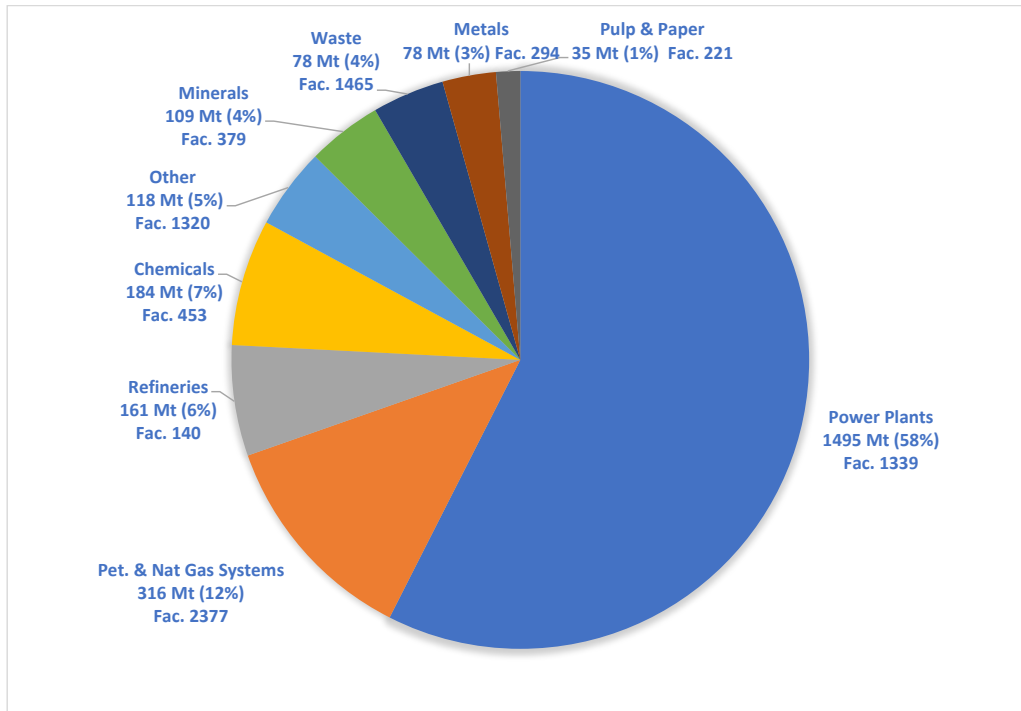


Figure 9: 2020 US Industrial Emissions by Sector
Source: EPA, 2021b

Table 3 below, highlights modeled capture costs for select industrial sector categories that were analyzed in Pilorgé et. al (2020) and Moch et. al. (2022), indicates the total annual emissions for the industrial sector, and highlights the percentage of total annual industrial emissions. This table aims to better understand how industrial emissions parse out with extensively modeled capture technologies. This in turn gives one the impression of how many annual emissions could be captured given the current state of modeled capture technology. For example, bioethanol has the cheapest modeled capture cost between \$0 and \$36 per ton of carbon dioxide, however in 2020 there were only 18 Mt of carbon dioxide emitted from bioethanol facilities accounting for less than 1% of total industrial emissions for 2020. On the opposite end, emissions from natural gas power plants were modeled to cost between \$54 and \$169 per ton of carbon dioxide which accounted for 25% of total annual carbon dioxide emissions.

One can now start to get a sense of where the largest opportunities lie regarding capturing emissions with modeled capture costs. In terms of the percentage of annual emissions, the largest opportunity exists within power plants. However, to account for the uncertainty of modeled capture costs, one would have to increase the tax subsidy to \$175 per ton of carbon dioxide sequestered to capture this

vast volume of annual emissions. It is logical to ask oneself, is this practical given current models and available capture technologies? In terms of power plants, while these account for most industrial emissions, it is important to note that for coal power plants there are alternative zero-carbon technologies such as wind, solar, or nuclear that could be implemented instead of utilizing CCS to capture these emissions. One could also argue that a complete transition from coal is preferred over utilizing CCS to sequester emissions from coal plants. Outside of power plants, capturing emissions from natural gas processing facilities offers the next largest opportunity of emissions that could be economically captured. Finally, while representing a small percentage of annual emissions (9.6%); ammonia, hydrogen, bioethanol, cement, lime, and iron & steel offer no viable and economic replacement industrial technologies, thus making CCS an economically viable technology that could be utilized to sequester industrial emissions from these processes.

*Table 3: Industrial Sub-Sector Capture Cost and Annual Emissions
Sources: Moch, Xue, & Holdren, 2022, Pilorgé, et al., 2020 & EPA, 2021b*

	Coal Power Plants	Natural Gas Power Plants	Natural Gas Processing	Ammonia	Hydrogen	Bioethanol	Cement	Lime	Iron & Steel
Capture Costs (\$/t CO ₂)	20-132	49-150	20-40	22-32	65-136	0-36	19-205	30-34	8-133
2020 Annual Emissions (Mt)	800	658	316	36	41	18	66	25	62
Percentage of Total Annual Emissions	30.7%	25.3%	12.1%	1.4%	1.6%	0.7%	2.5%	1.0%	2.4%

Figure 10 is a map from Pilorgé et. al (2020), showing the emissions locations, sized by annual emissions volume, and colored by emissions sub-sector type. The figure also highlights carbon dioxide pipelines, carbon dioxide injection wells (both Class II & Class VI), and major sedimentary basins. Industries with a blue star next to them denote industries that were analyzed within this capstone. One can clearly see, bioethanol emissions are not located near a major sedimentary basin but can be piped to either Williston Basin to the west or the Illinois Basin to the east. The map also shows that hydrogen,

ammonia, and cement emissions sources are vastly located within or near major US sedimentary basins, such as the Gulf Coast Basin and the Appalachian Basin, reinforcing their viability for use of CCS.

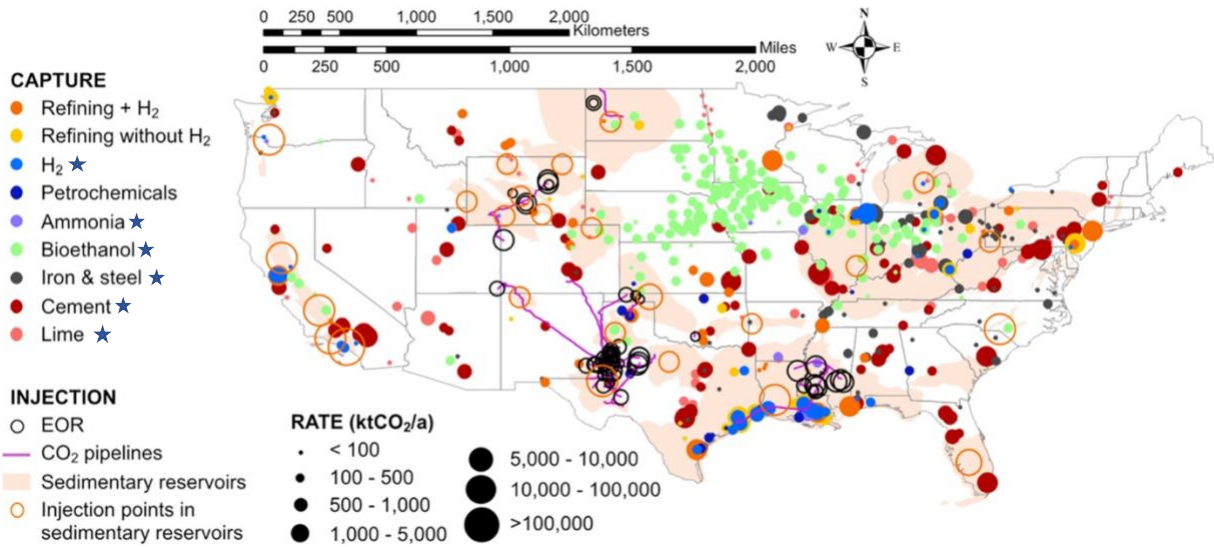


Figure 10: Geographic Distribution of Select CO₂ Capture Emission Sources
 Source: Figure from Pilorgé, et al., 2020

6.1.3 Overall Storage Potential Within the US

Table 4 shows the range of storage potential (by type and total) within the United States. This is a critical table as it shows an enormous storage potential for carbon dioxide emissions within the sedimentary basins of the United States, provided residual storage classes are included. The table also assumes an annual emissions volume of 2,600 Mt of carbon dioxide, the same annual volume of emissions from 2020, and then estimates the number of years the US could store that volume of emissions. As one can see, there is a tremendous amount of storage potential that in turn results in a millennium of time assuming comparable annual emissions volumes. This is an encouraging finding as the United States is not constrained by lack of space to store carbon dioxide provided this can be done securely and safely.

Table 4: Range of National CO2 Storage Potential (By Type & Total)
 Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b

Trapping Type	P5 Storage Resource (Mt)	Mean Storage Resource (Mt)	P95 Storage Resource (Mt)
Buoyant	19,000	44,000	110,000
Residual Class I	97,000	140,000	200,000
Residual Class II	2,100,000	2,700,000	3,300,000
Residual Class III	58,000	130,000	230,000
Total Storage Potential	2,300,000	3,000,000	3,700,000
# Of Years of Storage: Given 2020 Annual Emissions of ~2600	884 years	1153 years	1423 years

Figure 11 breaks down the national carbon dioxide storage potential by sedimentary basin within the United States. The Gulf Coast Basin stands out as the sedimentary basin that offers the most carbon dioxide storage potential within the United States, followed by the North Slope of Alaska, the South Florida Basin, the Illinois Basin, the Williston Basin, the Anadarko Basin, and the Permian Basin rounding out the top 7 (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b).

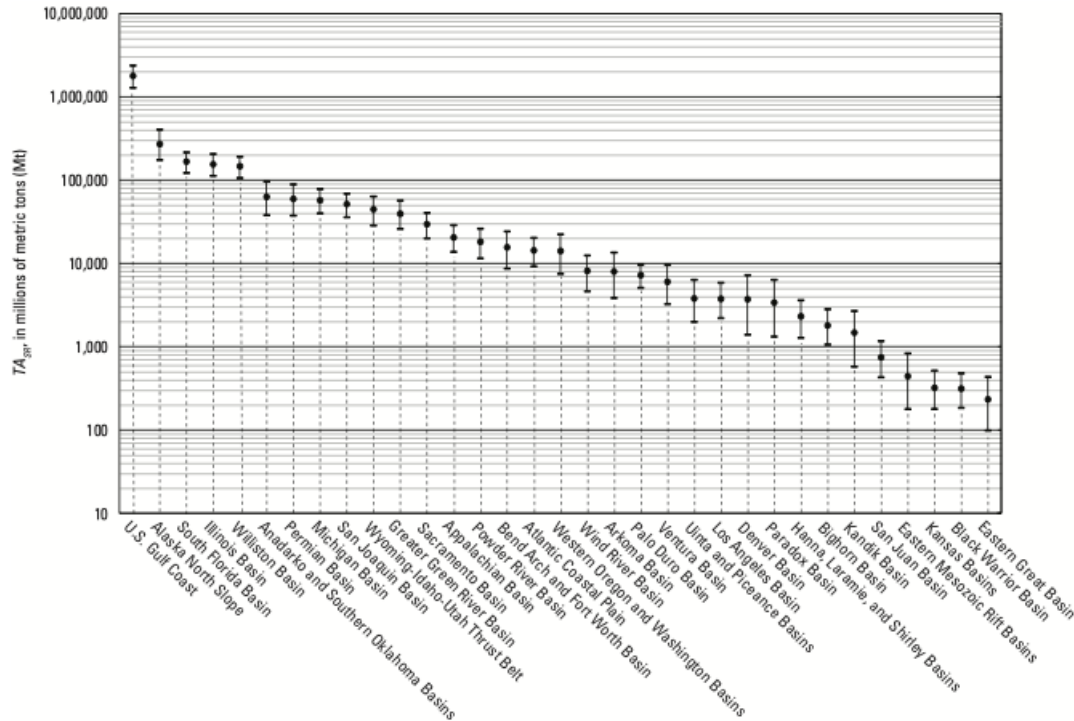


Figure 11: US CO2 Storage Potential Ranges by Sedimentary Basin
 Source: Figure from US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b

6.2 Case Studies Intro

In the following sections, the four case studies will be analyzed in the following manner:

- a brief introduction for each case study highlighting the basis of the emissions,
- a geographic overview of the various CCS components (emissions locations, pipelines, sequestration sites, and spatial location of prospective geologic formations),
- a discussion of the geologic parameters for the prospective sequestration formations,
- a presentation of the mean storage potential for the prospective sequestration formations,
- and an overview of a range component and total case study costs as well as a range of storage potential and storage years.

6.2.1 Case Study 1: Williston Basin Bioethanol

Case Study 1 evaluates the project costs and impacts of capturing bioethanol emissions in the Upper Midwest, transporting the emissions to the Williston Basin, where the emissions will be sequestered. This case study uses the facilities and general pipeline layout from the proposed Summit Carbon Solutions project (Summit Carbon Solutions, 2022). 2020 bioethanol emissions represented about 0.7% of the total industrial emissions (EPA, 2021b). The emissions stream from bioethanol plants represents the purest emissions in terms of carbon dioxide percentage. Bioethanol and carbon dioxide are created through fermentation of sucrose and is defined by the following chemical equation: $C_6H_{12}O_6 \rightarrow 2C_2H_5OH + 2CO_2$ (Pepin & Marzocco, 2015). Figure 12 highlights the emission sources that will be captured and transported from facilities in Iowa, Minnesota, Nebraska, North Dakota, and South Dakota. The colored areas on the map denote the prospective areas for sequestration. The 31 facilities highlighted below in Figure 12 produced approximately 3.2 million tons of carbon dioxide annually in 2020. The proposed project eventually calls for capturing up to 12 million tons of carbon dioxide per year which represents removing emissions from about 2.6 million ICE vehicles per year (Summit Carbon Solutions, 2022).

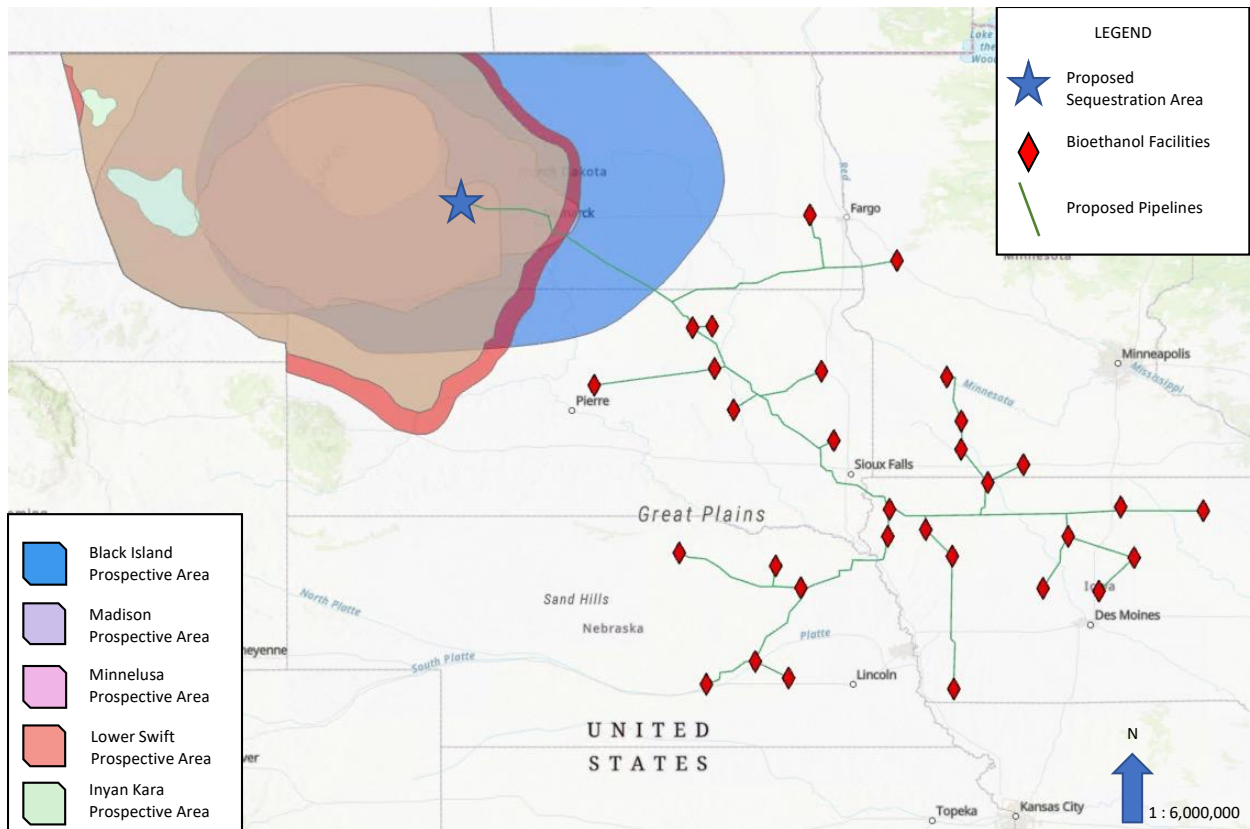


Figure 12: Case Study 1: Overview Map

Explanation: Williston Basin case study map depicting emissions facilities (red diamonds), proposed pipelines (green), the proposed sequestration area in purple, and the sequestration location (red star). Sources: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a, EPA, 2021b, & Summit Carbon Solutions, 2022

Table 5 highlights the various geologic parameters of the key formations evaluated by the USGS for the Williston Basin. Based off GIS mapping, the Black Island, Madison, Minnelusa, Lower Swift, and Inyan Kara were all perspective at the proposed sequestration site (blue star) (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a). The Madison Formation, highlighted in bold below was selected as the most favorable formation given its high mean gross thickness and high mean net porous interval.

*Table 5: Case Study 1: Geologic Parameters for Prospective Sequestration Formations
Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a*

Formation	Mean Depth (ft)	Mean Area (acres)	Mean Gross Thickness (ft)	Mean Net Porosity (ft)	Mean Available Space for Storage (%)	Mean Porosity (%)	Mean Perm (mD)
Black Island	5,000	40,554,000	400	240	70	12	10
Madison	6,400	33,043,000	1,800	300	70	10	4
Minnelusa	7,300	17,514,000	475	85	100	16	50
Lower Swift	5,500	46,694,000	350	70	30	17	100
Inyan Kara	5,000	44,326,000	250	130	25	18	100

Figure 13 highlights the mean total storage potential for each prospective geologic formation, with the corresponding P5 and P95 total storage potential for each prospective geologic formation contained in the appendix. From Figure 13, the Madison Formation stands out as the most favorable choice for sequestration due to its high total mean storage potential over about 18,000 Mt of carbon dioxide storage potential due to the high thickness and net porous estimations seen in Table 5. Class 2 trapping potential is seen as the primary trapping type within the Willison Basin and corresponds to permeability between 1 mD and 1D (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013b). Lastly, given that the Madison has a mean total accessible storage resource potential of 18,000 Mt of carbon dioxide, sequestering 3.2 million tons of carbon dioxide will be easily achieved in this formation.

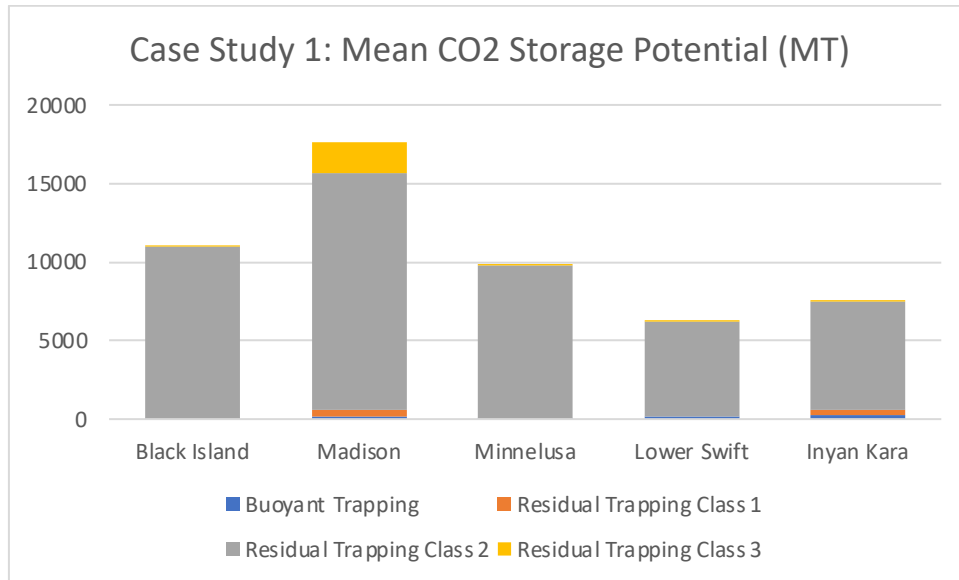


Figure 13: Case Study 1: Mean CO2 Storage Potential

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

Overall, Case Study 1, shows mixed economic metrics as shown below in Table 6. Given the purity of emissions stream from the production of ethanol through fermentation of sugar, the low-end modeled capture costs are estimated at zero Pilorgé, et al., (2020), but these modeled capture costs were shown to increase in work by Moch et. al. (2022). Transport costs, which include compression costs, account for a significant portion of total project costs, given the 3,000 km of planned pipeline for the case study. The low-end total project costs are below the current 45Q tax credit of \$50 per ton of carbon dioxide. As noted, before, ample storage space exists to sequester these emissions with the Madison offering up to 8,000 years of storage potential given the current emissions size of the case study and available storage space.

Table 6: Case Study 1: Range of Project Costs, Storage Potential, and Storage Years

Sources: Moch, Xue, & Holdren, 2022, Pilorgé, et al., 2020 & Schmelz, Hochman, & Miller, 2020

	Low-End	Mean	High-End
Capture Costs: (\$/t CO2)	0	18	36
Pipeline Costs: (\$/t CO2)	27.6	36.6	45.6
Sequestration Costs: (\$/t CO2)	3	6	15
Total Costs: (\$/t CO2)	30.6	60.60	96.60
	P5	Mean	P95
Madison Storage Potential (Mt)	10,000	18,000	28,000
Madison Storage Potential years (Annual emissions 3.2 Mt/Storage Potential)	3,125 years	5,625 years	8,000 years

6.2.2 Case Study 2: Gulf Coast Ammonia & Hydrogen

Case Study 2 captures ammonia and hydrogen emissions within the Louisiana Gulf Coast. While no formal project has been proposed, Denbury Resources has announced plans to collect industrial emissions from unnamed sources within the Louisiana Industrial Corridor which is near New Orleans (Denbury Resources, 2022). Given the available facilities, it is reasonable to assume Denbury is attempting to capture emissions from hydrogen and ammonia plants within the industrial corridor. The red diamonds depicted below in Figure 14, are all the hydrogen and ammonia facilities within the Louisiana Industrial Corridor. The sequestration site, highlighted by the blue star, occurs at an area where both Lower Miocene Sands are prospective for sequestration. This is one reason the sequestration site was located here, as having two formation options for sequestration are clearly better than one. Overall, this case study aims to sequester up to about 15.4 million tons of carbon dioxide per year from 3 ammonia facilities and 10 hydrogen facilities. For this case study, capture costs were calculated using a weighted average based upon the number the facilities and appropriate modeled capture costs.

Before diving into additional details regarding this case study, it is important to understand how these emissions are produced. Hydrogen produced from steam-methane reforming is defined by the following chemical reaction: $\text{CH}_4 + \text{H}_2\text{O} (+ \text{heat}) \rightarrow \text{CO} + 3\text{H}_2$ from there the products undergo a water shift reaction defined by $\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$ and small amount of heat (DOE, 2022). To make ammonia from natural gas, the same steps to create hydrogen from natural gas are followed thus creating carbon dioxide as a by-product that can be captured. To complete the production of ammonia, any remaining small amounts of carbon monoxide and carbon dioxide are removed because of catalytic methanation, and it is catalytically reacted with nitrogen to form anhydrous liquid ammonia (Clark, 2020).

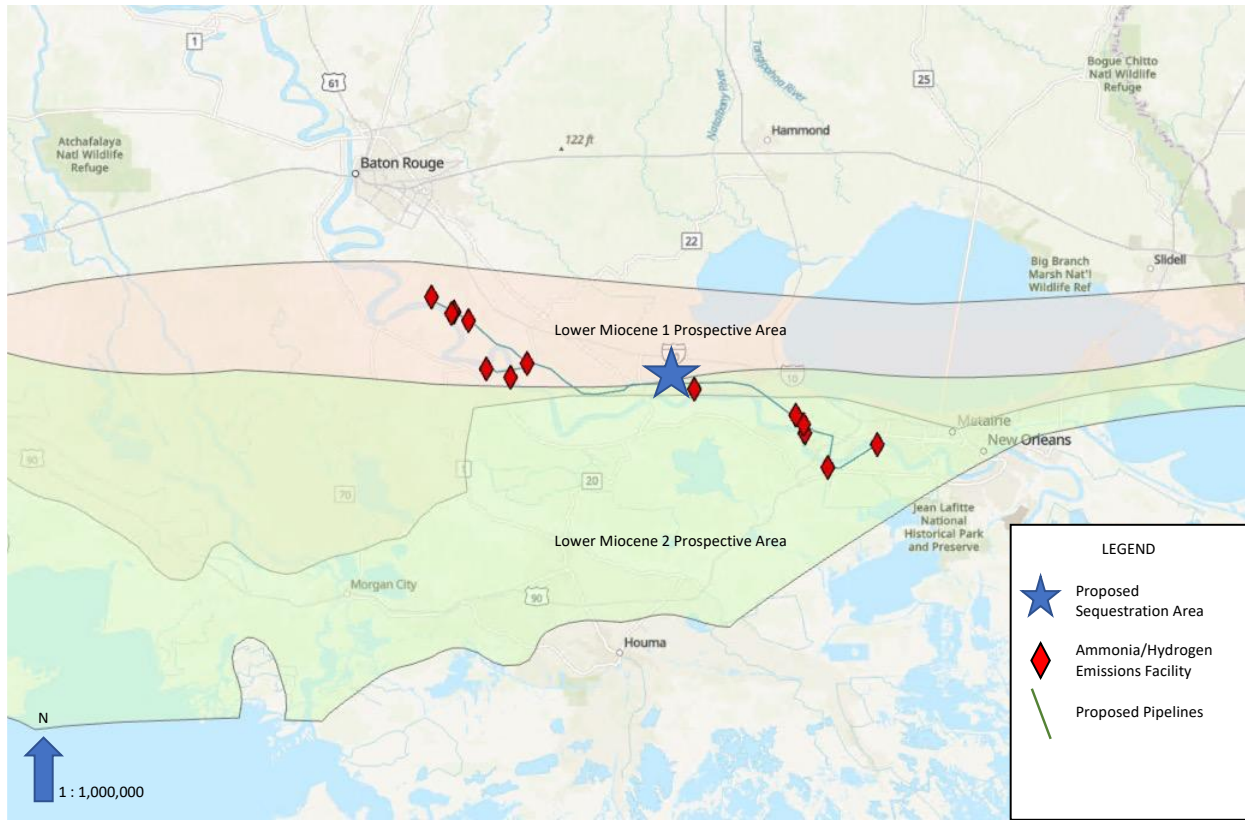


Figure 14: Case Study 2: Overview Map

Explanation: Depicts facilities, proposed pipelines, perspective sequestration formations, perspective sequestration site, and additional emissions to be captured in Texas. Sources: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a & EPA, 2021b

Table 7 highlights the various geologic parameters of the prospective formations evaluated by the USGS for the area within and near the Louisiana Industrial Corridor. Based off GIS mapping, the Lower Miocene 1 and Lower Miocene 2 sands were prospective at the proposed sequestration site (blue star) (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a). Based off the geologic parameters presented, both Lower Miocene sands have favorable thickness, favorable net porous intervals, with high mean porosities and high mean permeabilities. Because both formations are prospective at the sequestration site and offer similar and favorable geologic parameters, thus both formations would be candidates for sequestration of carbon dioxide emissions.

Table 7: Case Study 2: Geologic Parameters for Prospective Sequestration Formations
 Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

Formation	Mean Depth (ft)	Mean Area (acres)	Mean Gross Thickness (ft)	Mean Net Porosity (ft)	Mean Available Space for Storage (%)	Mean Porosity (%)	Mean Perm (mD)
Lower Miocene 1	8,000	8,432,000	1,500	600	100	28	500
Lower Miocene 2	8,000	9,924,000	1,600	550	95	28	500

Figure 15 below depicts the mean carbon dioxide storage potential for the Lower Miocene 1 and Lower Miocene 2 sands. As stated above both formations have similar geologic parameters and as a result both sands have similar storage potential both in terms of total capacity (56,000 Mt for the Lower Miocene 1 & 58,000 Mt for Lower Miocene 2) but also similar breakdowns for Class 1 and Class 2 residual trapping storage potential. This reinforces the above observation that both formations could be suitable at the proposed sequestration site. See appendix for the P5 and P95 storage potential for these formations.

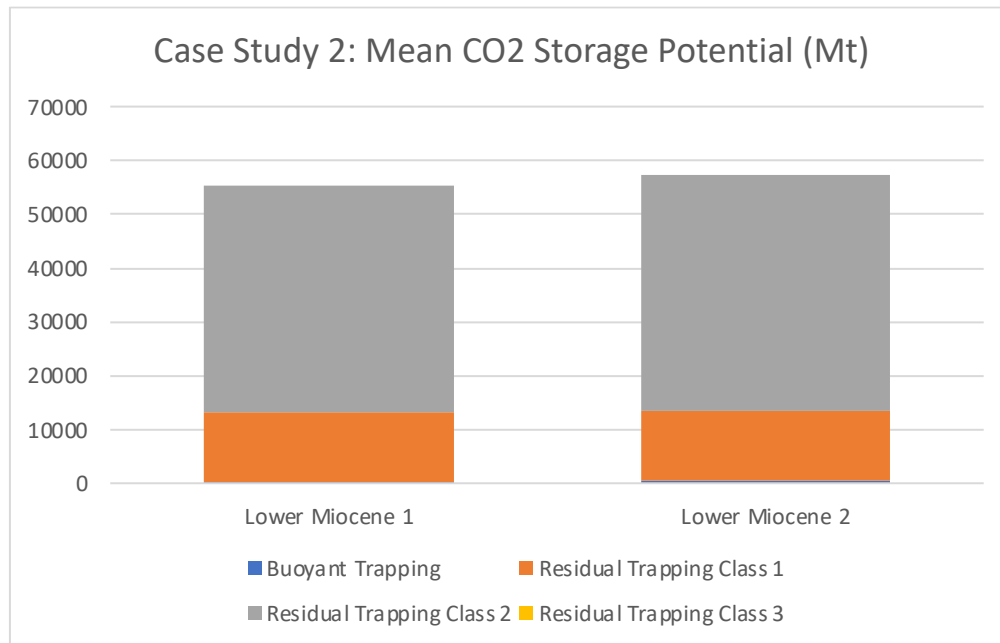


Figure 15: Case Study 2: Mean CO2 Storage Potential
 Sources: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

Overall, Case Study 2 has mixed projects costs as shown in Table 8, the low-end cost scenario is economically viable, but again due to uncertainty associated with modeled capture costs, the mean and high-end scenarios are currently uneconomic given the current 45Q tax credit. The increase in capture

costs, compared to Case Study 1, are offset by the reduced pipeline transport costs given the relative proximity these facilities have to the sequestration site. In terms of storage potential years, there is plenty of storage potential, upwards of over 5,500 years for this case study. The favorable geologic parameters and storage potential yield a high number of potential storage years. Furthermore, Figure 16 highlights two comparable areas near Houston, Texas and Beaumont, Texas where emissions from hydrogen facilities could be captured and sequestered in the Lower Miocene 1 or Lower Miocene 2 sands.

Table 8: Case Study 2: Range of Project Costs, Storage Potential, and Storage Years
Sources: Moch, Xue, & Holdren, 2022, Pilorge, et al., 2020 & Schmelz, Hochman, & Miller, 2020

	Low-End	Mean	High-End
Capture Costs: (\$/t CO2)	26.6	69.4	112.1
Pipeline Costs: (\$/t CO2)	1.00	1.35	1.70
Sequestration Costs: (\$/t CO2)	3	6	15
Total Costs: (\$/t CO2)	30.60	76.75	128.80
	P5	Mean	P95
Muddy 1 Storage Potential (Mt)	33,000	56,000	85,000
Muddy 1 Storage Years (Annual emissions 15.4 Mt /Storage Potential)	2,142 years	3,636 years	5,519 years
Muddy 2 Storage Potential (Mt)	36,000	58,000	85,000
Muddy 2 Storage Years (Annual emissions 15.4 Mt /Storage Potential)	2,142 years	3,766 years	5,519 years



Figure 16: Additional CCS Opportunities in the Gulf Coast
Source: EPA, 2021b & US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

6.2.3 Case Study 3a: DJ Basin Coal Power Plants

Case Study 3a evaluates the project costs and impacts of capturing emissions from pulverized coal fired power plants in the eastern half of Colorado within the DJ Basin. There is no real-world analogue project that ties back to this case study, however, it is an important case study to consider as pulverized coal power plants nationally account for 800 million tons of carbon dioxide emissions annually in 2020. This represents 54% of emissions from the power plants in 2020 and 31% of all US carbon dioxide industrial annual emissions in 2020 (EPA, 2021b). Specifically, to Colorado, coal power plants account for 53% of the state's total 2020 carbon dioxide emissions (EPA, 2021b). The combustion of coal is defined by the following equations: $C + O_2 \rightarrow CO_2$, if there is insufficient oxygen carbon monoxide is formed ($2C + O_2 \rightarrow 2CO$) and if sulfur is present sulfur dioxide is produced ($S + O_2 \rightarrow SO_2$) (Electrical 4 U, 2022). Figure 17 highlights the emissions sources that will be captured and transported from facilities in southeastern Wyoming and east-central Colorado. These emissions are transported via pipeline over shorter distances to three sequestration areas, one in southeastern Wyoming, another in south-central Colorado, and third sequestration site would be located on-site or near to one of the facilities in north-central Colorado. Three sequestration sites were proposed to cut down on transport costs given the large geographic area and that several formations are prospective for sequestration. Overall, this case study aims to sequester up to 20.5 million tons of carbon dioxide per year captured from 7 pulverized coal fired power plants.

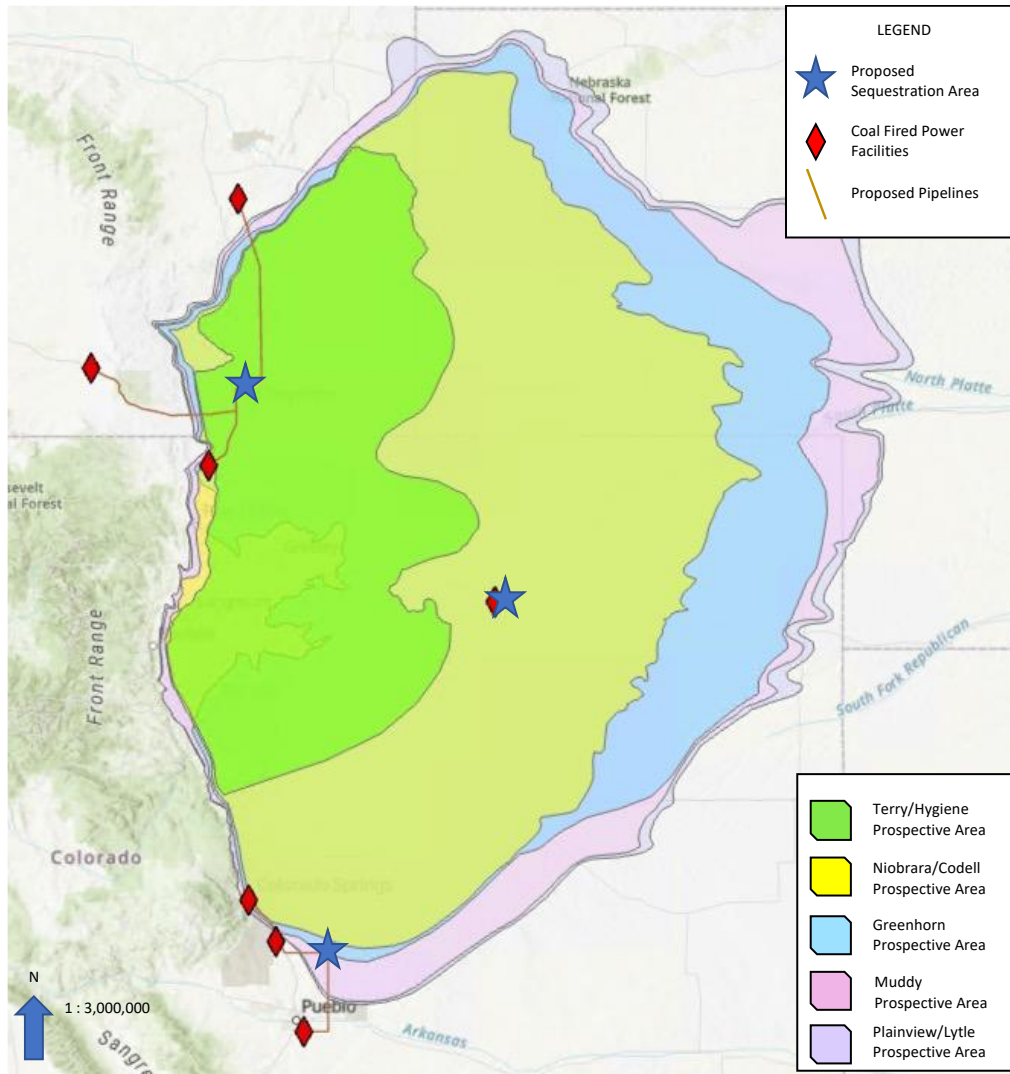


Figure 17: Case Study 3a: Overview Map

Explanation: shows facilities in blue, pipelines in brown, favorable formations for sequestration in the colored polygons, and proposed sequestration sites by red stars. Sources: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a & EPA, 2021b

Table 9 highlights the various geologic parameters of the prospective formations evaluated by the USGS for the DJ Basin of southeastern Wyoming and east-central Colorado. Based off GIS mapping, the Terry/Hygiene, Niobrara/Codell, Greenhorn, Muddy, and Plainview/Lytle formations of the Cretaceous are prospective for sequestration while the deeper Paleozoic formations more commonly associated with the Anadarko Basin were not evaluated in this area (US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a). Based off the geologic parameters presented, the Muddy Formation has adequate thickness and noticeably higher porosity and permeability. Also, important to

consider here is the mean available space for storage which is defined by the formation water salinity. Carbon dioxide emissions are sequestered in saline formations that must meet a certain salinity, however due to these formations outcropping nearby (in the Front Range), formation water can be fresh near the outcrop and becomes progressively more saline as one moves to the east.

*Table 9: Case Study 3a: Geologic Parameters for Prospective Sequestration Formations
Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a*

Formation	Mean Depth (ft)	Mean Area (acres)	Mean Gross Thickness (ft)	Mean Net Porosity (ft)	Net to Gross	Mean Available Space for Storage (%)	Mean Porosity (%)	Mean Perm (mD)
Terry/Hygiene	4,500	6,400,000	500	35	7%	30	8	1
Niobrara/Codell	5,000	17,039,000	350	20	6%	30	10	0.1
Greenhorn	5,730	20,024,000	125	13	10%	30	9	0.1
Muddy	5,500	23,500,000	200	100	50%	30	18	100
Plainview/Lytle	7,000	24,400,000	140	100	71%	30	10	0.1

Figure 18 depicts the mean carbon dioxide storage potential for the prospective formations within the DJ Basin. The Muddy Formation rises above the other formations in terms of total storage potential with most storage potential coming from residual class 2 trapping. Given 20 million tons of carbon dioxide emissions per year, that allows for up to 258 years of sequestration before the formation reaches capacity, as shown in Table 10. But one must also consider the feasibility given the large geographic area of the Muddy, low overall storage potential, and combined with the high yearly emissions of 20 million tons of carbon dioxide. It is reasonable to think that individual sequestration sites may not be capable of sequestering this volume of emissions. Thus, more detailed site characterizations will be needed to confirm the available pore space for sequestration versus the desired emissions to be sequestered. In other words, more than three sequestration sites may be needed for this case study. Figures for P5 and P95 storage potential for these formations can be found in the appendix.

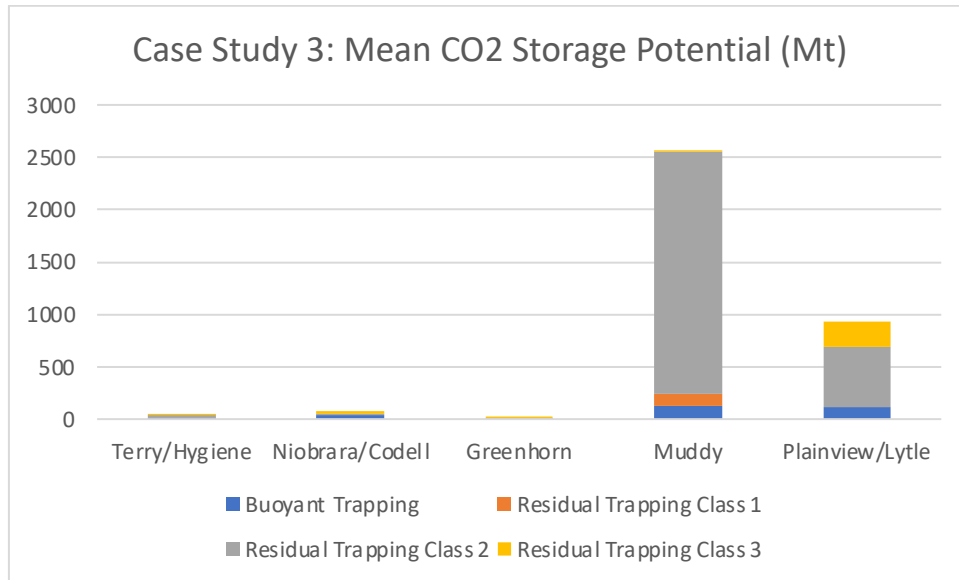


Figure 18: Case Study 3A: Mean CO2 Storage Potential
 Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

Overall, like the other two case studies as seen in Table 10, Case Study 3A has favorable low-end total project costs when compared to the current \$50 per ton of carbon dioxide tax credit. However, also like the other two case studies, the mean and high-end modeled capture costs alone make implementing such a project economically unfavorable. Given that these emissions account for a substantial chunk of 2020 annual carbon dioxide emissions, as noted earlier, one of three things must occur: either the modeled cost to capture these emissions must come down because of an evolution in the capture technology, or the tax subsidy must be increased up to around \$150 per ton of carbon dioxide, or coal power plants must be phased out completely. In terms of storage potential, the Muddy offers a more than adequate amount of storage years but is less than the other two case studies.

Table 10: Case Study 3A: Range of Project Costs, Storage Potential, and Storage Years
 Sources: Moch, Xue, & Holdren, 2022, Pilorge, et al., 2020 & Schmelz, Hochman, & Miller, 2020

	Low-End	Mean	High-End
Capture Costs: (\$/t CO2)	20	76	132
Pipeline Costs: (\$/t CO2)	2.95	3.90	4.90
Sequestration Costs: (\$/t CO2)	3	6	15
Total Costs: (\$/t CO2)	25.95	85.90	151.90
	P5	Mean	P95
Muddy Storage Potential (Mt)	880	2,600	5,300
Storage Years (Annual Emissions: 20.5 Mt CO2/Storage Potential)	42 years	126 years	258 years

6.2.4 Case Study 3B: DJ Basin Natural Gas

Case Study 3B swaps the coal power plants for natural gas fired power plants and reevaluates the project costs. This case study aims to evaluate the economics of utilizing CCS at natural gas fired power plants. As a result, no real-world analogue project ties back to this case study. However, to put the case study in greater context, natural gas fired power plants nationally account for 658 million tons of carbon dioxide emissions annually in 2020. This represents 44% of annual emissions from power plants in 2020 and about 25% of all US carbon dioxide industrial emissions in 2020 (EPA, 2021b). Since natural gas-fired power plants generate 40% of carbon dioxide emissions compared to coal-fired power plants, the revised annual emissions that this case study aims to sequester are 8.2 million tons of carbon dioxide (EPA, 2019). Table 11 below replaces the range of capture costs with costs modeled for natural gas fired power plants. These modeled capture costs are noticeably higher than those modeled capture costs associated with coal fired power plants, thus negatively impacting the overall project economics. In fact, from below, all project costs are above the current \$50 per ton of carbon dioxide tax credit, with the mean and high-end costs being well above \$100 per ton of carbon dioxide. While natural gas fired power plants may emit less carbon dioxide than coal fired power plants, implementing CCS for natural gas fired power plants remains highly economically challenging. A significant increase in the tax subsidy would be needed, significant evolution and cost reductions for capture technology would be needed, or substantial refinement to the uncertainty surrounding modeled capture costs for natural gas fired power plants is needed. Finally, given the reduced volume of annual emissions but using the same range of storage potential, storage years for emissions from natural gas fired power plants increased when compared back to Case Study 3A but are still noticeably less than Case Studies 1 and 2.

Table 11: Case Study 3B: Range of Project Costs, Storage Potential, and Storage Years
Sources: Moch, Xue, & Holdren, 2022, Pilorge, et al., 2020 & Schmelz, Hochman, & Miller, 2020

	Low-End	Mean	High-End
Capture Costs: (\$/t CO2)	49	99.5	150
Pipeline Costs: (\$/t CO2)	2.95	3.90	4.90
Sequestration Costs: (\$/t CO2)	3	6	15
Total Costs: (\$/t CO2)	54.95	109.40	169.90
	P5	Mean	P95
Muddy Storage Potential (Mt)	880	2,600	5,300
Storage Years (Annual Emissions: ~8.2 Mt CO2/Storage Potential)	107 years	317 years	646 years

6.2.5 Case Studies Summary & Proposed Policy Adjustments

As seen in Table 12, Case Study 1, focusing on bioethanol emissions in the Midwest, has the most favorable mean project costs of \$61 per ton of carbon dioxide, followed by Case Study 2 focusing ammonia & hydrogen emissions within the Gulf Coast at \$77 per ton of carbon dioxide, followed by Case Study 3A, focusing on coal power plant emissions in the DJ Basin at \$86 per ton of carbon dioxide, and finally Case Study 3B, focusing on natural gas fired power plants in the DJ Basin at \$109.42 per ton of carbon dioxide. None of the mean project costs are modeled to be below the current 45Q tax credit of \$50 per ton of carbon dioxide. However, increasing the tax credit to \$85 per ton of carbon dioxide as proposed by Congress and highlighted in work by McMahan (2021) would make all the case studies except natural gas fired power plants in the DJ Basin economic on a mean project cost basis.

Table 12: Summary of Case Studies: Mean Costs, Storage Potential, & Storage Years
Sources: EPA, 2021b, Moch, Xue, & Holdren, 2022, Pilorge, et al., 2020, & Schmelz, Hochman, & Miller, 2020

	Mean Capture Costs (\$/t CO2)	Mean Transport Costs (\$/t CO2)	Mean Sequestration Costs (\$/t CO2)	Total Mean CCS Costs (\$/t CO2)	Annual CO2 Sequestered (t)	Mean Storage Potential (Mt)	Mean Storage Years
Case Study 1: Bioethanol in the Williston Basin	18	36.6	6	\$60.60	3,202,409	18,000	5,625
Case Study 2: Ammonia/Hydrogen in the Gulf Coast	68.4	1.35	6	\$76.75	15,407,049	56,000 58,000	3,636 3,766
Case Study 3a: Coal Power Plants in the DJ Basin	76	3.92	6	\$85.92	20,567,188	2,600	126
Case Study 3b: Nat. Gas Power Plants in the DJ Basin	99.50	3.92	6	\$109.42	~8,200,000	2,600	317

The subsequent table, Table 13, highlights the low-end, mean, and high-end total project costs for the four case studies. On a low-end basis, three of the four case studies are economic, except natural gas-fired power plants. Overall, given that the mean and high-end modeled costs are higher than the current

tax credit, it is reasonable to conclude that this is a barrier to implementing this technology on a large-scale.

Table 13: Low-end, Mean, & High-end Project Costs for Case Studies
Sources: Moch, Xue, & Holdren, 2022, Pilorge, et al., 2020 & Schmelz, Hochman, & Miller, 2020

	Low-End (\$/t CO₂)	Mean (\$/t CO₂)	High-End (\$/t CO₂)
Case Study 1: Bioethanol in the Williston Basin	30.60	60.60	96.60
Case Study 2: Ammonia/Hydrogen in the Gulf Coast	30.60	76.75	128.80
Case Study 3a: Coal Power Plants in the DJ Basin	25.95	85.90	151.90
Case Study 3b: Nat. Gas Power Plants in the DJ Basin	54.95	109.40	169.90

Given the high degree of uncertainty surrounding modeled capture costs, one could consider policy instruments that expand funding for the research and development of more cost-effective means to capture carbon dioxide emissions from select industrial sources and power plants. Such expansion in funding would fuel additional implementation of the CCS, driving down costs in the long term, as already seen within power plants in work from Baylin-Stern & Berghout (2021) and as seen in other renewable technologies.

7. Discussion & Conclusions

After establishing the technical and economic fundamentals of CCS through a detailed literature review and through the analysis of varying industrial emissions, storage potential, and project costs estimation; the primary takeaways from the capstone project are:

- CCS is a technically proven and viable process to mitigate carbon dioxide emissions from large stationary sources.
- The United States has an abundant amount of subsurface pore space available within the sedimentary basins in the continental United States.
- Economics are a major hurdle.

- Carbon capture costs are the costliest component of CCS, accounting for most of the estimated project costs.
- Capture costs also account for the largest degree of uncertainty among project costs and can be attributed to annual emissions volume, life span of the emitting facility, and fuel/electric costs of the facility.
- The uncertainty surrounding capture costs varies in size among different industrial sectors. Modeled capture costs for bioethanol, ammonia, lime, and natural gas processing facilities have lower uncertainty than those associated with hydrogen, iron & steel, coal-fired power plants, and natural gas-fired power plants.
- If similar capture cost reductions are seen across other industrial sectors over the next 10 years as was seen in the work by Baylin-Stern & Berghout (2021), CCS becomes more economically attractive at the current tax credit level of \$50 per ton of carbon dioxide and even more attractive if the subsidy was increased to \$85 per ton of carbon dioxide.
- Based on research and project cost modeling, the current 45Q tax credit of \$50 per ton carbon dioxide sequestered does not offer enough financial incentive nor cover the anticipated project cost uncertainty for those who want to utilize CCS.
 - As mentioned above, increasing the subsidy in the near-term from \$50 per ton of carbon dioxide to \$85 per ton of carbon dioxide would spur additional investment of the technology which would result in additional downward pressure on all costs but specifically capture costs in the long run. This process would be like processes already implemented for solar PV and onshore wind, which saw dramatic decreases in costs as well.

Given the high degree of uncertainty surrounding project costs, more research, development, and demonstration of capture technologies and processes for CCS is needed before this technology can be utilized to its fullest potential.

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9. Annex

9.1 Overview of Administrative Aspects of Geologic Carbon Sequestration

In the interest of brevity, this section was added to the annex to provide readers a brief overview of the administrative aspects of CCS. A brief overview of the technical information needed for the permitting process through the EPA will be presented before discussing an overview of the process states can follow in achieving permitting primacy for Class VI injection wells.

9.1.1 Overview of current administrative policy

The permitting process for Class VI injection wells is highly complex. This complexity is highlighted by the fact that the EPA documents governing the permitting of a Class VI injection well are composed of 13 guidance documents, containing over 1,200 pages plus another 14 documents highlighting examples of requested inputs, adding another 200 pages (Hendrickson & Beard, 2021). Necessary components that must be submitted for the permitting of a Class VI injection well are: geologic maps that highlight the regional geology, the presence of faults and fractures, and assess the injection and confining zone facies; geologic cross-sections; a petrographical assessment; a petrophysical assessment; a geomechanical analysis; a geochemical analysis; and an overview of the hydrogeologic properties of the storage site (EPA, 2013). These components are then compiled into a 3D earth model where injected carbon dioxide is modeled. While not required, 2D or 3D seismic data acquisition and processing does add additional cost and time to the project, but also greatly enhances the supporting data associated with the 3D earth model. The EPA has created a guidance document outlining the basic requirements for obtaining, processing, and incorporating seismic data into a 3D earth model (EPA, 2013). The goal of this data collection and modeling process is to ensure that the facility is appropriately sited, constructed, tested, monitored, and funded (EPA, 2021a). In cases where the necessary information is not available, test wells must be drilled, where the missing information is obtained, thus adding additional cost and time to the permitting process (Hendrickson & Beard, 2021).

9.1.2 State Permitting Primacy

For all underground injection wells (Class I through Class VI), an option is available for states to apply for primacy via an administrative process. Such a process ensures that states have equivalent regulatory programs in place that will regulate the function, construction, operation, and closure of certain types of injections wells, including Class VI injection wells (Carbon Capture Coalition, 2021). Currently, 34 states have primacy over at least one type of injection well, while only two states (North Dakota and Wyoming) have been granted primacy by the EPA for Class VI injection wells, with Arizona, Louisiana, Texas, and West Virginia having initiated the process for primacy while Kansas, Montana, New Mexico, and Oklahoma have expressed interest in pursuing the process (Carbon Capture Coalition, 2021). Scaling up capacity for EPA permitting of Class VI injection wells and the capacity to review Class VI primacy applications will be critical in contributing to the successful scale up of CCS (Carbon Capture Coalition, 2021). The process took North Dakota five years to be granted primacy by the EPA for Class VI injection wells while that time was significantly reduced for Wyoming to nine months (Hendrickson & Beard, 2021). In states that lack primacy, additional permits at the state-level may be required thus adding another regulatory element, resulting in additional cost and time (Hendrickson & Beard, 2021).

9.2 Analogue Technologies & Current Use

In this section, similar technologies to CCS will be highlighted and discussed. Enhanced oil recovery, or EOR, could be considered a precursor technology process to the permanent geologic sequestration of carbon dioxide. While underground storage of natural gas utilizes similar principles and processes as CCS. Finally, a brief overview of the current Class VI injection wells will be presented.

9.2.1 Enhanced Oil Recovery & Carbon Sequestration

One technology that is similar to CCS is enhanced oil recovery. Enhanced oil recovery, or EOR, has been around since the early 1970's, the oil and natural gas industry has used carbon dioxide to flood partially depleted oil and gas reservoirs as an enhanced oil recovery (EOR) mechanism (Roberts, 2019). Since conventionally produced oil reservoirs have a recovery factor of about 10%, using EOR increases

this recovery factor to between 30 and 40 percent, thus extending the life and ultimate recovery from a particular field/formation (Roberts, 2019). 85% of carbon dioxide used in the EOR process comes from terrestrial sources, not anthropogenic, but it is trapped using residual trapping and it has been estimated that between 90% and 95% of carbon dioxide pumped into the ground for EOR, remains in the ground (Roberts, 2019). There are about 35,000 Class II injection wells, however, a vast majority of these injection wells are for brine water and only a small percentage are used as carbon dioxide injection wells for EOR (Congressional Research Service, 2020). EOR is not an ideal use of geologic carbon sequestration technology as the oil and gas produced from EOR obviously creates more carbon dioxide emissions. With that said, one cannot disregard the process parallels between EOR and the permanent sequestration of carbon dioxide emissions.

9.2.2 Carbon Capture & Connection to Natural Gas Storage

Another technology that involves pumping large quantities of a substance into the ground is natural gas storage. The United States stores natural gas underground (either in salt caverns or in porous & permeability sedimentary formations) starting in the Spring months through early Fall, then in the cooler months the stored natural gas is pulled as demand warrants for consumption (EIA, 2021). The United States has 387 active storage fields, which can store up to 4 BCF of natural gas (EIA, 2021). Using a conversion factor of 0.0551 tons of carbon dioxide per 1,000 cubic feet of natural gas, 4 BCF of natural gas is equivalent to 220,400 tons of carbon dioxide (EPA, 2022b). This capacity volume is significantly smaller than the expected volumes of carbon dioxide that are available to be sequestered on a yearly basis from industrial sources and power plants. So, while there are similarities to pumping natural gas into the ground for temporary storage, the volumes involved in natural gas storage are significantly smaller than those anticipated with CCS.

9.2.3 Current Class VI Projects

There are currently two Class VI injection wells in operation at the Archer Daniels Midland Facility, capable of sequestering a combined total volume of 7 million tons of carbon dioxide over their

lifespans, and both of which are in the Illinois Basin of central Illinois (EPA, 2022a). In addition, there are 14 proposed/pending applications for Class VI injection wells broken up by state as follows: 7 in Louisiana, 4 in California, 1 in Ohio, and 1 in Indiana (EPA, 2022a). The state of North Dakota, which achieved primacy for permitting Class VI injection wells already has permitted one facility with three additional facilities pending approval (North Dakota Oil & Gas Division, n.d.). These numbers are constantly in a state of flux, earlier in January of 2022 during the initial research for this capstone, there were only 6 Class VI pending permits, so in the span of 4 months this number has more than doubled. This clearly shows, CCS is at a critical junction where demand to implement the technology is increasing. Proper resources must be allocated at the Federal level to ensure these permits are assessed accurately and in a timely fashion while at the same time adequate resources exist at the Federal level to ensure state's wishing to pursue primacy for Class VI injection wells can so quickly and effectively.

10. Appendix

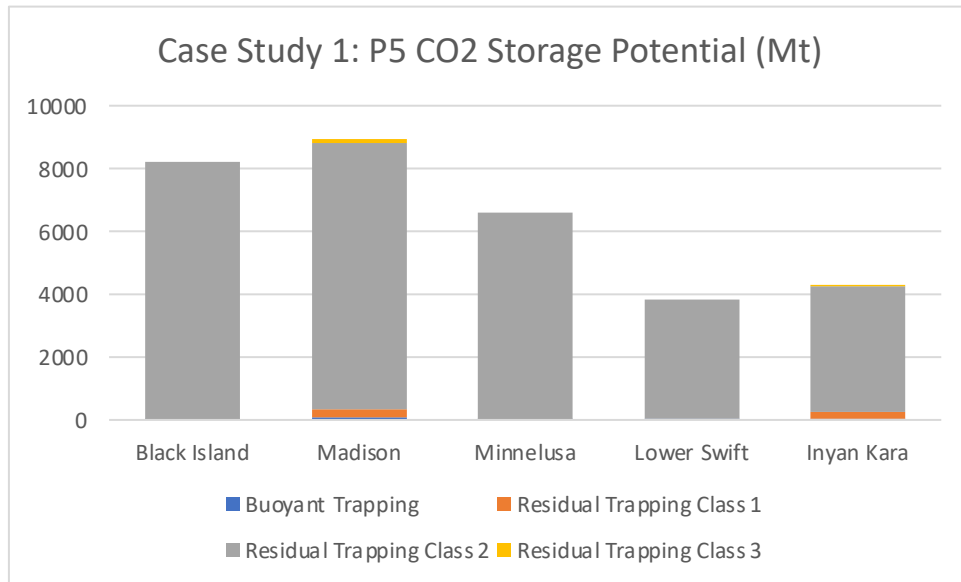


Figure 19: Case Study 1: P5 CO2 Storage Potential (Mt)

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

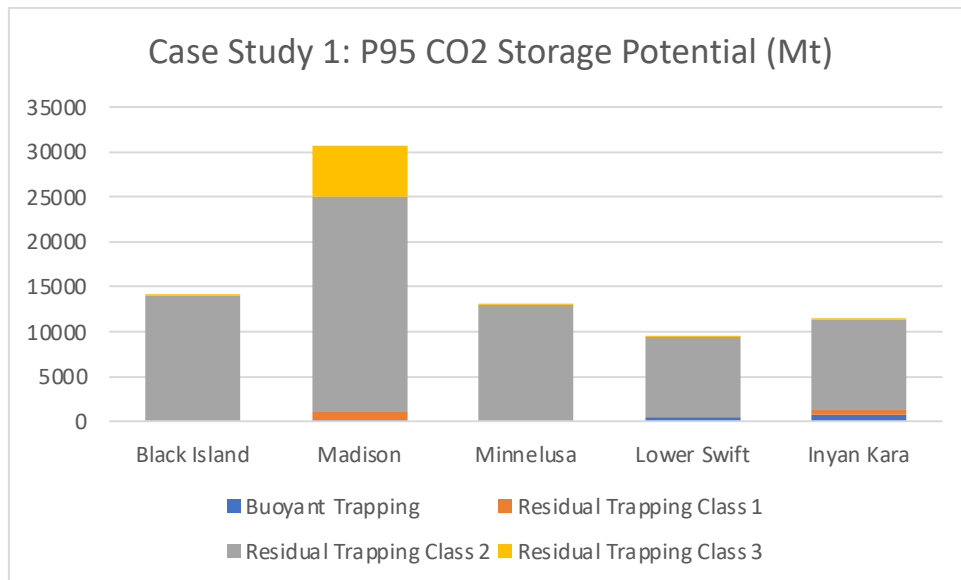


Figure 20: Case Study 1: P95 Storage Potential (Mt)

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

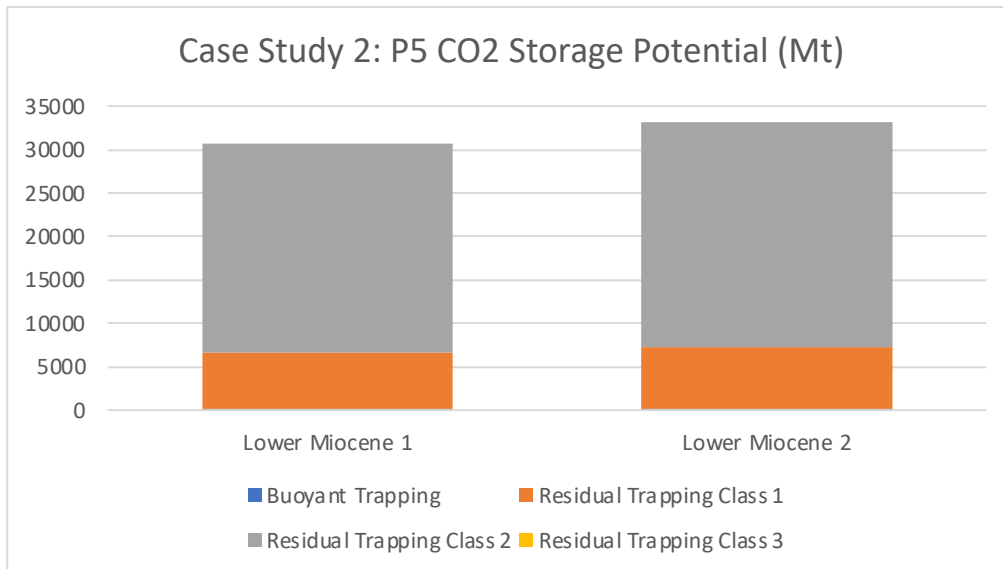


Figure 21: Case Study 2: P5 Storage Potential (Mt)

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

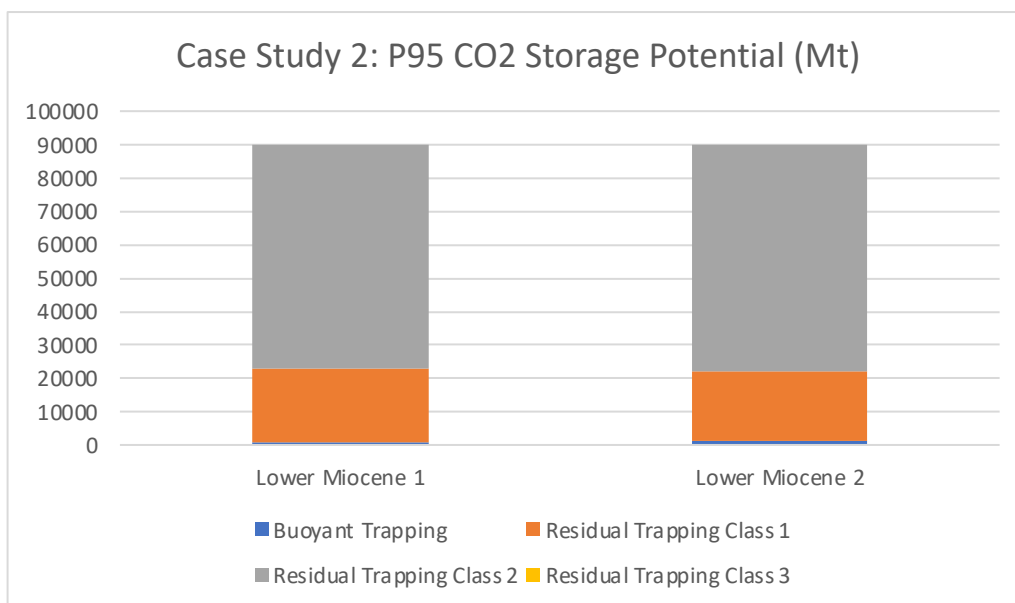


Figure 22: Case Study 2: P95 Storage Potential

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

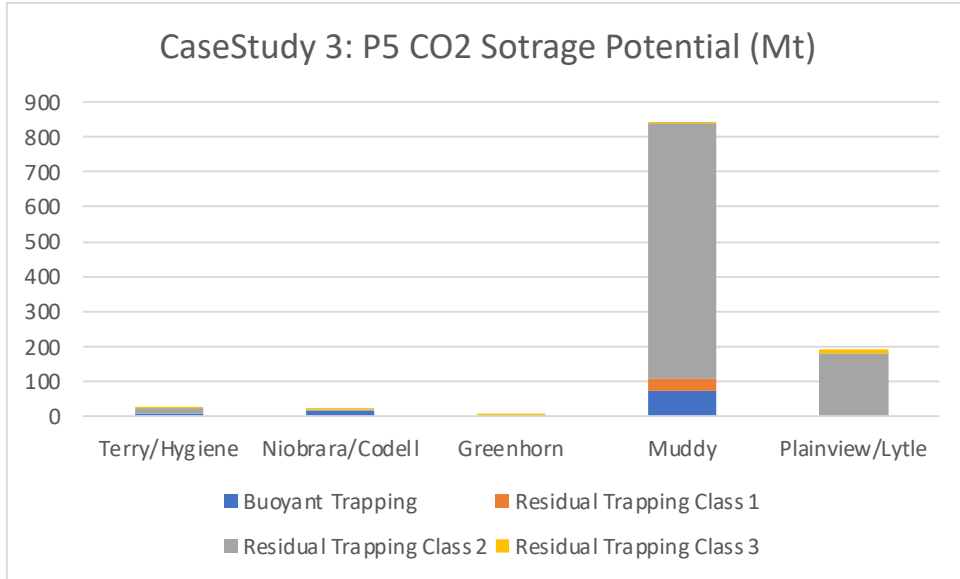


Figure 23: Case Study 3A: P5 CO2 Storage Potential

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a

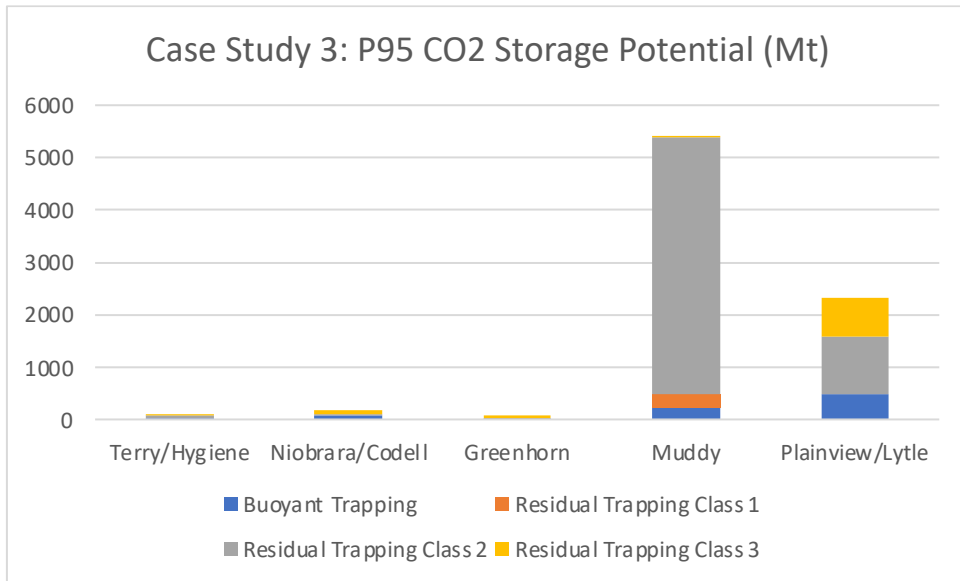


Figure 24: Case Study 3A: P95 CO2 Storage Potential

Source: US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a