# Transport Infrastructure for Carbon Capture and Storage

**WHITEPAPER ON REGIONAL INFRASTRUCTURE FOR MIDCENTURY DECARBONIZATION**


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GREAT PLAINS INSTITUTE

REGIONAL CARBON CAPTURE DEPLOYMENT INITIATIVE

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# Executive Summary

Analysis by the International Energy Agency (IEA) has determined that deployment of carbon capture technology is critical to achieve midcentury US and global carbon reduction goals and temperature targets.[1] Carbon capture enables power and industrial sectors to reduce or eliminate carbon emissions while protecting and creating high-wage employment. For key carbon-intensive industries such as steel and cement, significant $CO_2$ emissions result from the mechanical or chemical nature of the production process itself, regardless of the source of process energy. Industrial $CO_2$ emissions account for 33% of US stationary emissions.[3] Carbon capture is therefore an essential emissions reduction tool for industries that are otherwise difficult to decarbonize even after switching to low-carbon electricity. IEA modeling estimates that more than 28 billion tons of $CO_2$ must be captured globally from industrial processes by 2060 in order to meet international decarbonization goals and temperature targets.[2]

Infrastructure is needed on a significant scale to decarbonize the industrial and power sectors, even when accounting for aggressive low-carbon and renewable energy adoption. In addition to the economy-wide retrofit of carbon capture equipment at industrial and power facilities, regional scale transport infrastructure will be required to deliver captured $CO_2$ to sites of utilization and long-term storage. Previous work by the State Carbon Capture Work Group, an initiative facilitated by the Great Plains Institute, identified the limitations of building $CO_2$ transport infrastructure on a project-by-project basis and explored the long-term benefit of "super-sizing" $CO_2$ infrastructure to enable expanded capacity in the future.[4] Thus, this analysis sought to answer the question:

**What is the scale and design necessary for regional $CO_2$ transport infrastructure to meet US midcentury decarbonization goals in the industrial and power sectors?**

As seen in the maps included in this white paper, many of the industrial and power facilities in the United States are located in regions without significant deep saline or hydrocarbon geologic formations. Long distance transport infrastructure can unlock the economic potential for these facilities to sell captured $CO_2$ and earn tax credits for storage under Section 45Q. $CO_2$ transport infrastructure achieves beneficial economies of scale with higher volumes of $CO_2$ delivered. Large trunk lines designed to carry $CO_2$ from many facilities toward many storage sites can achieve a lower transport cost over long distances than lines with capacity designed for only one or a handful of capture projects. Long-term, coordinated planning on regional $CO_2$ transport corridors will result in optimized, regional scale infrastructure that minimizes costs, land use, and construction requirements while maximizing decarbonization across industrial and power sectors throughout the United States. This whitepaper presents the results of a two-year modeling effort to identify such regional scale $CO_2$ transport infrastructure that would serve existing facilities and allow participation by new capture projects and facilities in the future.

This analysis identified the most feasible near- and medium-term opportunities for deployment of carbon capture equipment at individual emitting facilities and focused on the Western, Midwestern, Plains, and Gulf regions of the US. The technological and economic limitations of deploying carbon capture at each emitting facility were considered. Los Alamos National Laboratory's SimCCS model was deployed to create theoretical $CO_2$ transport networks that minimized costs and maximized storage while protecting natural resources, public lands, population centers, indigenous or tribal lands, and a variety of other geographic factors. The scenarios presented here are only for theoretical consideration across broad geographic areas and are not meant to identify or proscribe the specific location of $CO_2$ transport infrastructure.

**This whitepaper presents the results of a two-year modeling effort to identify regional scale $CO_2$ transport infrastructure that would serve existing facilities and allow participation by new capture projects and facilities in the future.**

This process identified 1,517 45Q-eligible facilities across the United States that emit a total of 2,352 million metric tons of $CO_2$ annually. This accounts for 89% of total US stationary $CO_2$ emissions.[5] A facility-specific technical and financial screening then identified 418 facilities as near- and medium-term candidates for capture retrofit within the study region. More detail on this facility selection process is included in the methodological appendix. These near- and medium-term facilities emit 797 million metric tons of $CO_2$ per year, of which 358 million metric tons can be feasibly captured at relatively low cost under today's policy context and with conservative economic assumptions.

Using the SimCCS model, this analysis identified a regional network of $CO_2$ transport infrastructure that can achieve the capture, delivery, and storage of nearly 300 million tons of anthropogenic $CO_2$ based on near- and medium-term economics that include the Section 45Q tax credit. Cost estimates indicate that beneficial economies of scale are achieved via large shared trunk lines that reduce the per-ton cost of $CO_2$ transport. Analysis indicated that smaller pipelines built for single projects, or small feeder lines that connect individual facilities, result in relatively higher per-ton transport costs along those segments. These cost estimates were conducted using average rates of return for capital investments and show potential to enable capture at facilities that have moderate to relatively high capture cost through policies that provide low cost financing or other support.

Further sensitivity studies revealed two findings:

First, that near-term potential currently exists for industrial sectors with relatively low costs of capture (e.g. ethanol) to participate in a shared transport corridor to sites of storage in Kansas, Oklahoma, and Texas.

Second, that technical storage potential in deep saline formations nationwide offers a low-cost opportunity for local storage, pending site-specific geological characterization, that will allow full buildout to nearly any facility that qualifies for 45Q under currently defined minimum thresholds for $CO_2$ emissions.

## OPPORTUNITIES FOR CARBON CAPTURE, STORAGE, AND REGIONAL $CO_2$ TRANSPORT INFRASTRUCTURE

This analysis identified 1,517 industrial and power facilities throughout the United States where stationary $CO_2$ emissions are sufficient to meet minimum thresholds for the Section 45Q tax credit (100,000 metric tons per year and 500,000 metric tons per year for industrial and power facilities, respectively). These facilities emit an approximate total of 2.3 billion tons of $CO_2$ annually. Of those that would qualify for 45Q, 418 facilities met additional screening criteria to determine near- and medium-term potential for carbon capture retrofit under today's policy landscape and with conservative economic assumptions. The quantity of capturable $CO_2$ at optimized capture costs from these near- and medium-term facilities was estimated at approximately 358 million tons per year. The number of facilities, quantity of emissions, and estimated theoretical cost of capture for each industrial sector are listed in Table ii.

Figure i. Emitting facilities: 45Q Eligibility and near-term capture opportunities

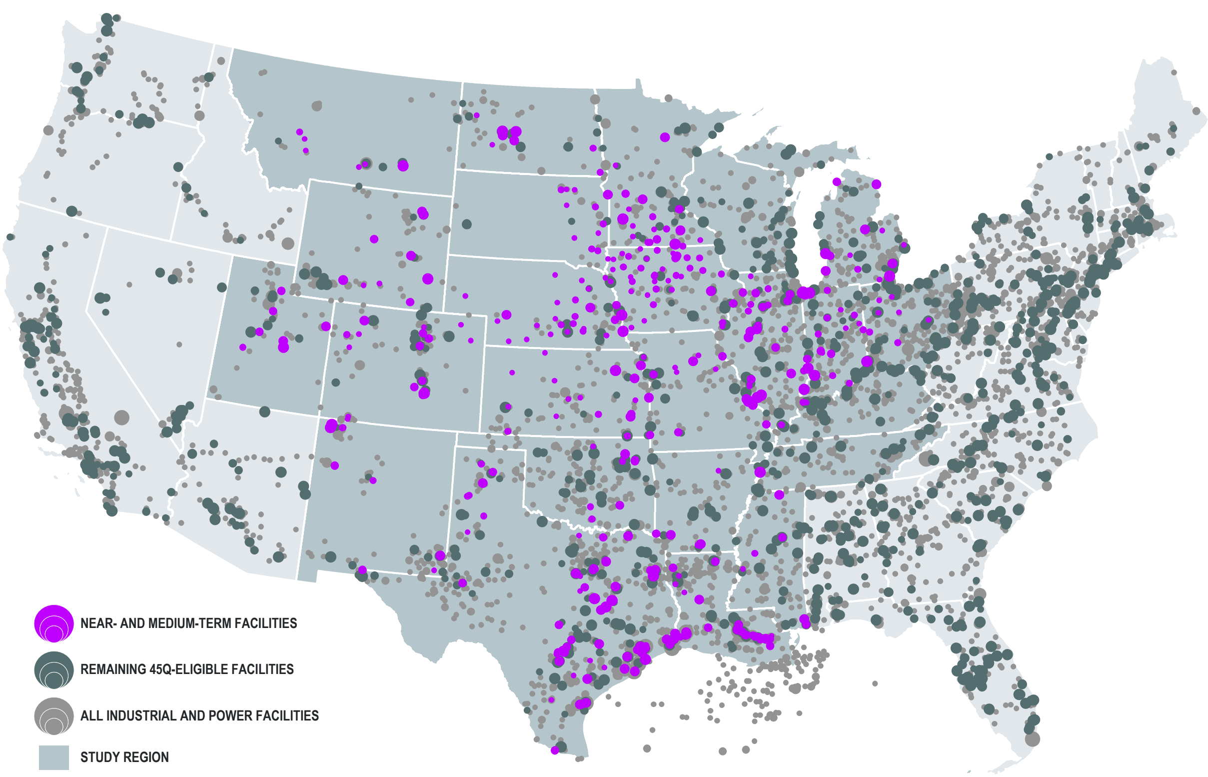


Figure authored by GPI based on data from EPA FLIGHT 2018.

## Table i. 45Q-Qualifying facilities and emissions by industry

| Industry | Number of Facilities | Share of 45Q-Eligible Facility Emissions | $CO_2$ | Biogenic $CO_2$ | Methane | Nitrous Oxide |
|---|---|---|---|---|---|---|
| Coal Power Plant | 308 | 53.8% | 1,269.6 | 0.3 | 3.0 | 6.2 |
| Gas Power Plant | 571 | 23.8% | 565.4 | 0.7 | 0.4 | 0.4 |
| Refineries | 78 | 6.9% | 163.3 | - | 0.6 | 0.4 |
| Cement | 135 | 3.7% | 88.8 | 0.9 | 0.1 | 0.2 |
| Hydrogen | 57 | 2.7% | 64.3 | - | 0.1 | 0.1 |
| Steel | 31 | 2.3% | 54.0 | - | 0.2 | - |
| Ethanol | 173 | 1.3% | 31.0 | 8.97 | 0.1 | 0.1 |
| Ammonia | 21 | 1.2% | 25.1 | 0.0 | 0.0 | 4.1 |
| Petrochemicals | 30 | 1.1% | 26.0 | 0.1 | 0.4 | 0.1 |
| Metals, Minerals & Other | 37 | 0.9% | 19.5 | - | 0.4 | - |
| Gas Processing | 40 | 0.9% | 19.9 | - | 0.7 | - |
| Chemicals | 16 | 0.8% | 8.7 | - | 0.0 | 10.4 |
| Pulp & Paper | 18 | 0.4% | 7.8 | 25.5 | 2.4 | 0.1 |
| Waste | 2 | 0.1% | 0.8 | 1.2 | 0.6 | - |
| **Grand Total** | **1,517** | **100%** | **2,344.2** | **29.3** | **9.1** | **22.1** |

All emissions are in million metric tons.

## Table ii. Near- and medium-term facilities, capture targets, and cost estimates

| Industry | Number of Facilities | Estimated Capturable $CO_2$ mmt/year | Share of Total Capturable Estimate | Average Estimated Cost $/ton | Range of Cost Estimates $/ton |
|---|---|---|---|---|---|
| Coal Power Plant | 58 | 143.4 | 40.1% | $56 | $46 - $60 |
| Gas Power Plant | 60 | 67.9 | 19.0% | $57 | $53 - $63 |
| Ethanol | 150 | 50.6 | 14.1% | $17 | $12 - $30 |
| Cement | 45 | 32.7 | 9.1% | $56 | $40 - $75 |
| Refineries | 38 | 26.5 | 7.4% | $56 | $43 - $68 |
| Steel | 6 | 14.6 | 4.1% | $59 | $55 - $64 |
| Hydrogen | 34 | 14.4 | 4.0% | $44 | $36 - $57 |
| Gas Processing | 20 | 4.5 | 1.3% | $14 | $11 - $16 |
| Petrochemicals | 2 | 1.7 | 0.5% | $59 | $57 - $60 |
| Ammonia | 3 | 0.9 | 0.3% | $17 | $15 - $21 |
| Chemicals | 2 | 0.7 | 0.2% | $30 | $19 - $40 |
| **Grand Total** | **418** | **357.8** | **100.0%** | **$39** | **$11 - 75** |

All emissions are in million metric tons.

## Figure ii. Optimized transport network for economy-wide $CO_2$ capture and storage

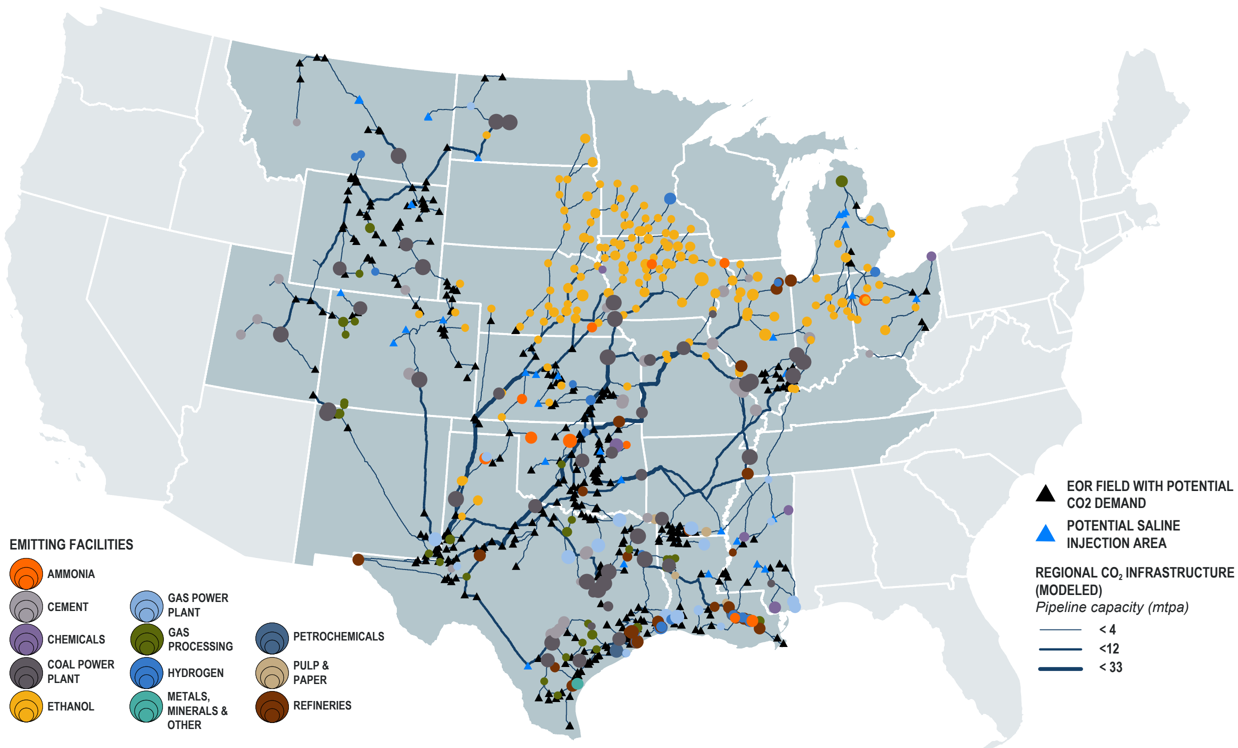


Figure authored by GPI based on results from the SimCCS model.

This analysis identified near- and medium-term opportunities for capture at industrial and power facilities along with likely geologic storage opportunities in deep saline formations and existing Enhanced Oil Recovery (EOR) operations. Shared regional $CO_2$ transport infrastructure will maximize $CO_2$ capture and storage and achieve the scale needed for US and international decarbonization targets, while minimizing investment requirements, transport costs, and land use. Los Alamos National Laboratory's SimCCS model was used to identify optimal regional scale transport networks that deliver $CO_2$ from capture facilities to storage locations identified by this analysis, resulting in Figure ii.

There are currently about 5,000 miles of $CO_2$ transport pipelines in the United States.[6] Economy-wide deployment of regional $CO_2$ transport infrastructure will require significant buildout. The scenario modeled here involves over 29,000 miles of $CO_2$ transport routes to deliver around 300 million tons of $CO_2$ in the near- and medium-term.

A full description of study approach, modeling methodology, and results can be found in the following sections of this report.

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## ABOUT THE REGIONAL CARBON CAPTURE DEPLOYMENT INITIATIVE

The Regional Carbon Capture Deployment Initiative is a network of 25 states, and growing, that work together to help ensure near-term deployment of carbon capture projects that will reduce carbon emissions, benefit domestic energy and industrial production, and protect and create high-wage jobs. The Initiative provides unique and valuable opportunities for governors, state officials, legislators, and other stakeholders to engage at the state, regional, and national levels.

The Regional Carbon Capture Deployment Initiative is staffed by the Great Plains Institute (GPI) at the invitation and direction of the State Carbon Capture Work Group.

## CONTRIBUTORS


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| | |
|---|---|
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## ACRONYM GUIDE

| | | |
|---|---|---|
| **ARI** | – | Advanced Resources International |
| **45Q** | – | Section 45Q Tax Credit for Carbon Oxide Sequestration |
| **CCS** | – | Carbon capture & storage |
| **$CO_2$** | – | Carbon dioxide |
| **CRF** | – | Capital recovery factor |
| **DOE** | – | US Department of Energy |
| **eGRID** | – | EPA's Emissions & Generation Resource Integrated Database |
| **EIA** | – | US Energy Information Administration |
| **EOR** | – | Enhanced oil recovery |
| **EPA** | – | US Environmental Protection Agency |
| **FLIGHT** | – | EPA's Facility Level Information on GreenHouse gases Tool |
| **GHG** | – | Greenhouse gas |
| **IEA** | – | International Energy Agency |
| **IPCC** | – | Intergovernmental Panel on Climate Change |
| **kW** | – | Kilowatt |
| **MT** | – | Metric ton |
| **MMT** | – | Million metric tons (also as mmt) |
| **MTPA** | – | Metric tons per annum |
| **MW** | – | Megawatt |
| **NATCARB** | – | National Carbon Sequestration Database and Geographic Information System |
| **NETL** | – | National Energy Technology Laboratory |
| **O & M** | – | Operations & maintenance |
| **$SCO_2T$** | – | Sequestration of $CO_2$ Tool |
| **SMR** | – | Steam Methane Reformer |
| **Ton** | – | All instances of "ton" in this paper are considered metric ton |
| **USGS** | – | United States Geological Survey |

## EXECUTIVE SUMMARY REFERENCES


1 International Energy Agency, 20 Years of Carbon Capture and Storage: Accelerating Future Deployment (2016).

2 International Energy Agency, Transforming Industry through CCUS. May 2019. https://www.iea.org/reports/transforming-industry-through-ccus

3 United States Environmental Protection Agency, Summary GHG Data 2016 (as of August 19, 2018), August 19, 2018, https://www.epa.gov/sites/production/files/2018-10/ghgp_data_2016_8_19_2018.xlsx.

4 State $CO_2$-EOR Deployment Work Group, 21st Century Infrastructure. February 2017. https://www.betterenergy.org/wp-content/uploads/2018/01/White_Paper_21st_Century_Infrastructure_$CO_2$_Pipelines_0.pdf

5 United States Environmental Protection Agency, Summary GHG Data 2016 (as of August 19, 2018), 2018.

6 National Energy Technology Laboratory. A Review of the $CO_2$ Pipeline Infrastructure in the U.S. April 21, 2015. https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

# Analytical Overview

## GOALS AND RATIONALE

Meeting decarbonization goals in the United States will require significant investment and effort to retrofit carbon capture equipment on industrial and power operations where simply switching to low-carbon energy sources will not address emissions from the chemical and mechanical aspects of industrial production processes.

The United States has a vast abundance of $CO_2$ storage potential in geologic formations in many areas throughout the country, including in deep saline and petroleum basins. In many cases, it makes economic sense to store captured $CO_2$ in deep saline formations within the vicinity of capture facilities. Where emissions occur in regions without significant geologic opportunity, however, $CO_2$ transport infrastructure is required to deliver captured $CO_2$ to markets for utilization and storage.

Under today's policy context, which includes the Section 45Q tax credit, it is already a positive economic proposition in some areas and industry sectors to finance regional $CO_2$ transport infrastructure that will essentially be paid for through sales revenue and tax credits. As nationwide efforts and investment in decarbonization continue toward midcentury, additional capture facilities will benefit from regional transport infrastructure and storage locations for captured $CO_2$. Regional transport infrastructure that is planned and built to allow for additional future capacity will contribute to maximizing $CO_2$ storage and minimizing transport costs, capital investment requirements, and land use impact.

Through the identification and assessment of existing $CO_2$ capture opportunities and storage potential and location, as well as the modeling of regional transport infrastructure, **this analysis aimed to study the following research questions:**

1. What is the total potential for $CO_2$ capture at industrial and power facilities where capture retrofit is technically and economically feasible?

2. Where are the existing opportunities for safe, secure, and long-term geologic $CO_2$ storage in deep saline formations and petroleum basins? Where are these areas in relation to capture opportunities?

3. What is the scale and design required for regional $CO_2$ transport infrastructure to deliver $CO_2$ from sources identified in Question 1 to the markets and storage locations identified in Question 2? Furthermore, what investment, scale, and planning are required to build regional $CO_2$ transport infrastructure that enables the economy-wide capture of $CO_2$ required by US midcentury decarbonization goals and global temperature targets?

## STUDY APPROACH

This analysis was conducted on the behalf of the Regional Carbon Capture Deployment Initiative through a collaboration of the Great Plains Institute, Los Alamos National Laboratory, Montana State University, Stanford University, Indiana University, the University of Wyoming Enhanced Oil Recovery Institute, and numerous others. Data, technical support, and consultation were provided by Advanced Resourced International, Inc., the National Energy Technology Laboratory, and participants from a broad variety of industry and nongovernmental organizations through the Regional Carbon Capture Deployment Initiative.

Nationwide **storage potential in deep saline geologic formations** was determined using the Sequestration of $CO_2$ Tool ($SCO_2T$), a reduced order model created by Los Alamos National Laboratory and Indiana University that integrates data from the US Department of Energy's National Carbon Sequestration Database and Geographic Information System (NATCARB) Carbon Storage Atlas and United States Geological Survey (USGS).[1] $SCO_2T$ provides estimates for technical storage potential, porosity, thickness, and theoretical storage costs for each significant saline formation across the US on a geographic grid of 10 $km^2$ cells.

Potential **demand for anthropogenic $CO_2$ from existing enhanced oil recovery (EOR) operations** was calculated by Advanced Resources International, Inc. (ARI), according to a proprietary model based on petroleum basin geology and historic operations.[2] For this analysis, average annual rates of purchase for $CO_2$ at $20 per ton were estimated by ARI for existing operations under two oil price scenarios, at $40 per barrel and $60 per barrel. For near- and medium-term scenarios, this study relied on estimates based on the more conservative $40 per barrel oil price scenario.

**Stationary emissions from industrial and power facilities** published by the US Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program were collected using the Facility Level Information on GreenHouse Gases Tool (FLIGHT). FLIGHT publishes emission levels for criteria pollutants specific to each applicable GHG Reporting Subpart activity, such as electricity generation, ammonia manufacturing, cement production, and iron and steel production, among others.[3] Direct $CO_2$ emission levels were used to determine facility eligibility for Section 45Q tax credits for $CO_2$ capture at minimum thresholds of 100,000 tons and 500,000 tons per year for industrial and power facilities, respectively.[4]

These **45Q-eligible facilities** and their process-specific emissions were compiled into a database, against which a screening process was applied based on facility operation, production, energy use, heat rate, and other factors. This screening process was intended to identify **potential near- and medium-term facilities** that could participate in regional $CO_2$ transport infrastructure networks for capture and delivery of $CO_2$ under today's market and policy context. EPA's Emissions & Generation Resource Integrated Database (eGRID)[5] provided unit- and generator-specific operational data and was supplemented by power plant information from the proprietary ABB Ability Velocity Suite.[6]

A meta-study and literature review of published capture costs, as well as capital, financing, and operation and maintenance costs for capture equipment such as amine solvent units and compressor systems, was conducted to calculate **theoretical capture costs** based on the emission quantity, operational patterns, and energy costs of each facility. A detailed description of screening process criteria and capture cost estimation can be found in the methodological appendix of this report.

Average estimated capture costs for each industrial sector considered by this study are published in the Summary of Findings section on the following pages of this report.

Los Alamos National Laboratory's SimCCS model [7] was used to simulate **optimized $CO_2$ transport infrastructure** to link cost effective sources of $CO_2$ to locations of potential economic demand for utilization and storage. SimCCS minimizes the cost of $CO_2$ transport routes over a cost surface based on numerous layers of geographic information and right-of-way concerns such as urban areas, bodies of water, publicly-owned lands and natural resources, indigenous or tribal lands, and existing infrastructure. The physical and financial requirements of transport infrastructure were calculated and analyzed using the National Energy Technology Laboratory (NETL) $CO_2$ Transport Cost Model, which were also integrated into the cost calculations of SimCCS.[8]

Through an iterative process, a series of scenarios were constructed to explore the research questions outlined in the previous section of this report. These research questions focus on identifying broad geographic corridors for regional $CO_2$ transport; modeling which facilities and segments of pipeline might break even or produce revenue within the existing and near-term economic context; determining how potential economic demand for $CO_2$ at existing EOR operations and technical storage potential in nearby deep saline formations can provide opportunities for $CO_2$ capture retrofit; assessing the overall opportunity for carbon capture and storage under the Section 45Q tax credit; and finally, identifying the remaining barriers and areas in need of support to fully realize the potential for economy-wide capture and storage of $CO_2$ to meet midcentury decarbonization goals.

## SUMMARY OF FINDINGS

### Capture Feasibility: Potential Sources of $CO_2$

Each year, stationary power sources in the US emit nearly 2 billion metric tons of GHG emissions, while US industrial facilities emit nearly 1 billion metric tons of GHG emissions. Combined emissions from these power and industrial facilities comprise roughly half of all US GHG emissions.[9]

Of the 6,586 power and industrial facilities reported by the US EPA, 1,517 are likely eligible for the 45Q tax credit. These 45Q-eligible facilities make up 89% of all $CO_2$ emissions from US power and industrial facilities. This analysis identified 418 facilities as candidates for near- and medium-term deployment, with the combined potential to capture 358 million metric tons of $CO_2$ emissions annually.

Table 3. Stationary emissions from US industrial and power facilities

| Industry | Number of Facilities | Share of US Stationary $CO_2$ Emissions | $CO_2$ | Biogenic $CO_2$ | Methane | Nitrous Oxide |
|---|---|---|---|---|---|---|
| Coal Power Plant | 336 | 45% | 1,270.6 | 0.4 | 3.0 | 6.2 |
| Gas Power Plant | 963 | 21% | 581.3 | 0.9 | 0.5 | 0.4 |
| Refineries | 121 | 6% | 171.3 | 0.0 | 0.7 | 0.4 |
| Metals, Minerals & Other | 1,511 | 5% | 101.1 | 5.3 | 42.3 | 0.4 |
| Gas Processing | 1,246 | 4% | 88.9 | 0.2 | 9.9 | 0.1 |
| Waste | 1,225 | 4% | 11.1 | 17.5 | 86.7 | 0.4 |
| Cement | 149 | 3% | 90.4 | 0.9 | 0.1 | 0.2 |
| Hydrogen | 79 | 2% | 66.2 | - | 0.1 | 0.1 |
| Steel | 82 | 2% | 58.5 | - | 0.3 | 0.0 |
| Chemicals | 266 | 2% | 30.4 | 0.7 | 0.1 | 13.1 |
| Petrochemicals | 61 | 2% | 46.1 | 0.1 | 0.5 | 0.1 |
| Pulp & Paper | 225 | 2% | 37.1 | 112.2 | 5.2 | 0.5 |
| Other Power Plant | 118 | 1% | 36.4 | 9.2 | 0.2 | 0.2 |
| Ethanol | 181 | 1% | 31.2 | 9.2 | 0.1 | 0.1 |
| Ammonia | 23 | 1% | 25.21 | - | - | 4.1 |
| **Grand Total** | **6,586** | **100%** | **2,645.8** | **147.9** | **149.5** | **26.2** |

All emissions are in million metric tons.

**45Q-eligible facilities make up 89% of all $CO_2$ emissions from US power and industrial facilities. This analysis identified 418 facilities as candidates for near- and medium-term deployment, with the combined potential to capture 358 million metric tons of $CO_2$ emissions annually.**

## Summary of Findings: 45Q Eligibility

Figure 3. 45Q-eligible facilities by industry and emissions

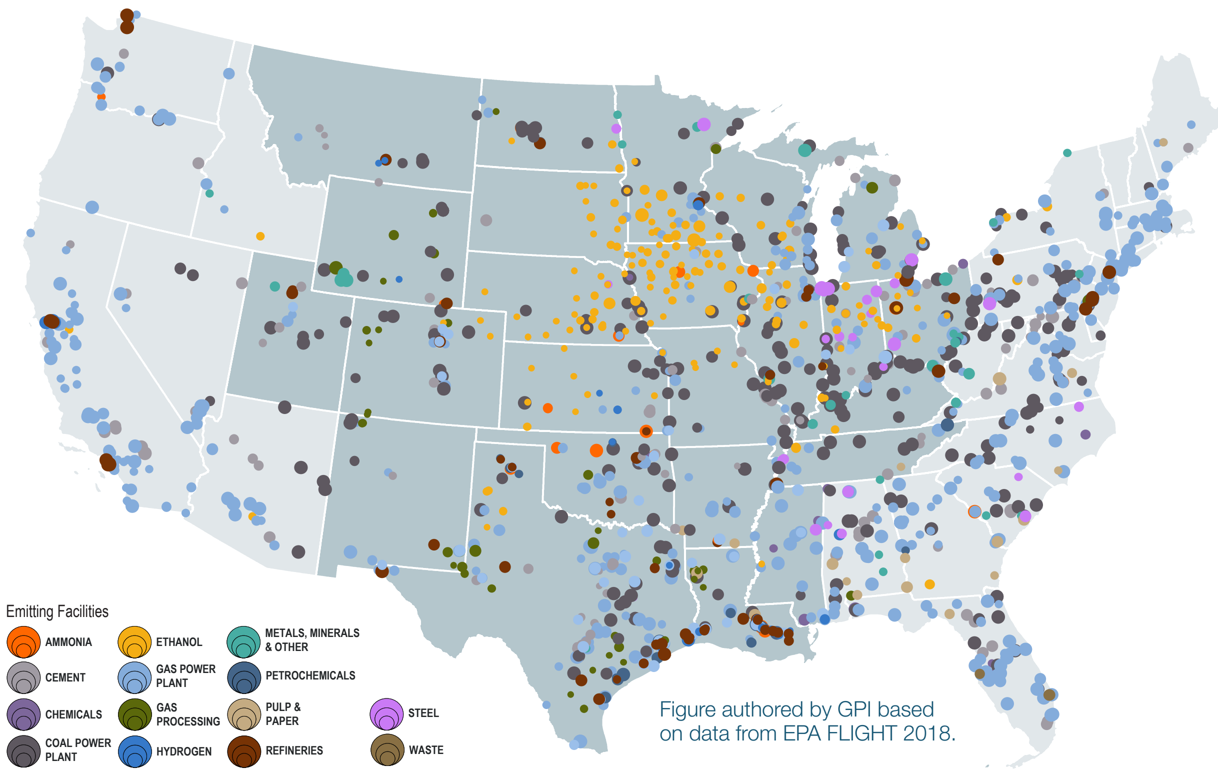



Table 4. 45Q-eligible facilities by industry and emissions

| Industry | Number of Facilities | Share of 45Q-Eligible Emissions | $CO_2$ | Biogenic $CO_2$ | Methane | Nitrous Oxide |
|---|---|---|---|---|---|---|
| Coal Power Plant | 308 | 53.8% | 1,269.6 | 0.3 | 3.0 | 6.2 |
| Gas Power Plant | 571 | 23.8% | 565.4 | 0.7 | 0.4 | 0.4 |
| Refineries | 78 | 6.9% | 163.3 | - | 0.6 | 0.4 |
| Cement | 135 | 3.7% | 88.8 | 0.9 | 0.1 | 0.2 |
| Hydrogen | 57 | 2.7% | 64.3 | - | 0.1 | 0.1 |
| Steel | 31 | 2.3% | 54.0 | - | 0.2 | - |
| Ethanol | 173 | 1.3% | 31.0 | 8.97 | 0.1 | 0.1 |
| Ammonia | 21 | 1.2% | 25.1 | 0.0 | 0.0 | 4.1 |
| Petrochemicals | 30 | 1.1% | 26.0 | 0.1 | 0.4 | 0.1 |
| Metals, Minerals & Other | 37 | 0.9% | 19.5 | - | 0.4 | - |
| Gas Processing | 40 | 0.9% | 19.9 | - | 0.7 | - |
| Chemicals | 16 | 0.8% | 8.7 | - | 0.0 | 10.4 |
| Pulp & Paper | 18 | 0.4% | 7.8 | 25.5 | 2.4 | 0.1 |
| Waste | 2 | 0.1% | 0.8 | 1.2 | 0.6 | - |
| **Grand Total** | **1,517** | **100%** | **2,344.2** | **29.3** | **9.1** | **22.1** |

All emissions are in million metric tons.

## Summary of Findings: Near- and Medium-Term Potential Capture Retrofit

Figure 4. Identified near- and medium-term capture facilities within study region

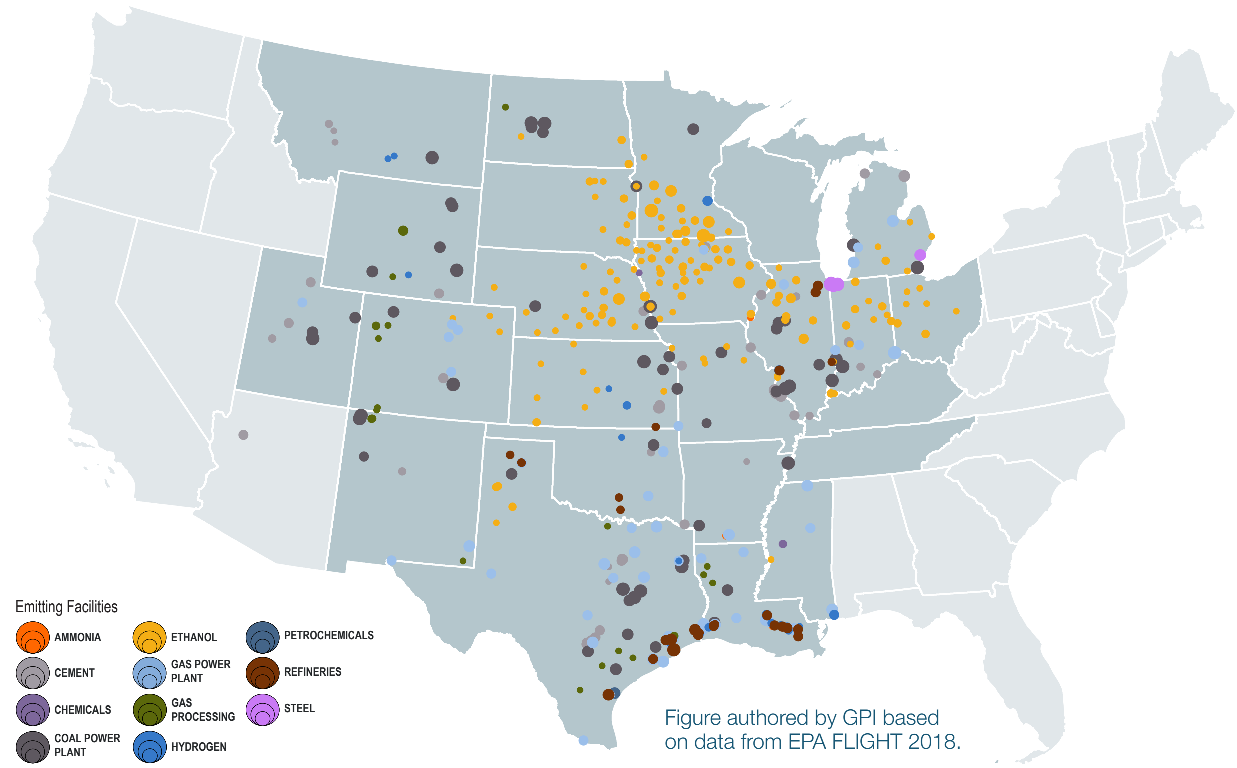


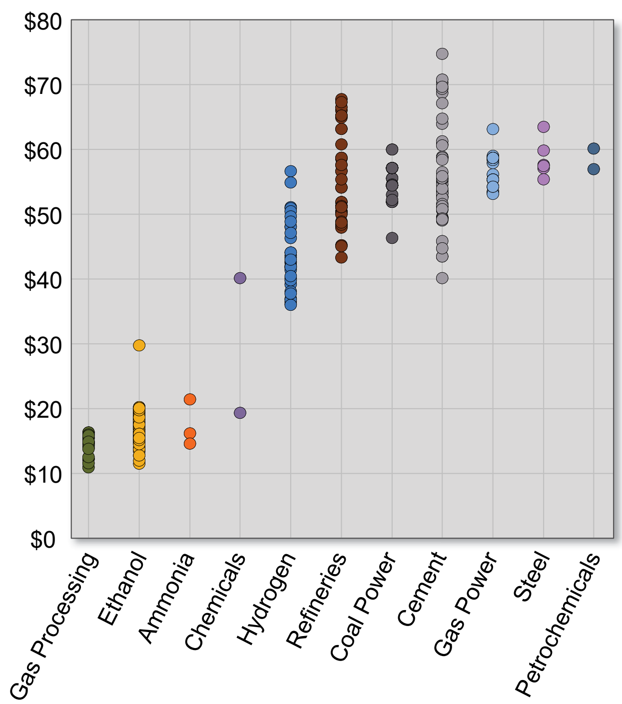

Table 5. Identified near- and medium-term capture facilities

| Industry | Number of Facilities | Average Estimated Cost $/ton | Estimated Capturable $CO_2$ | Share of Total Capturable Estimate |
|---|---|---|---|---|
| Coal Power Plant | 58 | $56 | 143.4 | 40.1% |
| Gas Power Plant | 60 | $57 | 67.9 | 19.0% |
| Ethanol | 150 | $17 | 50.6 | 14.1% |
| Cement | 45 | $56 | 32.7 | 9.1% |
| Refineries | 38 | $56 | 26.5 | 7.4% |
| Steel | 6 | $59 | 14.6 | 4.1% |
| Hydrogen | 34 | $44 | 14.4 | 4.0% |
| Gas Processing | 20 | $14 | 4.5 | 1.3% |
| Petrochemicals | 2 | $59 | 1.7 | 0.5% |
| Ammonia | 3 | $17 | 0.9 | 0.3% |
| Chemicals | 2 | $30 | 0.7 | 0.2% |
| **Grand Total** | **418** | **$39** | **357.8** | **100.0%** |

All emissions are in million metric tons.

This analysis included a literature review and meta-study of published costs of capture for a variety of industries and equipment configurations. Unit- and process-specific emissions were identified to determine optimal capture quantities while minimizing overall capital investment requirements, thereby optimizing cost of capture on a per ton basis. Table 6 reports the average and range of estimated capture costs calculated for this study. A full description of the sources, equipment, capital financing scenarios, and cost calculations can be found in the methodological appendix of this report.

## Figure 5 & Table 6. Estimated capture cost per industry for near-term facilities in study area

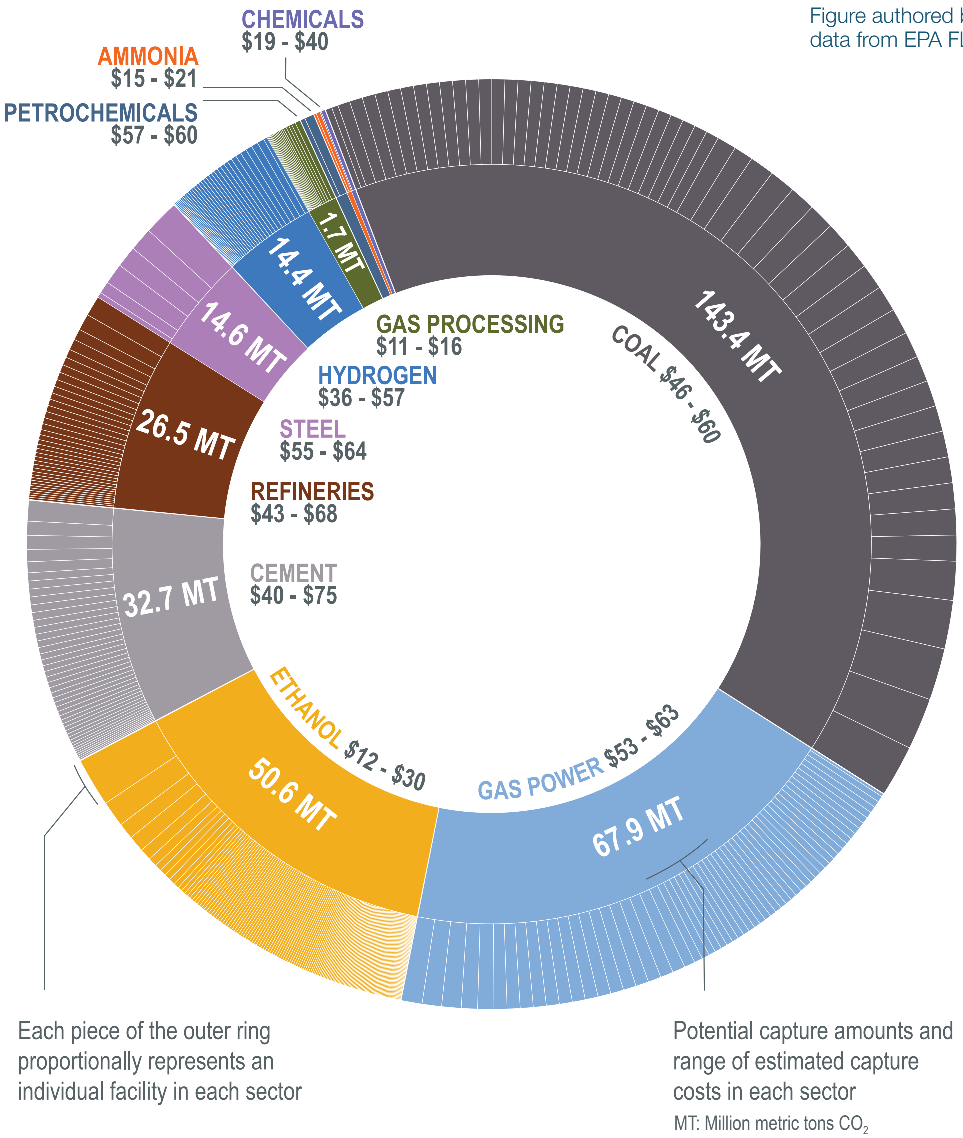



| Industry | Average Estimated Cost $/ton | Range of Cost Estimates $/ton |
|---|---|---|
| Gas Processing | $14 | $11 - $16 |
| Ethanol | $17 | $12 - $30 |
| Ammonia | $17 | $15 - $21 |
| Chemicals | $30 | $19 - $40 |
| Hydrogen | $44 | $36 - $57 |
| Refineries | $56 | $43 - $68 |
| Coal Power Plant | $56 | $46 - $60 |
| Cement | $56 | $40 - $75 |
| Gas Power Plant | $57 | $53 - $63 |
| Steel | $59 | $55 - $64 |
| Petrochemicals | $59 | $57 - $60 |

Figure authored by GPI based on data from EPA FLIGHT 2018.

Figure 6. Estimated capture target and cost of capture per industry for near- and medium-term capture opportunities in study area

Figure authored by GPI based on data from EPA FLIGHT 2018.



## Summary of Findings: $CO_2$ Storage Opportunities

Figure 7. Geologic deep saline formations and existing oil fields with $CO_2$ storage potential

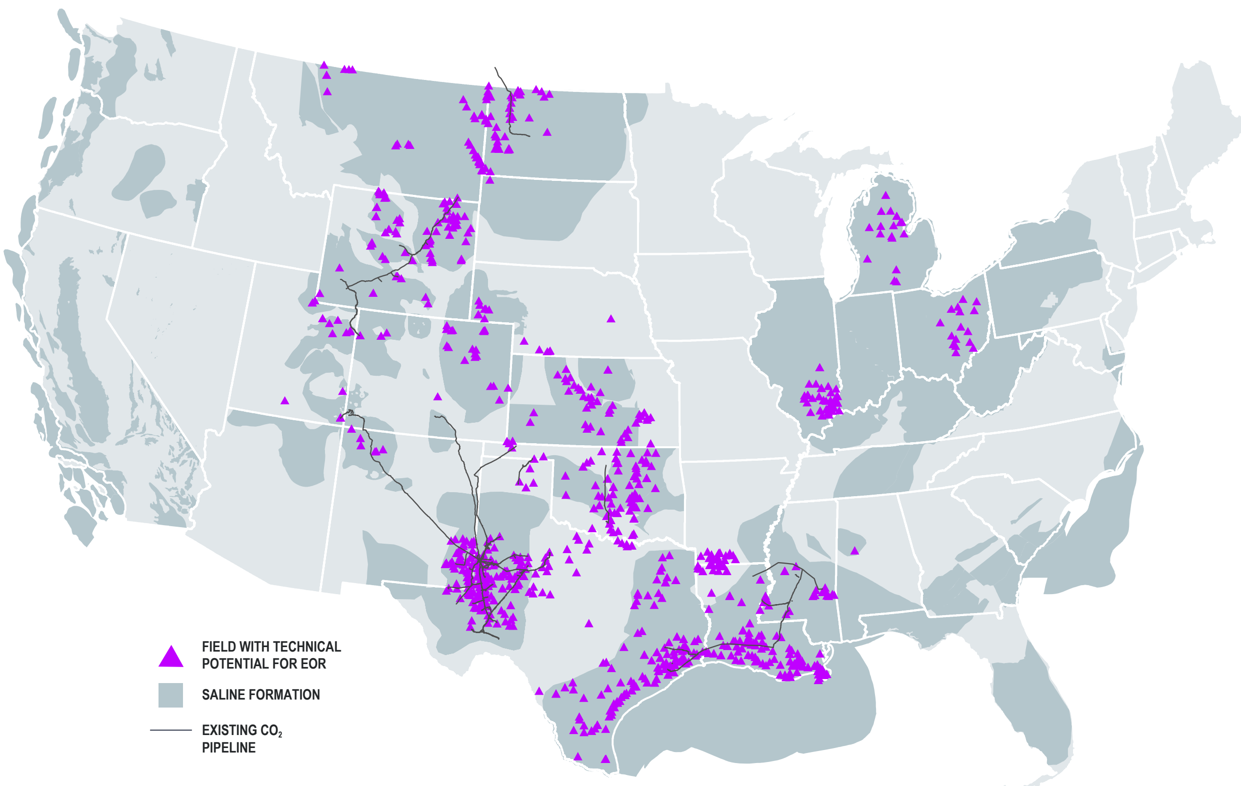



Figure authored by GPI based on data from ARI and NATCARB.

A total technical potential for storage in deep saline formations of over 4.5 trillion metric tons was identified within the study region. Meanwhile, existing EOR operations within this same region may have the potential to store over 500 million metric tons of $CO_2$ per year, or over 10 billion metric tons over 20 years. These estimates refer to technical potential without consideration of costs and economic feasibility. For modeling, this analysis did consider the likely market price of $CO_2$ for utilization and storage by EOR, as well as the estimated cost of injection, storage, and long-term monitoring in deep saline formations. The modeling scenarios presented in this report focus on EOR operations and locations within deep saline formations that present feasible economics under today's policy and market context, accounting for estimated costs of capture, the Section 45Q tax credit, transportation costs, injection and storage costs, the delivered price of $CO_2$, and potential oil revenue. This study was not intended to perform further geologic characterization of deep saline formations to identify specific injection sites. Local planning and geologic characterization must be performed to identify feasible injection sites within broader geologic formations.

## Summary of Findings: $CO_2$ Transport Infrastructure for Economy-Wide Deployment

As outlined in the sections above, and detailed in the methodological appendix of this paper, this analysis identified near- and medium-term opportunities for capture at industrial and power facilities along with likely geologic storage opportunities in deep saline formations and existing EOR operations. To maximize $CO_2$ capture and storage and approach the scale needed for US decarbonization targets and international temperature targets, shared regional $CO_2$ transport infrastructure will minimize investment requirements, transport costs, and land use. Los Alamos National Laboratory's SimCCS model was used to identify optimal regional scale transport networks that deliver $CO_2$ from capture facilities to storage locations identified by this analysis, resulting in Figure 8.

Figure 8. Optimized transport network for economy-wide $CO_2$ capture and storage

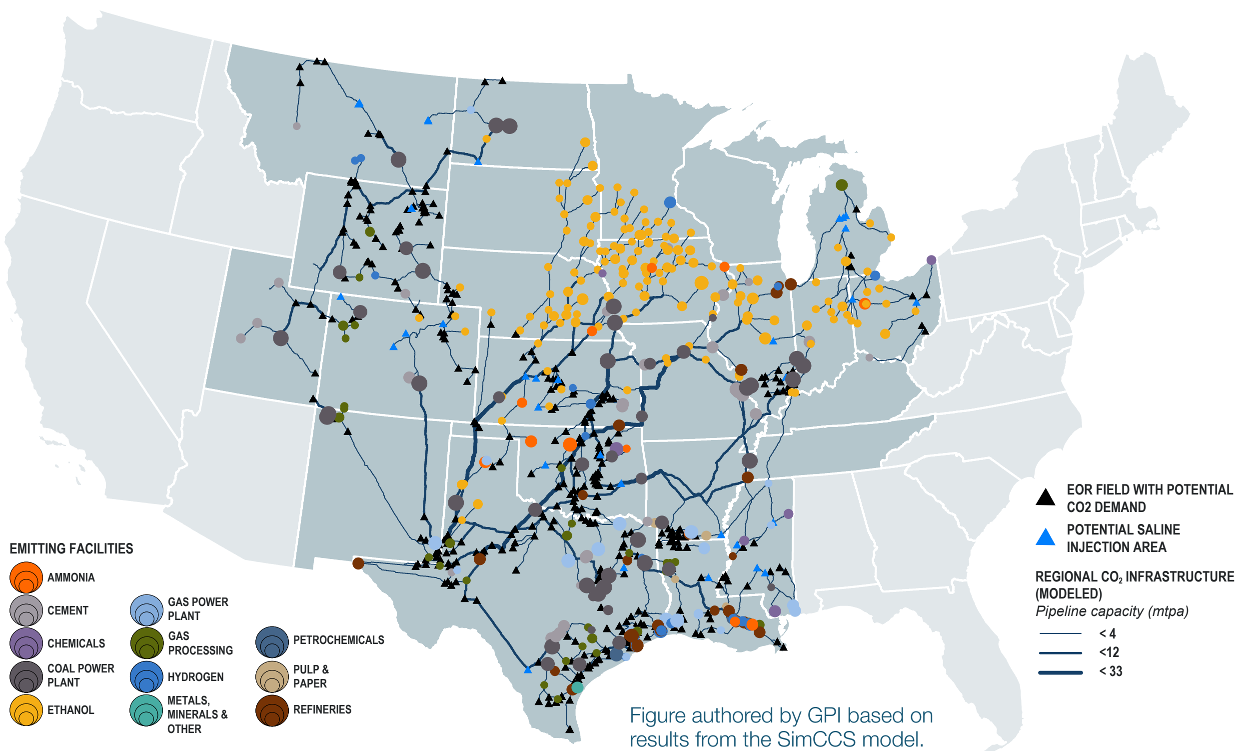



Figure authored by GPI based on results from the SimCCS model.

Table 7. Miles of $CO_2$ pipeline modeled, by diameter

| **Diameter** | 4" | 6" | 8" | 12" | 16" | 20" | 24" | 30" |
|---|---|---|---|---|---|---|---|---|
| **Length** miles | 4,712 | 6,063 | 8,560 | 5,834 | 2,675 | 1,790 | 59 | 16 |

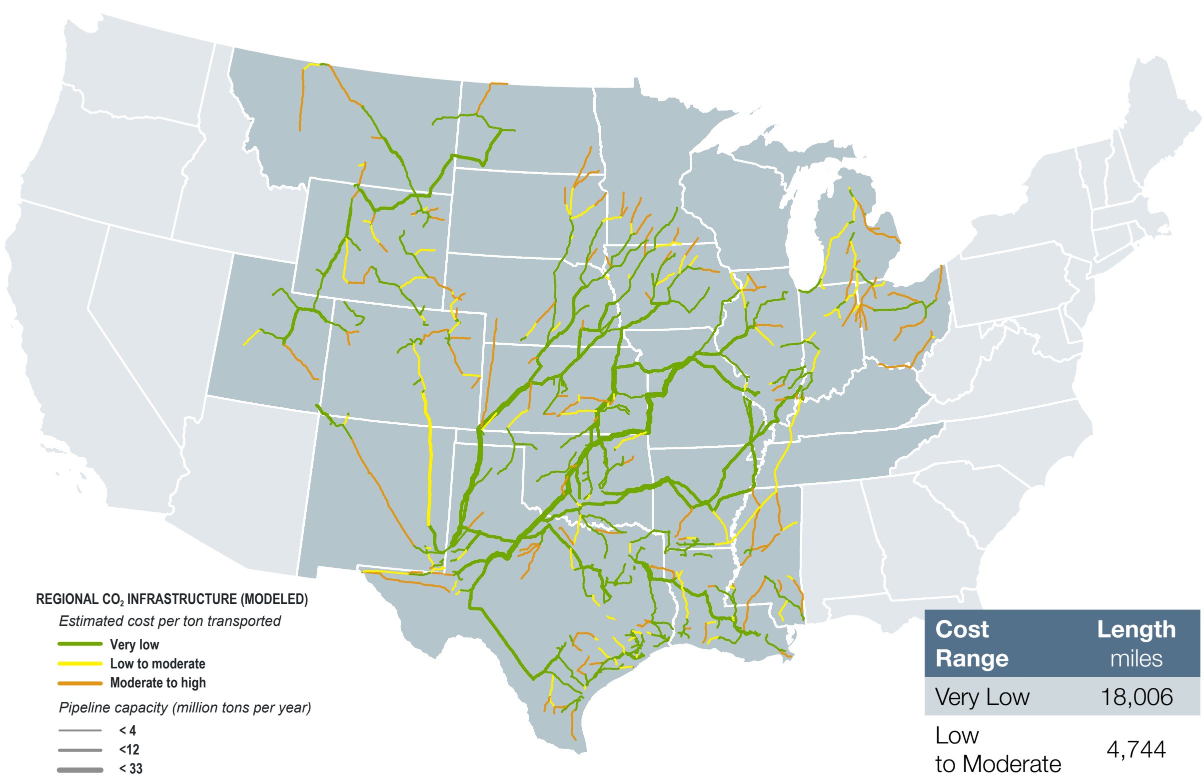
## Summary of Findings: Transport Costs

The NETL $CO_2$ Transport Cost Model was used to estimate capital investment, operational, and maintenance costs of each segment of the transport network according to its capacity and length. Costs were calculated at expected private sector rates of return on capital investment without additional support or low-cost financing.

As expected, costs on a per-ton basis are much lower for large shared trunk lines that transport huge volumes of $CO_2$ (more than 12 million metric tons per year), commonly achieving transport costs well below $10 per ton. Segments that transport between 4 and 12 million tons per year had estimated costs generally between $10 and $20 per ton. Small feeder lines that connect to individual capture facilities had moderately high per-ton transport costs due to relatively lower volume (100,000 to 4 million metric tons per year).

Under current economic conditions, transport costs would ideally fall between $10 and $20 per ton in order for capture and storage to economically break-even under Section 45Q. The higher per-ton delivered cost of individual facility feeder lines indicates that shared or coordinated investment of $CO_2$ transport infrastructure, and/or supportive policies such as low-cost financing, may be needed to achieve optimal regional scale transport infrastructure that minimizes total system cost while maximizing economy-wide $CO_2$ capture and storage.

Figure 9. Relative transport cost of network segments




| Cost Range | Length miles |
|---|---|
| Very Low | 18,006 |
| Low to Moderate | 4,744 |
| Moderate to High | 6,960 |

Figure authored by GPI based on results from the SimCCS model.

## Summary of Findings: High-Cost Sensitivity Scenario

Achieving US economy-wide decarbonization goals will likely require capital investment across numerous sectors and industries. Analysis from the IPCC found that carbon mitigation under the 2 degree C scenario would cost 138% more if carbon capture were not included as an emissions reduction strategy.[10] As shown above, while $CO_2$ transport infrastructure does represent a significant cost, the buildout of a shared regional-scale transport network will minimize the overall capital investment required.

To identify near-term opportunities for early stage buildout of this regional network, this study ran SimCCS in a strict economic pricing mode in which all infrastructure investment must be paid for by the sale of $CO_2$. Near-term candidates for capture retrofit were provided the option to invest in transport infrastructure to reach distant EOR operations with economic demand for $CO_2$, or to store in nearby saline formations at a cost (for injection, storage, and monitoring).

The results of this high-cost sensitivity show two things: First, that **there is immediate economic potential for geographically concentrated, low-cost industrial sources in the Midwest (e.g., ethanol facilities) to aggregate their $CO_2$ supply and deliver to storage locations at petroleum basins in Kansas, Oklahoma, and Texas.** Second, in areas with sufficient storage potential in deep saline formations, a variety of industries with low and moderate capture costs have economic potential to claim Section 45Q tax credits for local storage in nearby deep saline formations. This is also true for these same industries in areas with storage potential in petroleum basins, such as Louisiana, Oklahoma, Texas, and parts of the Rockies.

Figure 10. High-cost sensitivity with economic break-even

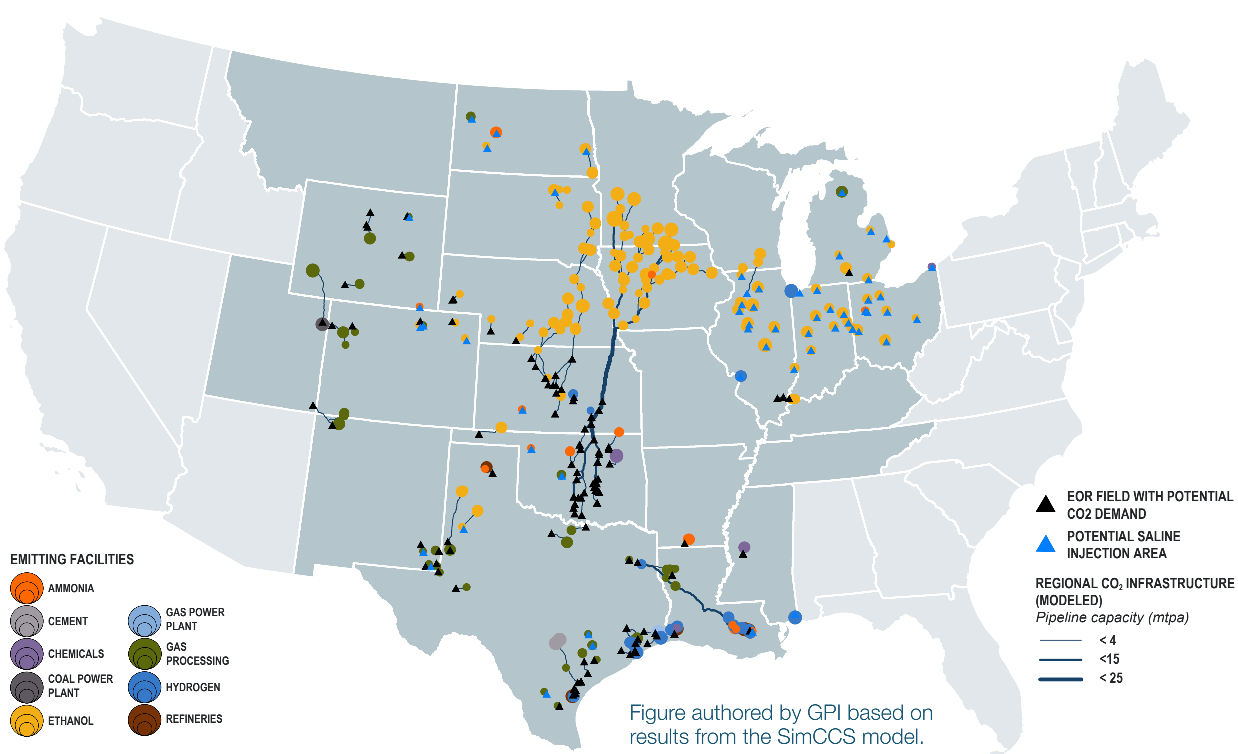



Figure authored by GPI based on results from the SimCCS model.

## Summary of Findings: Expansion of Storage in Deep Saline Formations

Based on the findings of the initial transport network optimization modeling and the following high-cost sensitivity model run, which identified additional economic potential for $CO_2$ storage in deep saline formations nearby capture facilities, a final regional-scale network scenario was modeled to optimize capture and transport infrastructure for storage at previously identified EOR operations and additional deep saline formations.

This aggressive saline scenario, illustrated in Figure 11, resulted in a regional $CO_2$ transport network similar to the initial scenario but with expanded storage in saline formations in the eastern parts of the Midwest, Gulf Coast states, and various locations throughout the Rockies. **This scenario achieved 669 million metric tons of $CO_2$ capture and storage, enabled by saline storage for an expanded set of 45Q-eligible facilities in addition to the near- and medium-term facilities.**

This study used geologic data for deep saline formations from NATCARB and the $SCO_2T$ saline storage database, as detailed in this paper's Study Approach section and the Methodological Appendix. Further geologic characterization of deep saline formations must be performed in order to identify actual injection and storage sites within local areas.

Figure 11. Expanded storage in deep saline formations and petroleum basins

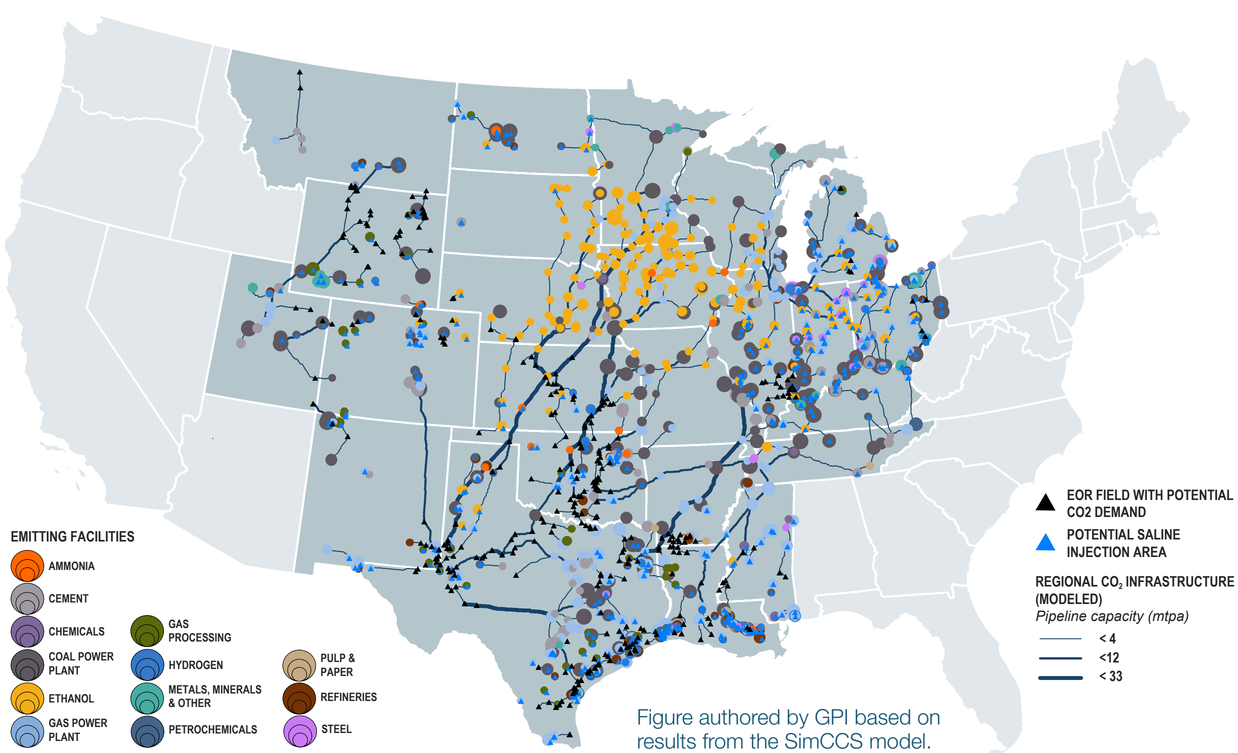



Figure authored by GPI based on results from the SimCCS model.

# Full Discussion of Findings and Results

## US DECARBONIZATION GOALS AND POLICY CONTEXT

Analysis by the International Energy Agency (IEA) has determined that deployment of carbon capture technology is critical to achieve midcentury US and global carbon reduction and temperature targets.[11] **IEA's modeling estimates that more than 28 billion tons of $CO_2$ must be captured globally from industrial processes by 2060.**[12] Decarbonizing the US and global economy will require significant capital investment. However, IPCC modeling suggests that pursuing decarbonization would cost 138% more without the use of carbon capture.[13] For key carbon-intensive industries such as steel and cement, significant $CO_2$ emissions result from the mechanical or chemical nature of the production process itself, regardless of the source of process energy. Carbon capture enables industrial sectors, which account for 33% of US stationary emissions, to reduce or eliminate carbon emissions while protecting and creating high-wage employment.[14] Carbon capture is therefore an essential emissions reduction tool for industries that are otherwise difficult to decarbonize even after switching to low-carbon electricity.

Figure 12. All major emitter facilities by industry and emissions

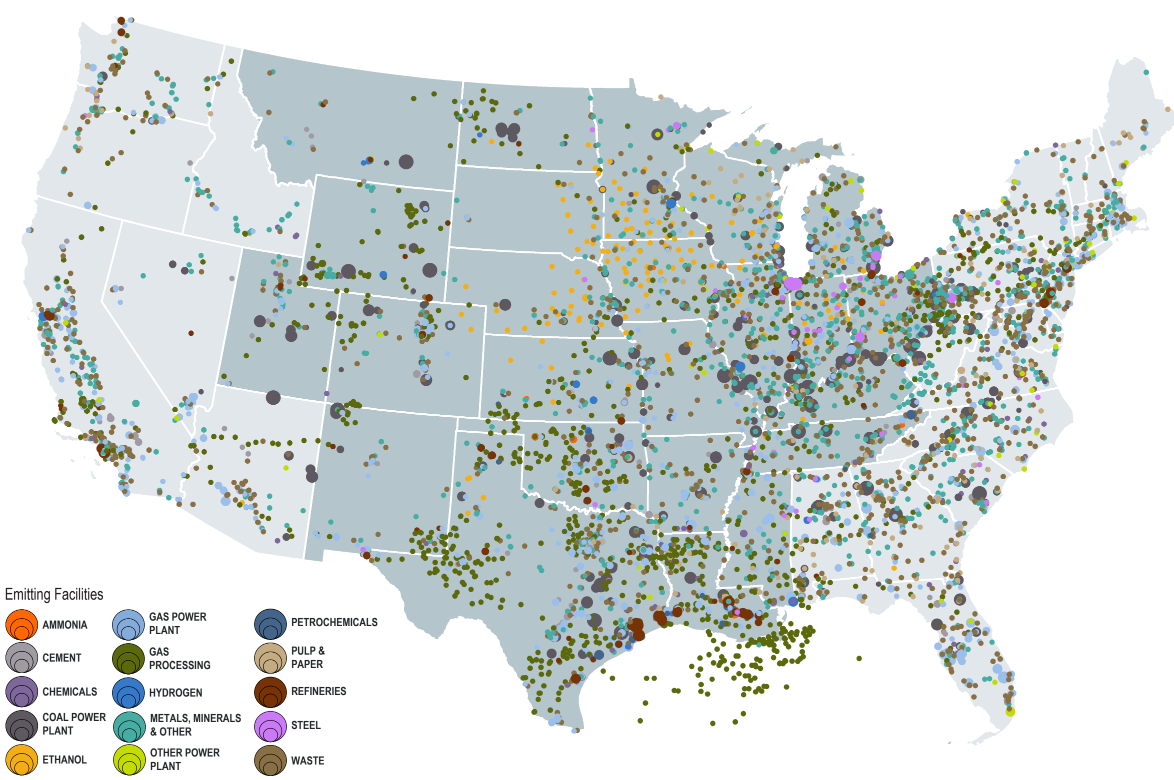



Figure authored by GPI based on data from EPA FLIGHT 2018.

### Section 45Q Tax Credit

Section 45Q of the US tax code provides a performance-based tax credit for carbon capture projects that can be claimed when an eligible project has securely stored the captured carbon dioxide ($CO_2$) in geologic formations, such as deep saline formations and petroleum basins, or beneficially used captured $CO_2$ or its precursor carbon monoxide (CO) as a feedstock to produce fuels, chemicals, and products such as concrete in a way that results in emissions reductions as defined by federal requirements.

**IEA's modeling estimates that more than 28 billion tons of $CO_2$ must be captured globally from industrial processes by 2060.**

The availability of the newly expanded and reformed 45Q tax credit reduces the cost and risk to private capital of investing in the deployment of carbon capture technology across a range of industries, including electric power generation, ethanol and fertilizer production, natural gas processing, refining, chemicals production, and the manufacture of steel and cement.

Eligibility is extended to three categories of carbon capture project, each with their own threshold for eligibility: Projects capturing carbon for a beneficial use other than EOR are eligible if they capture between 25,000 500,000 metric tons of $CO_2$/CO per year. All other industrial facilities (other than electric generating units), including direct air capture are eligible if they capture at least 100,000 metric tons of $CO_2$/CO per year. Electric generating units are eligible if they capture at least 500,000 metric tons of $CO_2$/CO per year. Meanwhile, the amount of credit generated is determined by how the $CO_2$ captured from an eligible project is ultimately used. Projects storing $CO_2$ geologically through EOR, and projects using $CO_2$ or CO for other beneficial uses, such as converting carbon emissions into fuels, chemicals, or useful products like concrete, generate \$35 per ton of $CO_2$ stored or utilized. Projects storing $CO_2$ in other geologic formations and not used in EOR generate \$50 per ton of $CO_2$ stored.

This analysis focused on industrial and power facilities that would meet the minimum capture thresholds for eligibility. It is important to note that eligible projects that begin construction within six years of the FUTURE Act's enactment (i.e., before January 1, 2024) can claim the credit for up to 12 years after being placed in service. This timeline underscores the urgency of this analysis, and of action on the part of commercial entities and other stakeholders.

## APPROACH, DATA, AND TOOLS

As summarized previously in this paper, this analysis relied on data and tools available from federal institutions and national laboratories to study power and industrial facility operations, geologic storage potential, and $CO_2$ transport routing and logistics.

### Power and Industrial Facilities: EPA FLIGHT and eGRID

Since 2010, the United States Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP) has collected and published greenhouse gas emissions data from large emitting facilities, suppliers of fossil fuels, and industrial gases that result in greenhouse gas (GHG) emissions when used, and facilities that inject carbon dioxide underground. Sources whose emissions are equal to or surpass 25,000 metric tons of $CO_2$ equivalent are required by law to submit emissions data to the GHGRP. In total, EPA's GHGRP gathers GHG data from over 8,000 facilities.[15] This data is published online as a resources called the EPA Facility Level Information on Greenhouse Gases Tool (FLIGHT).

This analysis utilized EPA FLIGHT data to provide detailed information about the emissions profile and other characteristics of emitter facilities in order to assess each emitter for potential carbon capture retrofit viability. This analysis did not consider smaller emitters that would not qualify for the 45Q tax credit, nor facilities that would suffer scale diseconomies if application of capture technology were to be retrofitted. Direct $CO_2$ emission levels were used to determine facility eligibility for Section 45Q tax credits for $CO_2$ capture at minimum thresholds of 100,000 tons and 500,000 tons per year for industrial and power facilities, respectively.[16]

These 45Q-eligible facilities and their process-specific emissions were compiled into a database, against which a screening process was applied based on facility operation, production, energy use, heat rate, and other factors. This screening process was intended to identify potential near- and medium-term facilities that might feasibly participate in regional $CO_2$ transport infrastructure networks for capture and delivery of $CO_2$ under today's market and policy context. The full screening methodology, criteria, and cost components are provided in the appendix of this document. EPA's Emissions & Generation Resource Integrated Database (eGRID)[17] provided unit- and generator-specific operational data and was supplemented by power plant information from the proprietary ABB Ability Velocity Suite.[18]

## Opportunities for Long-Term Storage of $CO_2$: $SCO_2T$ Saline Data

The Sequestration of $CO_2$ Tool ($SCO_2T$), created by Los Alamos National Laboratory and Indiana University, provided nation-wide assessment of geologic deep saline formations for $CO_2$ storage potential.[19] $SCO_2T$ compiles data from the USGS and the National Carbon Sequestration Database and Geographic Information System (NATCARB). NATCARB is administered by the US DOE's National Energy Technology Laboratory and contains data provided by several Regional Carbon Sequestration Partnerships (RCSP).

$SCO_2T$ employs reduced-order models to calculate physical characteristics and engineering estimates for drilling, injection, and storage, such as well injection rate, $CO_2$ plume area, and injection costs. A depiction of $SCO_2T$'s current data coverage (at the time of writing) for 10 $km^2$ grid-cells is provided in Figure 13, which reports relative storage potential for each geologic formation at each cell. The location, annual injection potential, and estimated total injection and storage cost from $SCO_2T$ were primary inputs into the capture, storage, and transport modeling conducted for this analysis.

Figure 13: Relative $CO_2$ storage potential by geologic formation and 10 $km^2$ grid-cell provided by $SCO_2T$

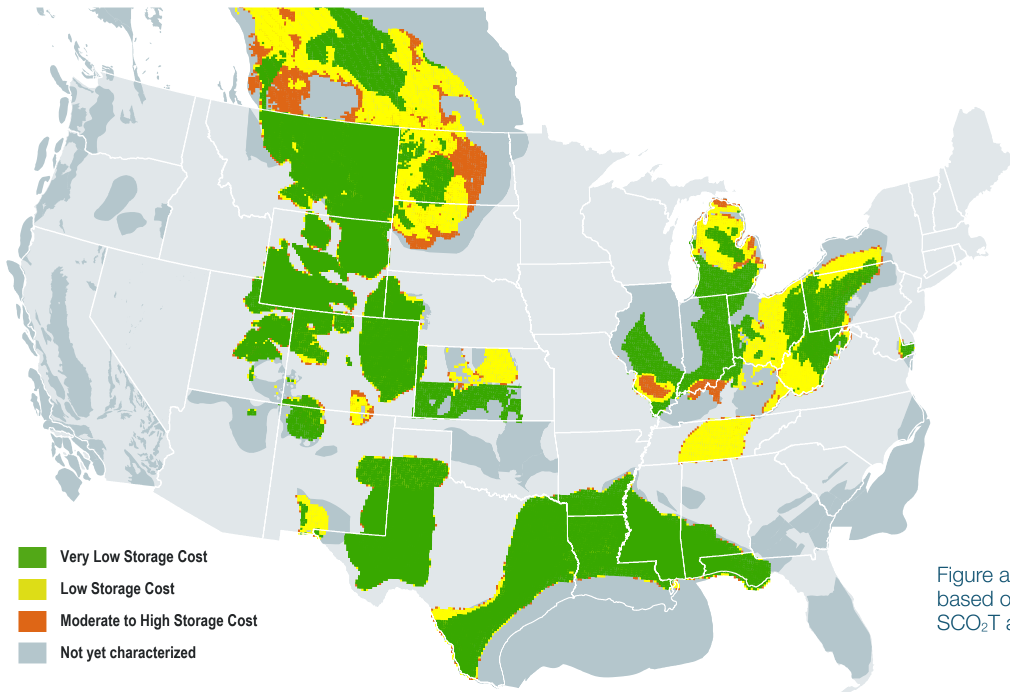



Figure authored by GPI based on data from $SCO_2T$ and NATCARB.

Storage potential and economic criteria for $CO_2$ injection at enhanced oil recovery operations was provided by the Advanced Resources International, Inc. (ARI) proprietary Big Oil Fields Database.[20] This database contains detailed information on over 6,000 oil reservoirs, accounting for over 75% of all oil expected to be ultimately produced in the US through primary and secondary recovery processes. The database reports information on reservoir volume, cumulative oil production to-date of each reservoir, and remaining potential for injection and storage of $CO_2$. Reservoir-specific data also includes key geologic properties and existing field infrastructure and activities that could influence the performance of a $CO_2$-EOR project.

Injection of $CO_2$ into geologic reservoirs provides an opportunity for the permanent storage of tremendous amounts of $CO_2$. Figure 13 shows that deep saline formations with $CO_2$ storage potential exist throughout large areas of the US. Once injected into a saline formation, $CO_2$ is secured by physical and chemical trapping mechanisms. The IPCC reports that well-selected and managed geologic sites are likely to retain over 99% of injected $CO_2$ over 1,000 years. North American $CO_2$ storage potential alone is estimated to be as high as 22 trillion metric tons, which could store nearly 3,500 years of US $CO_2$ emissions.[21]

**North American $CO_2$ storage potential is estimated to be as high as 22 trillion metric tons, enough to store nearly 3,500 years of US $CO_2$ emissions.**

As demonstrated in Figure 14, many potential candidates for carbon capture are co-located in areas of opportunity for geologic storage. This allows capture facilities to permanently store $CO_2$ with minimal transport and may even allow facilities to inject $CO_2$ on or near their existing property. In contrast, many industrial and power facilities are located in areas without significant deep saline formations. Any effort to meet decarbonization goals while maintaining production at these facilities will likely need regional scale transport infrastructure to unlock delivery markets and economic value for captured $CO_2$.

The current Section 45Q tax policy provides an incentive for long-term $CO_2$ storage in both deep saline formations and hydrocarbon basins where EOR operations utilize $CO_2$. The US oil and gas industry has significant current EOR operations that utilize millions of tons of naturally occurring $CO_2$ per year from geologic, rather than anthropogenic, sources. With respect to EOR, Section 45Q can provide a two-fold benefit. Not only does the tax credit create an incentive for EOR operators to switch from geologic $CO_2$ to anthropogenic $CO_2$, it creates a market for source facilities to deliver captured $CO_2$. This is especially helpful for potential source facilities located in areas without nearby deep saline formations. The combination of existing market demand and additional supportive tax incentives for the utilization of anthropogenic $CO_2$ provides near-term economic rationale to build regional infrastructure for the transport of $CO_2$. Because $CO_2$ storage in deep saline incurs a cost for drilling, injection, and monitoring, it may be a difficult economic proposition to build dedicated transport infrastructure without the revenue from sales to EOR operations. Thus, the purchase of $CO_2$ for existing EOR operations can effectively finance regional-scale infrastructure that will later be used by expanded saline storage activity. While the existing Section 45Q tax policy creates the opportunity for this, additional support or low cost financing may be required to plan "supersized" $CO_2$ transport infrastructure with capacity to take on additional volumes in the future, rather than being fit for only a handful of near-term projects.

As shown in Figure 14, major US oil fields are generally clustered in the Texas Gulf and Permian Basin of Western Texas and stretch up through the Western Plains and Northern Rockies. There are also notable clusters in and around Illinois, Ohio, and Michigan. Of these oil fields, only some have sufficient demand for $CO_2$ to create feasible economic conditions to act as potential sites for $CO_2$ storage through $CO_2$-EOR. Oil fields where $CO_2$ demand would likely enable costs of transport and injection to break even or create a profit were selected as storage locations in our modeling scenarios. Overall, large-scale storage in oil fields would require the establishment of sizeable trunk corridors, connecting regions with many $CO_2$ sources to regions with many oil fields and other geologic sinks.

**Maintaining industrial production while meeting decarbonization targets will require regional scale transport infrastructure to unlock delivery markets and economic value for captured $CO_2$.**

## Figure 14. $CO_2$ sources and oil fields with $CO_2$ injection potential

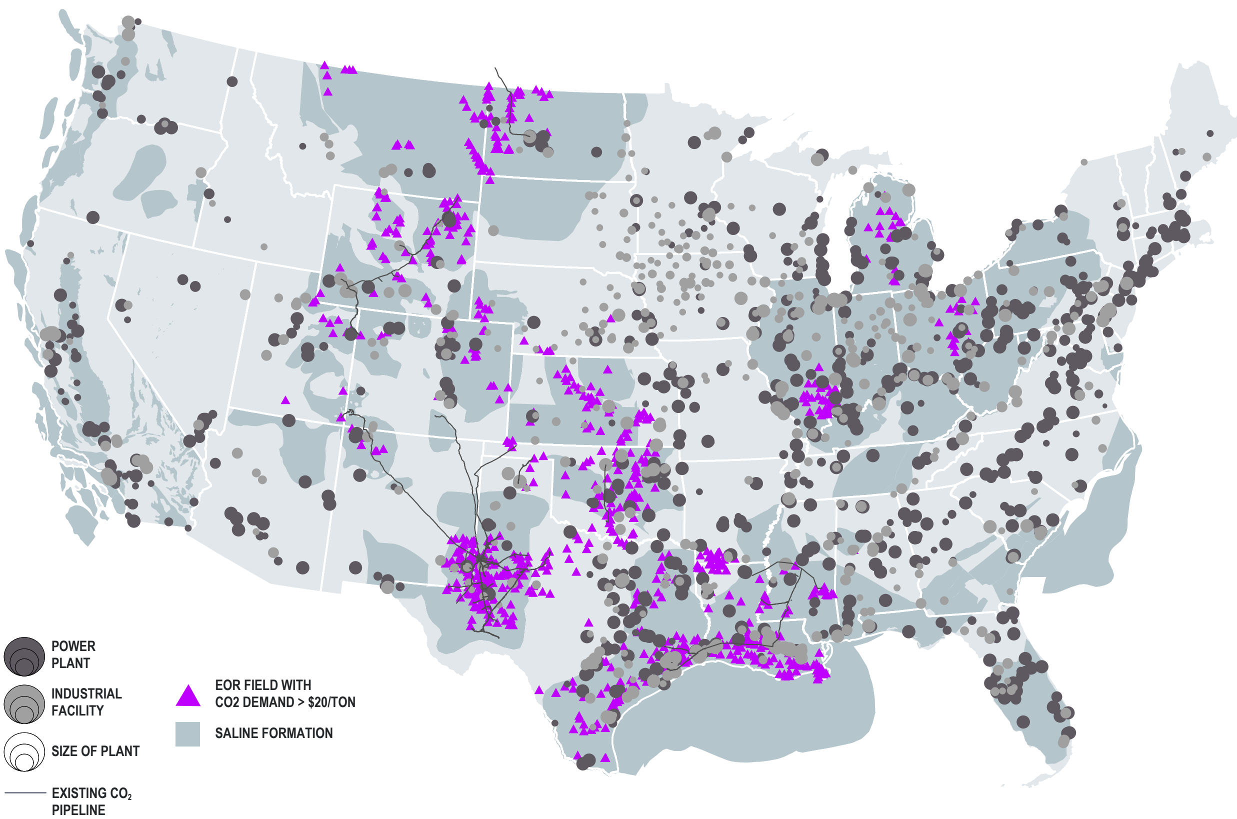



Figure authored by GPI based on results from NATCARB, EPA.

## Table 7. Storage potential in saline formations and EOR operations in study focus states

| State | Saline | EOR |
|---|---|---|
| Alabama | 274,909.7 | - |
| Arkansas | 18,111.3 | 106.4 |
| Colorado | 123,441.8 | 163.2 |
| Illinois | 74,294.9 | 130 |
| Indiana | 59,738.1 | 10.2 |
| Kansas | 32,231.3 | 366.8 |
| Kentucky | 40,460.8 | - |
| Louisiana | 660,992.5 | 1,096.2 |
| Michigan | 41,033.0 | 57.4 |
| Mississippi | 414,287.9 | 98 |
| Montana | 365,441.4 | 184.2 |

Million metric tons storage potential

| State | Saline | EOR |
|---|---|---|
| North Dakota | 132,978.0 | 148.6 |
| Nebraska | 51,580.9 | 28.8 |
| New Mexico | 122,968.2 | 515.4 |
| Ohio | 8,801.0 | 119.4 |
| Oklahoma | 73,191.0 | 1,322.6 |
| South Dakota | 5,047.3 | 2.8 |
| Tennessee | 1,468.3 | - |
| Texas | 1,372,789.7 | 4,875.4 |
| Utah | 84,077.4 | 395.6 |
| Wyoming | 611,222.2 | 522.6 |

Table continued from previous

## Pipeline Routing, Logistics, and Scenario Development: SimCCS

SimCCS, created by Los Alamos National Laboratory in collaboration with Indiana University and Montana State University, is an open-source software tool for designing $CO_2$ capture, transport, and storage infrastructure. This analysis utilized SimCCS 2.0, which was released in January 2018, to determine which power and industrial facilities would participate in an optimized capture network, which locations are best positioned for low cost injection and storage, and importantly, to find the most efficient network to connect $CO_2$ sources to sinks. SimCCS 2.0 integrates economic and geospatial considerations and addresses critical parts of the CCS supply chain simultaneously, identifying key cost savings, revenue streams, and risks. SimCCS minimizes the cost of $CO_2$ transport routes over a cost surface based on numerous layers of geographic information and right-of-way concerns such as urban areas, bodies of water, publicly-owned lands and natural resources, indigenous or tribal lands, and existing infrastructure.

To create an optimized pipeline network, the model finds the shortest paths between all source and storage locations, while minimizing sharp angles in the routes and identifying the least expensive infrastructure to meet user-specified capture goals. The model also allows users to project solutions across multiple time periods, proposing early stage infrastructure development to meet longer term capacity needs.

The US DOE's NETL $CO_2$ Transport Cost Model was used to assess costs of transporting $CO_2$ between sources and sinks.[22] GPI worked with Los Alamos researchers to accurately incorporate cost components from NETL's $CO_2$ Transport Cost Model into SimCCS, allowing the model to use comparative transport network cost estimates in real time while determining routes for $CO_2$ transport.

GPI also used the NETL $CO_2$ Transport Cost Model to calculate in-depth cost results and determine physical characteristics of $CO_2$ transport segments generated by SimCCS. SimCCS reports the length and $CO_2$ capacity of each pipeline, allowing the NETL model to generate feasible diameters and a detailed breakdown of investment required for capital construction, materials, labor, operation, and maintenance. The resulting cost per ton of $CO_2$ transported for each segment is a crucial component in modeling the economics of $CO_2$ capture, transport, and storage, as it indicates the likely transport tariff that a seller or buyer would need to pay in order to deliver $CO_2$ to storage locations. In general, cost per ton of $CO_2$ transported decreased as pipeline diameter increased, given that more $CO_2$ could be delivered with a greater-diameter pipeline.

## Regional $CO_2$ Capture and Storage Transport Networks

To optimize the design of a regional $CO_2$ transport corridor suitable for economy-wide deployment, a series of scenarios were devised that build out capture retrofits over time at industrial and power facilities. The datasets in Table 8 provided a range of configurations for input data in these scenarios. The results from these scenarios were provided in the first summary section of this paper and are discussed in more detail in the following pages.

Table 8. Primary input data sources per scenario

| | CAPTURE | STORAGE | TRANSPORT |
|---|---|---|---|
| NEAR- AND MEDIUM-TERM | Industrial and power facilities within the study region identified as **near- or medium-term opportunities** for capture retrofit.<br>Data source: EPA FLIGHT 2018 screened for economic capture opportunity. | Deep saline geologic formations with estimated **injection and storage costs** of less than $5 per metric ton.<br>Data source: $SCO_2T$, based on NATCARB, RCSP, USGS.<br><br>Petroleum basins: existing operations with **potential demand for $CO_2$ at oil prices of at least $40 per barrel**.<br>Data source: ARI 2018. | Trunk and feeder line **route optimization** and capacity determination performed by SimCCS. **Cost optimization** and calculation performed by SimCCS based on costs published in the NETL $CO_2$ Transport Cost Model.<br><br>Further **cost components and financing considerations** calculated by the NETL $CO_2$ Transport Cost Model based on SimCCS output. |
| MIDCENTURY HORIZON | All US industrial and power facilities with annual $CO_2$ emissions that **qualify for 45Q.**<br>Data source: EPA FLIGHT 2018 screened for 45Q threshold emission levels. | Deep saline geologic formations with estimated **injection and storage costs** of less than $5 per metric ton.<br>Data source: $SCO_2T$, based on NATCARB, RCSP, USGS.<br><br>Petroleum basins: existing operations with **potential demand for $CO_2$ at oil prices of at least $60 per barrel.**<br>Data source: ARI 2018. | |

## RESULTS: NEAR- AND MEDIUM-TERM OPPORTUNITY SCENARIO

As outlined in the sections above and detailed in the methodological appendix of this paper, this analysis identified near- and medium-term opportunities for capture at industrial and power facilities along with likely geologic storage opportunities in deep saline formations and existing EOR operations. Building out shared regional $CO_2$ transport infrastructure will maximize $CO_2$ capture and storage and achieve the scale needed to reach US and international decarbonization targets, while minimizing investment requirements, transport costs, and land use. Los Alamos National Laboratory's SimCCS model was used to identify optimal regional scale transport networks that deliver $CO_2$ from capture facilities to storage locations identified by this analysis, resulting in Figure 15.

**CAPTURE**

Industrial and power facilities within the study region identified as **near- or medium-term opportunities** for capture retrofit.

**STORAGE**

Deep saline geologic formations with estimated **injection and storage costs** of less than $5 per metric ton.

Petroleum basins: existing operations with **potential demand for $CO_2$ at oil prices of at least $40 per barrel**.

**TRANSPORT**

SimCCS mode: **Optimize for maximum capture and storage quantity with minimum transport network distance and land use.** Transport network requires capital investment.

### Figure 15. Optimized transport network for economy-wide $CO_2$ capture and storage

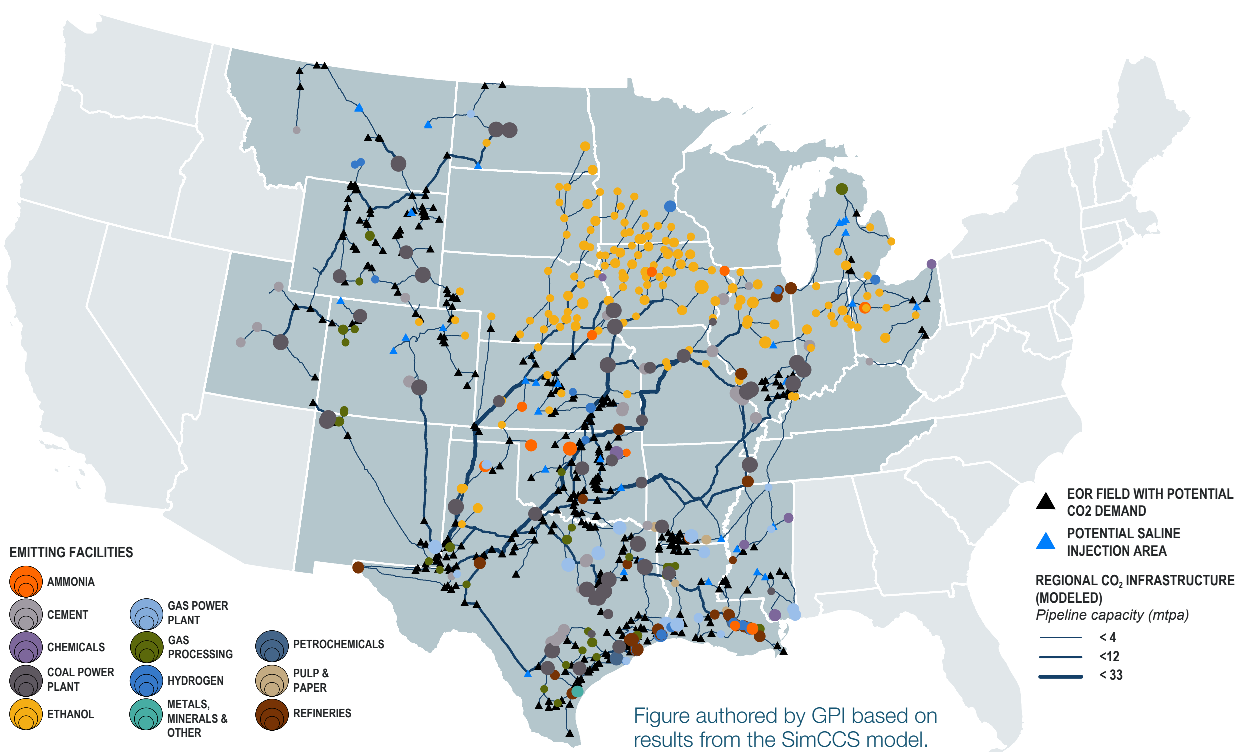



Figure authored by GPI based on results from the SimCCS model.

Table 9. Annual capture and storage quantity by industry: **Near- and Medium-Term Opportunity Scenario**

| Industry | Number of Facilities | $CO_2$ Captured million metric tons |
|---|---|---|
| Ammonia | 14 | 9.8 |
| Cement | 33 | 26 |
| Chemicals | 8 | 4.8 |
| Coal Power Plant | 45 | 124.4 |
| Ethanol | 149 | 36.5 |
| Gas Power Plant | 18 | 17.2 |
| Gas Processing | 35 | 9.7 |
| Hydrogen | 35 | 15.5 |
| Metals, Minerals & Other | 1 | 0.7 |
| Other Power Plant | 1 | 0.5 |
| Petrochemicals | 3 | 4 |
| Pulp & Paper | 3 | 1.1 |
| Refineries | 36 | 30.9 |
| **Total Captured & Stored: 281.2 million metric tons** | | |

Scenario results:

- 281.2 million metric tons of $CO_2$ are captured and stored annually, with $CO_2$ captured from 381 emitting facilities.
- 29,710 miles of $CO_2$ pipeline are built out in this scenario. Several thousand miles of moderate- and high-flow aggregator lines connect facility clusters in the Upper Midwest to storage sites in the Lower Midwest, Gulf, and Western Texas.
- This pipeline network requires 16.6 billion dollars in capital investment, 14.3 billion dollars in project labor costs, and 251.8 million dollars in annual operating and maintenance costs.

Table 10. Pipeline miles by diameter: **Near- and Medium- Term Opportunity Scenario**

| Diameter inches | Length miles | Total Capital Investment million dollars | Project Labor Investment million dollars | Annual O&M Spending million dollars |
|---|---|---|---|---|
| 4" | 4,712 | $1,390 | $1,861 | $39.9 |
| 6" | 6,063 | $1,891 | $2,470 | $51.4 |
| 8" | 8,560 | $3,436 | $3,672 | $72.6 |
| 12" | 5,834 | $4,195 | $2,928 | $49.5 |
| 16" | 2,675 | $2,888 | $1,777 | $22.7 |
| 20" | 1,790 | $2,704 | $1,498 | $15.2 |
| 24" | 59 | $99 | $63 | $0.5 |
| 30" | 16 | $34 | $23 | $0.1 |
| **Total** | **29,710** | **$16,635** | **$14,292** | **$251.8** |

**281.2 million metric tons of $CO_2$ are captured and stored annually from 381 emitting facilities in the Near- and Medium-Term Scenario.**

## RESULTS: HIGH-COST SENSITIVITY SCENARIO

Achieving US economy-wide decarbonization goals will likely require capital investment across numerous sectors and industries. While $CO_2$ transport infrastructure does represent a significant investment, a shared regional-scale transport network will minimize the overall capital expense required. To identify near-term opportunities for the first parts of this regional network, this study ran SimCCS in a strict economic pricing mode in which all infrastructure investment must be paid for by the sale of $CO_2$. Near-term candidates for capture retrofit were provided the option by the model to invest in transport infrastructure to reach distant EOR operations with positive economic demand for $CO_2$ or to store in nearby saline formations at a cost (for injection, storage, and monitoring).

The results of this high-cost sensitivity show two things: First, that there is immediate economic potential for geographically concentrated, low-cost industrial sources in the Midwest (specifically, ethanol facilities) to aggregate their $CO_2$ supply and deliver to storage locations at petroleum basins in Kansas, Oklahoma, and Texas. Second, in areas with sufficient storage potential in deep saline formations, a variety of industries with low and moderate capture costs have economic potential to claim Section 45Q tax credits for local storage in nearby deep saline formations. This is also true for these industries in areas with storage potential in petroleum basins, such as Louisiana, Oklahoma, Texas, and parts of the Rockies.

**CAPTURE**

Industrial and power facilities within the study region identified as **near- or medium-term opportunities** for capture retrofit.

**STORAGE**

Deep saline geologic formations with estimated **injection and storage costs** of less than $5 per metric ton.

Petroleum basins: existing operations with **potential demand for $CO_2$ at oil prices of at least $40 per barrel**.

**TRANSPORT**

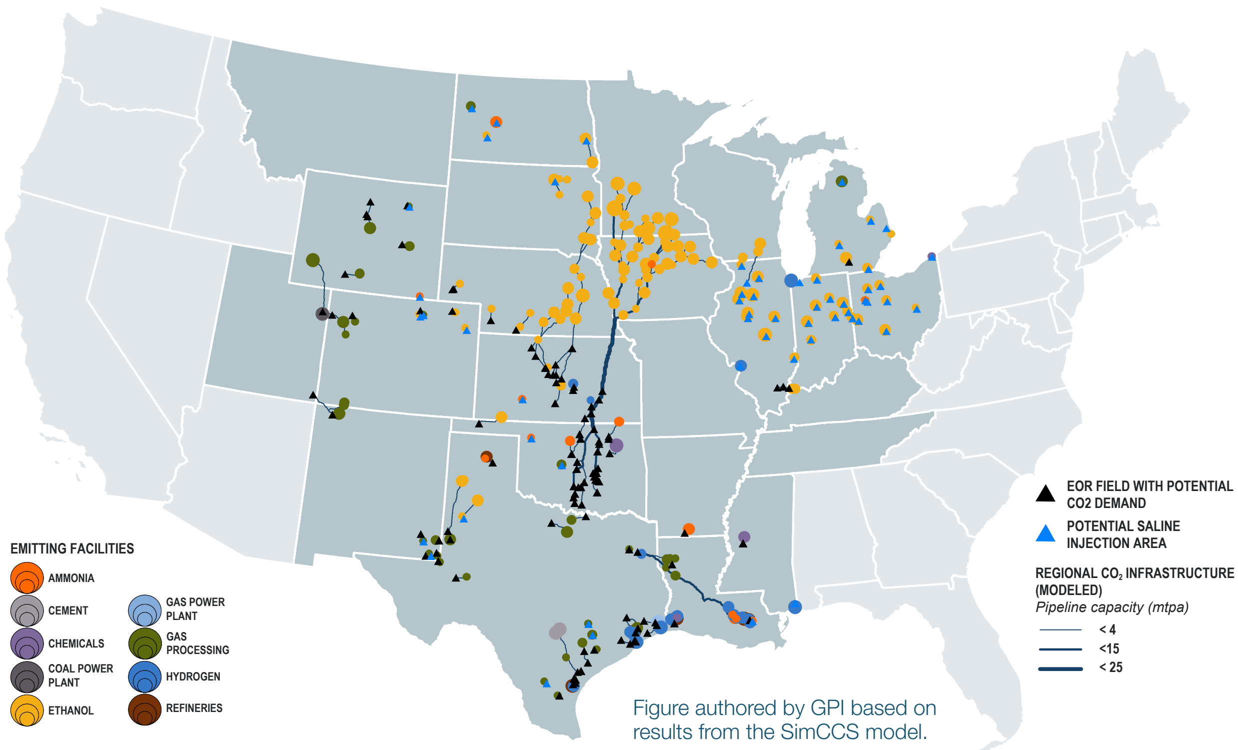
SimCCS mode**: Transport network must be paid for by revenue from sale of $CO_2$.** Capital investment required for transport network is essentially paid for by the capture and storage of $CO_2$ under 45Q.

Table 11. Annual capture and storage quantity by industry: **High-Cost Scenario**

| Industry | Number of Facilities | $CO_2$ Captured million metric tons |
|---|---|---|
| Ammonia | 14 | 2.3 |
| Cement | 2 | 2.3 |
| Chemicals | 5 | 1.5 |
| Coal Power Plant | 1 | 1.6 |
| Ethanol | 121 | 44.5 |
| Gas Processing | 39 | 8.9 |
| Hydrogen | 30 | 12.8 |
| Refineries | 9 | 9 |
| **Total Captured & Stored: 83 million metric tons** | | |

**There is immediate economic potential for low-cost industrial sources in the Midwest, such as ethanol facilities, to aggregate $CO_2$ and deliver to storage locations at petroleum basins in Kansas, Oklahoma, and Texas.**

## Figure 15. High-cost sensitivity with economic break-even




## Scenario results:

- Retrofit of 221 emitting facilities results in 83 million metric tons of $CO_2$ economically captured and stored each year. Ethanol plants account for over half of the total $CO_2$ captured. Hydrogen-producing facilities, refineries, and gas processing facilities are also major capture sources.

- 6,923 miles of $CO_2$ pipeline are developed with short pipeline segments enabling $CO_2$ injection at local saline formations, made economically feasible through 45Q. Several hundred miles of larger trunk lines are also demonstrated to be economically feasible.

- This pipeline network requires 4 billion dollars in capital investment, 3.4 billion dollars in project labor costs, and 58.7 million dollars in annual operating and maintenance costs.

**A variety of industries with low and moderate capture costs have economic potential to claim Section 45Q tax credits for local storage in nearby deep saline formations.**

### Table 12. Pipeline miles by diameter: **High-Cost Scenario**

| Diameter inches | Length miles | Total Capital Investment million dollars | Project Labor Investment million dollars | Annual O&M Spending million dollars |
|---|---|---|---|---|
| 4" | 1,302 | $502 | $541 | $11.0 |
| 6" | 1,709 | $548 | $700 | $14.5 |
| 8" | 1,943 | $807 | $835 | $16.5 |
| 12" | 1,152 | $878 | $579 | $9.8 |
| 16" | 409 | $460 | $274 | $3.5 |
| 20" | 200 | $327 | $168 | $1.7 |
| 24" | 24 | $34 | $25 | $0.2 |
| 30" | 184 | $432 | $251 | $1.6 |
| **Total** | **6,923** | **$3,988** | **$3,372** | **$58.7** |

## RESULTS: MIDCENTURY DECARBONIZATION SCENARIO

Based on the findings of the initial transport network optimization modeling and the following high-cost sensitivity scenario, which identified additional economic potential for $CO_2$ storage in deep saline formations near capture facilities, a final regional-scale network scenario was modeled to optimize capture and transport infrastructure for storage at EOR operations and deep saline formations.

This aggressive saline scenario resulted in a regional $CO_2$ transport network similar to the initial scenario but with expanded storage in saline formations in the eastern parts of the Midwest, Gulf Coast states, and various locations throughout the Rockies. This study used geologic data for deep saline formations from NATCARB and the $SCO_2T$ saline storage database, as detailed in this paper's Study Approach section and the Methodological Appendix. Further geologic characterization of deep saline formations must be performed in order to identify actual injection and storage sites within local areas.

This scenario achieved 669 million metric tons of $CO_2$ capture and storage, enabled by saline storage for an expanded set of 45Q-eligible facilities in addition to the near- and medium-term facilities.

**669 million metric tons of $CO_2$ are stored annually in this scenario with capture from 947 emitting facilities.**

**CAPTURE**

All industrial and power facilities within study region with annual CO2 emissions that **qualify for 45Q**.

**STORAGE**

Deep saline geologic formations with estimated **injection and storage costs** of less than $5 per metric ton.

Petroleum basins: existing operations with **potential demand for $CO_2$ at oil prices of at least $60 per barrel**.

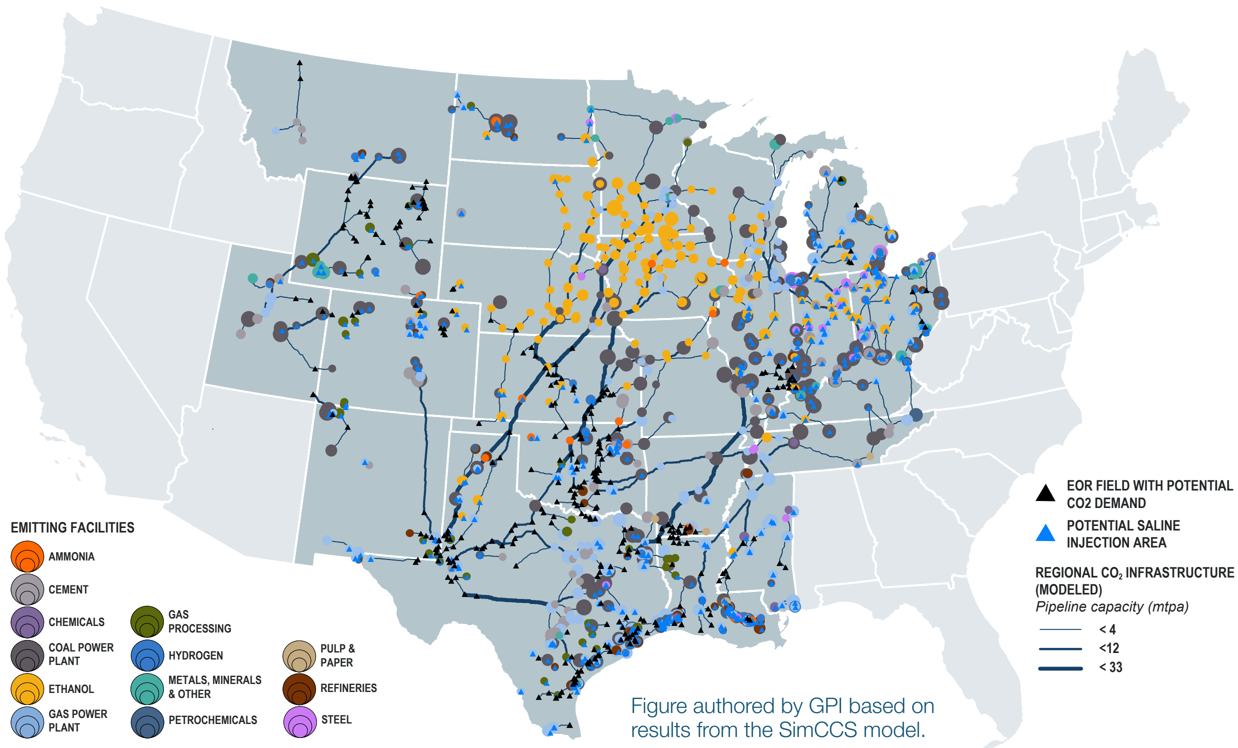
**TRANSPORT**

SimCCS mode: **Optimize for maximum capture and storage quantity with minimum transport network distance and land use.** Transport network requires capital investment.

Table 13. Annual capture and storage quantity by industry: **Midcentury Scenario**

| Industry | Number of Facilities | $CO_2$ Captured million metric tons |
|---|---|---|
| Ammonia | 18 | 2.6 |
| Cement | 75 | 42.5 |
| Chemicals | 9 | 2.3 |
| Coal Power Plant | 200 | 323.9 |
| Ethanol | 166 | 54.7 |
| Gas Power Plant | 249 | 130 |
| Gas Processing | 40 | 9.2 |
| Hydrogen | 44 | 16 |
| Metals, Minerals & Other | 24 | 9.9 |
| Petrochemicals | 31 | 18.4 |
| Pulp & Paper | 5 | 1.2 |
| Refineries | 65 | 34.2 |
| Steel | 21 | 24.1 |
| **Total Captured & Stored: 669.1 million metric tons** | | |

## Figure 16. Expanded storage in deep saline formations and petroleum basins




### Scenario results:

- 669.1 million metric tons of $CO_2$ are stored annually in this scenario with capture from 947 emitting facilities.

- 29,923 miles of pipeline are built out in this scenario. High capacity pipeline routes serve as aggregators for an expanded number of capture sources, accommodating midcentury levels of carbon transport and storage.

### Table 14. Pipeline miles by diameter: **Midcentury Scenario**

| **Diameter** inches | **Length** miles | **Total Capital Investment** million dollars | **Project Labor Investment** million dollars | **Annual O&M Spending** million dollars |
|---|---|---|---|---|
| 4" | 3,740 | $1,937 | $1,668 | $31.7 |
| 6" | 6,580 | $2,426 | $2,765 | $55.8 |
| 8" | 8,376 | $3,561 | $3,623 | $71.0 |
| 12" | 6,385 | $4,377 | $3,211 | $54.1 |
| 16" | 1,923 | $1,986 | $1,283 | $16.3 |
| 20" | 2,202 | $3,388 | $1,845 | $18.7 |
| 24" | 341 | $637 | $363 | $2.9 |
| 30" | 377 | $949 | $515 | $3.2 |
| **Total** | **29,923** | **$19,261** | **$15,272** | **$253.7** |

- Major trunk networks in this scenario connect sources in the upper Midwest to sinks in the Gulf and Western Texas. Smaller pipelines connect many sources to local geologic storage sites.

- This pipeline network requires 19.3 billion dollars in initial capital investment,15.3 billion dollars in project labor, and 253.7 million dollars in annual operating and maintenance costs.

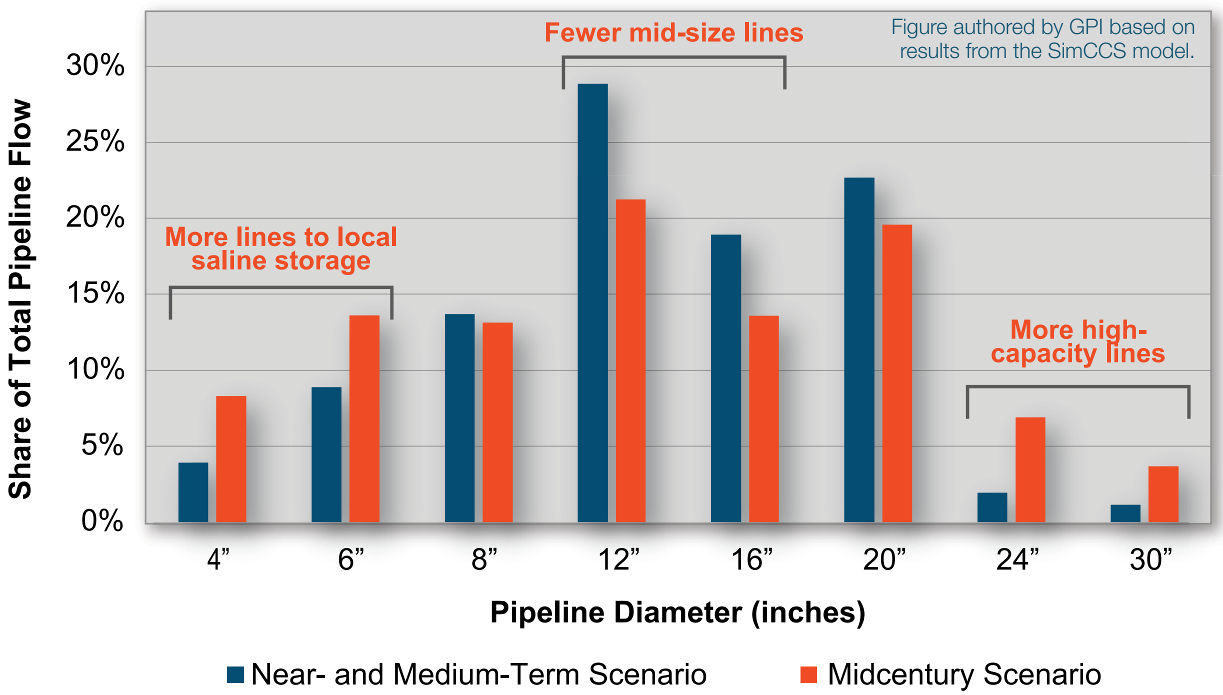
## DISCUSSION OF FINDINGS

The Midcentury Scenario was conceived with a longer planning horizon and was modeled to have expanded access to low-cost storage in deep saline geologic formations and a larger share of industrial facilities for sources of $CO_2$ capture. As a result, the Midcentury Scenario achieved 669 million metric tons of $CO_2$ stored in saline formations and EOR operations — an increase by a factor of 2.38 over the Near- and Medium-Term Scenario's total storage of 281 million metric tons of $CO_2$. One of the most interesting results was that while $CO_2$ storage increased by 138%, the land use required for $CO_2$ transport infrastructure only grew by 0.7% (29,710 miles of pipeline in the Near- and Medium-Term Scenario compared to 29,922 miles in the Midcentury Scenario). This very minimal additional land use impact was achieved through construction of higher capacity trunk lines, as shown in Figure 17.

**While $CO_2$ storage increased by 2.38x, the land use required for $CO_2$ transport infrastructure only grew by 0.7 percent.**

The SimCCS model independently determined that super-sized trunk lines with diameters of 24 inches and 30 inches would be more cost effective under the long-term planning horizon. The capacity to deliver $CO_2$ for each pipeline diameter is explored in Figure 18.

Figure 17: Transport network size for Near- and Medium-Term versus Midcentury Scenario




**Higher capacity trunk lines deliver more $CO_2$ while minimizing land use impact.**

Figure 18: Required pipeline diameter by $CO_2$ transport capacity

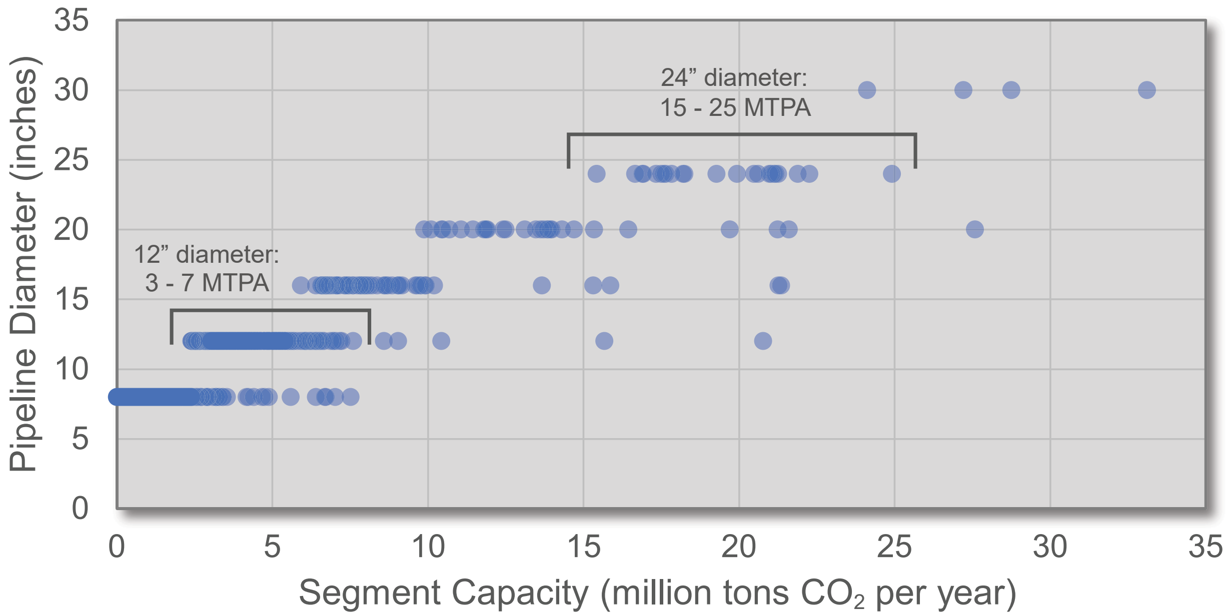



Figure authored by GPI based on calculations performed using the NETL $CO_2$ Transport Cost Model.

There are clear beneficial economies of scale inherent in upgrading $CO_2$ transport networks, especially when considering costs on the basis of per-ton $CO_2$ delivered. While material costs can increase as larger pipeline diameters are required, non-material costs such as labor, equipment, energy, and land use or right-of-way proceedings may not significantly increase. Because the capacity for a transport network segment to deliver $CO_2$ rises with pipeline diameter while the total costs of the infrastructure do not rise as quickly, the effective cost per ton $CO_2$ actually declines with greater diameters.

Scenario results for $CO_2$ transport network infrastructure from the SimCCS model were input into the NETL $CO_2$ Transport Cost model to calculate the cost of each segment of the regional transport network. These results are reported in Figure 19. Small pipelines such as those with diameters of 8 or 12 inches had greater variation and range of costs due to the greater number and diversity of segment lengths. Given that transport infrastructure costs are based on both the diameter (inches) and length (miles) of each component segment, cost is reported here per inch-mile.

Overall, both cost per inch-mile and the resulting transport cost per ton declined as diameter increased. The capital cost of transport infrastructure is significantly affected by financing mechanisms and the cost of capital or required rates of return. This study used default capital and return assumptions published in the NETL model but did observe the decline in capital requirements that would result from low-cost financing or government support through mechanisms such as private activity bonds (PAB) or master limited partnerships (MLP).

## Economies of Scale

**$CO_2$ delivery capacity rises with pipeline diameter while construction costs do not rise as quickly. The effective cost per ton of $CO_2$ declines for infrastructure with greater diameters.**

Figure 19: Infrastructure cost per inch-mile by diameter

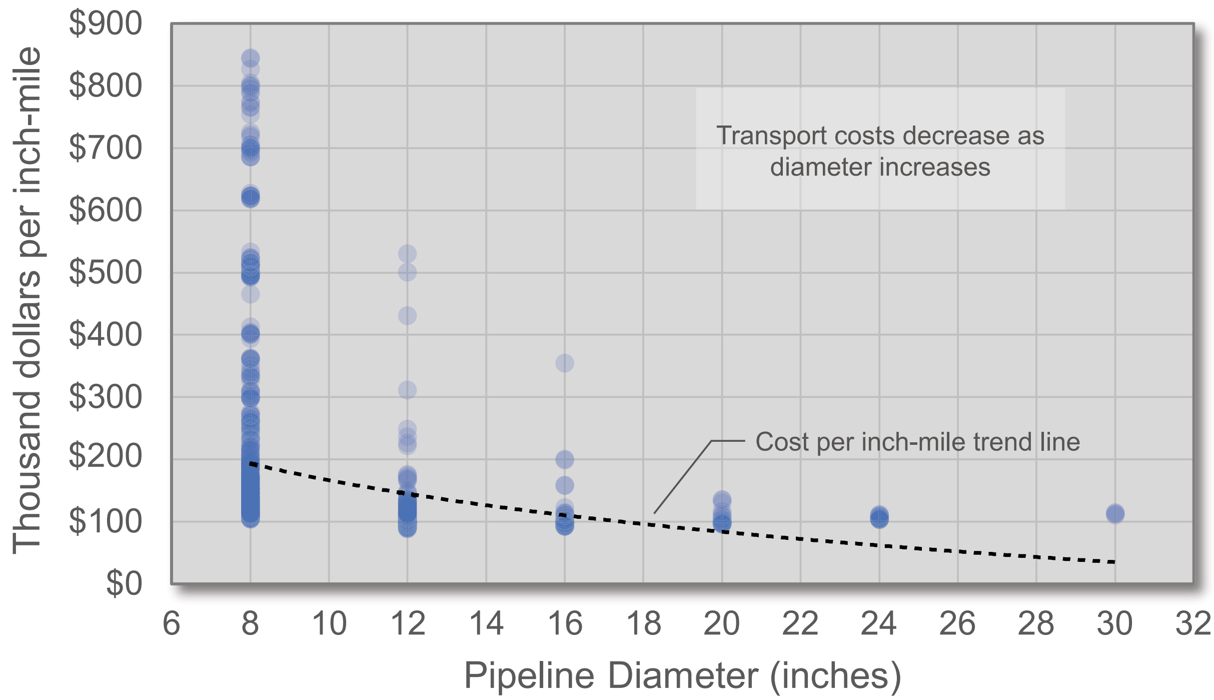



Figure authored by GPI based on calculations performed using the NETL $CO_2$ Transport Cost Model.

Figure 20: Resulting transport tariff by transport network segment diameter

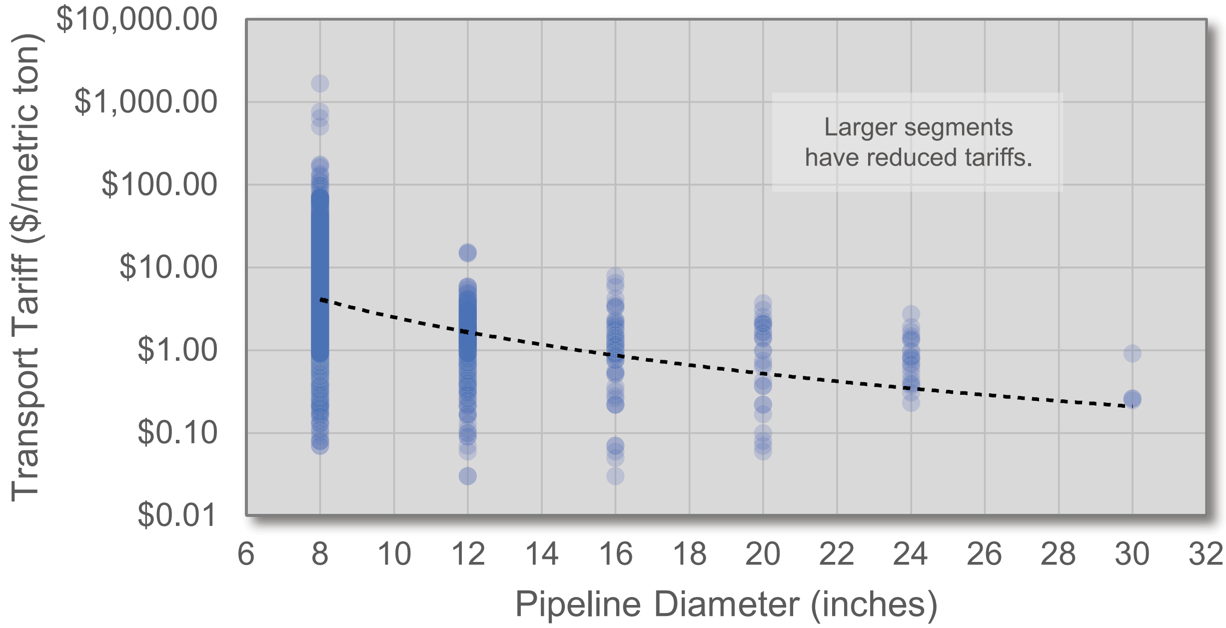
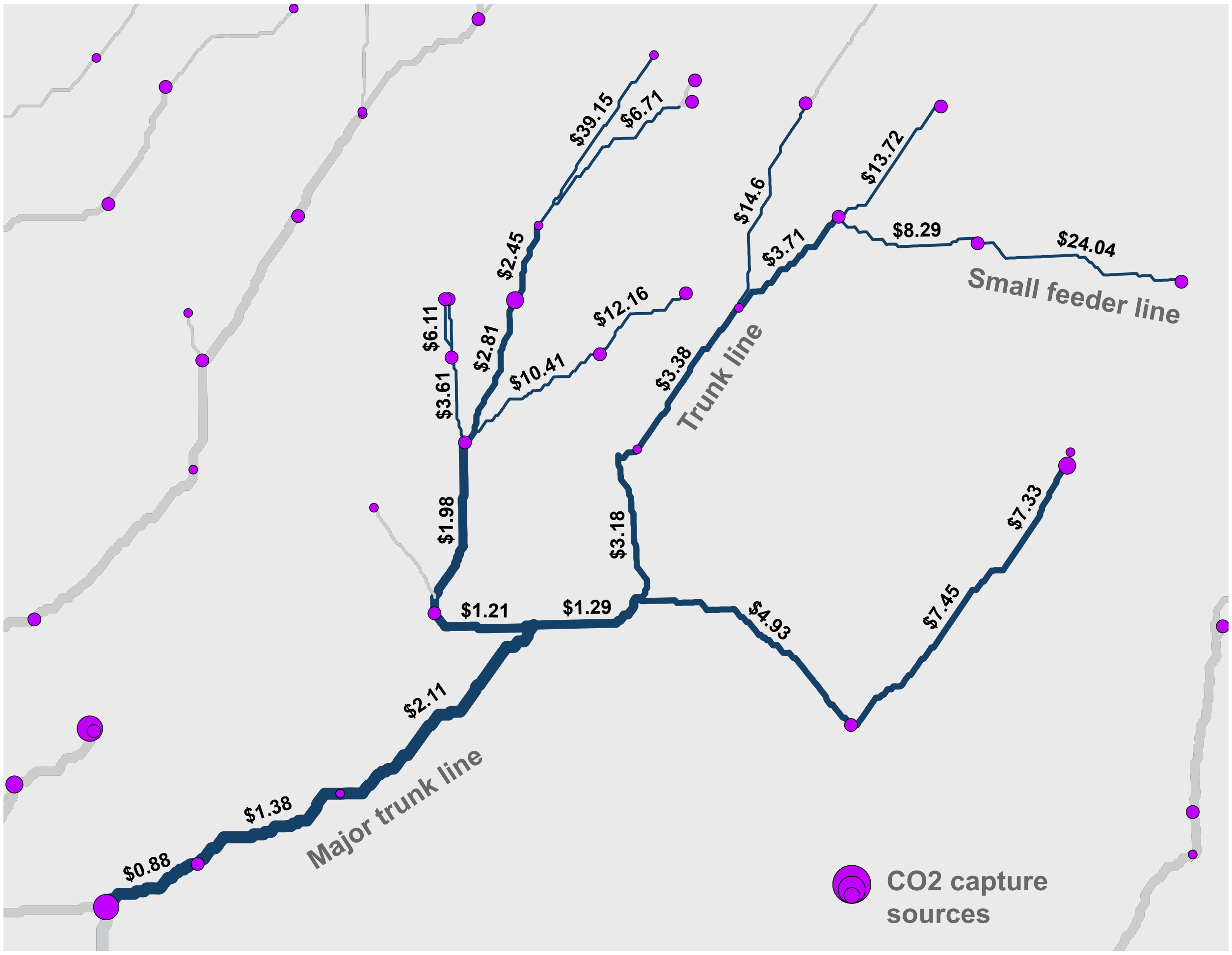



Figure authored by GPI based on calculations performed using the NETL $CO_2$ Transport Cost Model, as modified by McFarlane, Dubois, and Edwards, 2018.

The owner or operator of $CO_2$ transport infrastructure may recoup construction and operating costs by charging a transport tariff on the supplier or purchaser of $CO_2$ that is transported through the network. Theoretical transport tariffs needed to cover the costs of each segment were caluclated using the NETL $CO_2$ transport model in accordance with typical rates of return required by financing and debt. The range of calculated transport tariffs are shown for each pipeline in Figure 20. It is up to the pipeline operator to determine the business model for allocating overall infrastructure costs to users of the infrastructure. The operator may determine a system average cost to charge consistently for all users. Or the route that a quantity of $CO_2$ travels may be determined through accounting of supply and delivery transactions, and the total tariff may be calculated by summing the specific costs of each segment.

Figure 21: Economies of scale: transport tariff ($/ton) by segment of network




Example network section from the Near- and Medium-Term Scenario. Figure authored by GPI based on results from the SimCCS model, with cost estimates calculated by the NETL $CO_2$ Transport Cost model.

**Economies of scale are achieved for major trunk lines with greater diameters while small feeder lines built for individual projects incur much greater per-ton costs. Pipeline operators may charge proportional transport tariffs per segment or determine a system average cost to charge every user.**

In both the Near- and Medium-Term Scenario and the Midcentury Scenario, the required transport tariff for transport network segments with diameters greater than or equal to 12 inches was typically well below $10 per ton. Prices varied widely for smaller segments with diameters of only 8 inches, with some segments well above $10 per ton. These small diameter segments are most often feeder lines that connect individual facilities to a trunk line or to local storage. In cases of local storage, the lower capital cost of short distance pipelines, built by the capture operator rather than a centralized regional network operator, could present a desirable business case that results in capture and storage without requiring transport tariffs paid to a third party. In cases where a small feeder line connects a capture facility to a larger transport network, the resulting cost-per-ton calculation of $CO_2$ delivered along this line may be relatively high depending on the business and tariff model of the network operator.

**While the amount of $CO_2$ stored in the Midcentury Scenario more than doubled from the Near- and Medium-Term Scenario, the total mileage of transport infrastructure required increased by only 0.7 percent.**

As shown in Figure 17, the Midcentury Scenario deployed a greater number of small diameter lines for local storage in saline formations as well as a greater number of large diameter trunk lines for regional transportation. While the amount of $CO_2$ stored in the Midcentury Scenario more than doubled from the Near- and Medium-Term Scenario, the total mileage of transport infrastructure required increased by only 0.7 percent and required capital and labor investments as estimated by the NETL $CO_2$ Transport Cost model increased by only 16.3 percent and 7 percent, respectively.

Table 15: $CO_2$ stored, land use, and investment across primary scenarios

| Scenario | $CO_2$ Stored | Miles of Transport Network | Capital Investment | Project Labor Investment | Annual O&M Spending |
|---|---|---|---|---|---|
| Near- and Medium-Term | **281** million metric tons | **29,710** miles | **$16.6** billion | **$14.3** billion | **$252** million |
| Midcentury | **669** million metric tons | **29,922** miles | **$19.3** billion | **$15.3** billion | **$254** million |
| Impact of Midcentury planning horizon | **x 2.38** more $CO_2$ stored | **+0.7%** | **+16.3%** | **+7.0%** | **+0.8%** |

$CO_2$ capture and transport requires significant capital investment on equipment and infrastructure. These purchases of equipment, services, and labor have positive direct and indirect economic impacts in local communities and contribute to state tax revenues. Multiple studies to measure the economic impact of investment in $CO_2$ capture and transport are ongoing, with results set to be released in 2020 and 2021.

**While capture and transport of $CO_2$ requires capital investment, it can also generate revenue, tax credits, and carbon benefits.**

Despite investment requirements, $CO_2$ capture and storage can also generate revenue, tax credits, and carbon benefits. According to modeling results from Los Alamos National Lab and Indiana University's $SCO_2T$ geologic model, there are abundant opportunities for saline storage at costs of less than \$5 per ton $CO_2$. Meanwhile, the 45Q tax policy provides a credit of \$50 per metric ton $CO_2$ that is stored in deep saline formations. For $CO_2$ injected into petroleum basins at EOR operations, 45Q provides a credit of \$35 per metric ton. According to statements by participants of the Regional Carbon Capture Deployment Initiative and data in scientific literature and industry reports, there currently exists a market for the purchase of $CO_2$ at a typical price of \$20 per metric ton.[23,24] At the current level of credit provided by 45Q, while assuming a \$5 per ton storage cost for saline and a market price of \$20 per ton for $CO_2$ used in EOR, the Near- and Medium-Term Scenario could potentially generate \$16.1 billion in revenue annually, while the Midcentury Scenario could generate \$32.7 billion.

Table 16: Potential revenues and credits for stored $CO_2$

| Scenario | Annually | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | 45Q Tax Credit | | | |
| | EOR Storage | Saline Storage | Saline Cost | Saline | EOR | $CO_2$ Sale to EOR | Total Net Revenue |
| Near- and Medium-Term | **262** million metric tons | **37** million metric tons | **\$156** million | **\$1.9** billion | **\$9.2** billion | **\$5.2** billion | **\$16.1** billion |
| Midcentury | **255** million metric tons | **414** million metric tons | **\$2.1** billion | **\$20.7** billion | **\$8.9** billion | **\$5.1** billion | **\$32.7** billion |

There are many factors that must be considered when observing system-wide economic feasibility and establishing a revenue model to pay for the capital investment required by capture equipment retrofits and transport infrastructure. Figure 22 explores the relationship between cost of capture and potential revenue from storing $CO_2$. The economic gap for relatively higher cost capture sources can be bridged by a number of mechanisms related to regional coordination, finance, and public policy.

The true monetization of the 45Q tax credit, its transferability between capture and storage entities, as well as its extension past current expiration schedule, are crucial issues for the effectiveness of 45Q in the future years of these scenarios. For saline storage, local geologic characterization must occur in order to site actual injection locations for low cost storage that is safe, secure, and permanent. For transport infrastructure, a regional network will require coordination between states, possibly coordination between multiple pipeline owners and operators, and long-term planning of likely capture and storage locations to determine routes and expected capacity requirements. A transport network built only with near-term projects in mind will require greater land use and induce higher costs on a per ton basis than a regional network planned with a longer time horizon.

## Figure 22: Closing the cost gap for carbon capture and storage

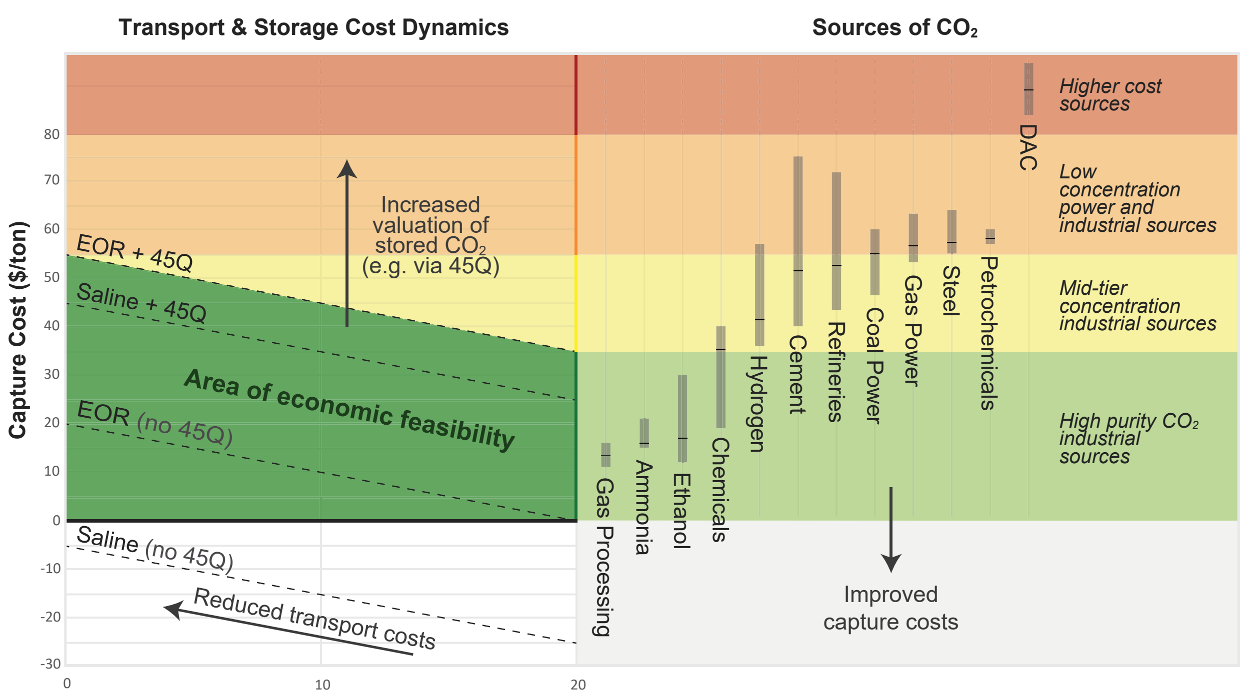



Figure authored by GPI.

**Capture costs** will decrease with research & development, technology deployment learning curve, direct pay, and low-cost financing.

**Transport cost** will decrease with regional coordination, long-term planning, supersizing, direct pay, and low-cost financing.

The economic valuation of **stored $CO_2$** will grow through enhancement of 45Q and other long-term policy and market mechanisms.

The cost of capital or debt and required rates of return have a significant impact on the resulting cost per ton of $CO_2$ across capture, transport, and storage. In today's economic and policy context, there may exist a gap between expected revenues and the cost of capture for privately funded retrofit projects at industrial and power facilities that produce relatively low concentration $CO_2$ emissions. It may not be feasible for such facilities to decarbonize without supportive policies that provide low-cost financing, reductions in capture costs through greater deployment and engineering learning, or an increased valuation of stored $CO_2$. There are a number of state and federal policies and actions that can help reduce the cost of $CO_2$ capture and storage (see Figure 23).

**The cost of capital or debt, and required rates of return have a significant impact on the resulting cost per ton of $CO_2$ across capture, transport, and storage.**

The willingness of oil field operators to purchase $CO_2$ for enhanced oil recovery is intrinsically linked to the market price of the oil they produce. Higher oil prices may result in higher market demand for $CO_2$. Captured anthropogenic $CO_2$ must compete with natural geologic $CO_2$ in the existing marketplace, and thus it is not likely to be sold at prices greater than $20 per

Figure 23: Policies and strategies to reduce cost of carbon capture and storage

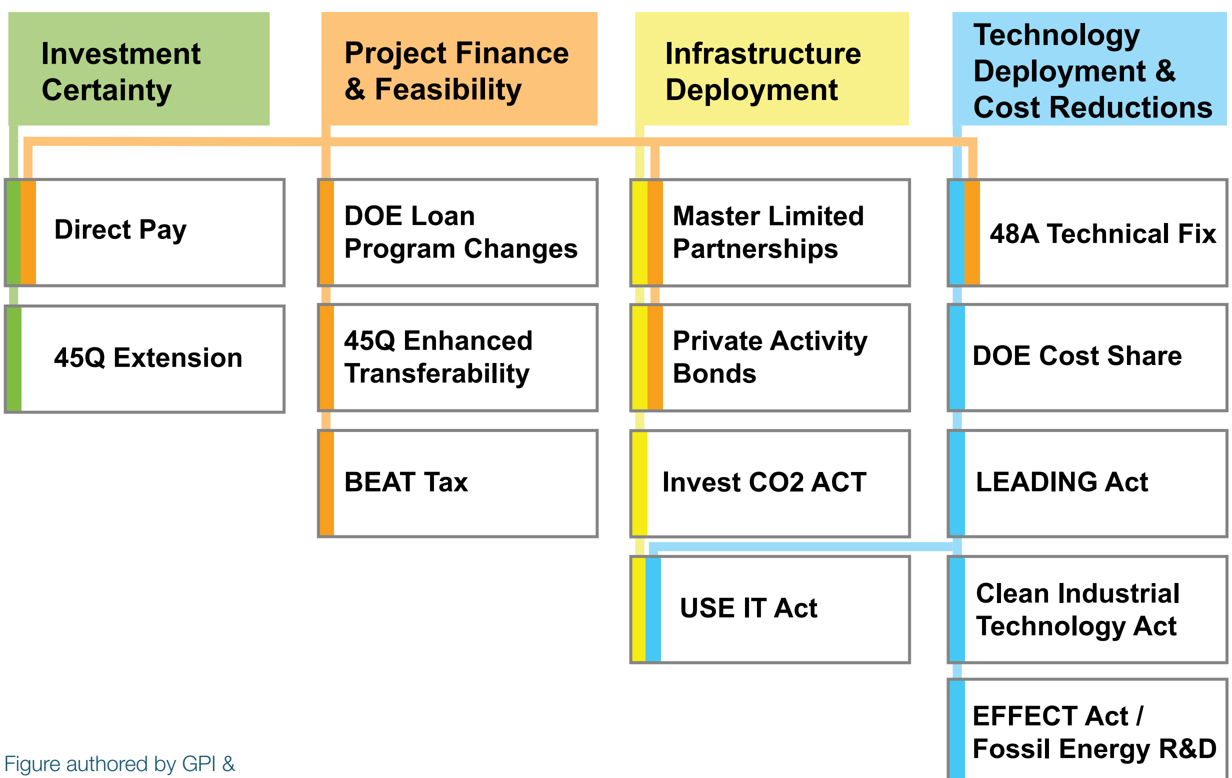



Figure authored by GPI & Carbon Capture Coalition.

metric ton. As explained above, aside from the generation of 45Q tax credits, saline storage requires spending on injection and long-term monitoring, resulting in almost no revenue alongside a range of storage costs depending on specific geology. The externalities of $CO_2$ emissions and a potentially higher valuation of stored $CO_2$ in the future are not priced into today's market. As the US approaches midcentury and efforts to meet decarbonization goals escalate, however, it is likely that society and the economy will establish greater value for permanently stored $CO_2$, resulting in higher revenues for these projects.

Economy-wide decarbonization will require capital investment, not all of which may pay for itself or break even purely under today's market conditions and financing requirements. There exist a number of policies and strategies that can help bridge the gap between costs of capture, revenues, and storage or transport costs. Federal and state support can play a role in reducing the costs of technology and infrastructure and creating an environment of increased investment certainty and financing feasibility.

**For transport infrastructure, a regional network will require coordination between states, possibly coordination between multiple pipeline owners and operators, and long-term planning.**

**Meeting decarbonization goals by midcentury will require $CO_2$ capture and storage at orders of magnitude higher than what is occurring today. Meeting these goals will likely require economy-wide deployment of $CO_2$ capture for industrial activities.**

## CONCLUSION

The research and modeling conducted here focused on the scale, design, and logistics required to plan $CO_2$ transport infrastructure to maximize the rate of capture from industrial and power facilities and maximize storage in geologic formations. This study identified the fleet of industrial and power facilities that present relatively low-cost opportunities for strategically targeted capture retrofit. This study was not focused on identifying which industrial facilities present capture projects that financially break even and produce net positive revenue in today's economic and policy environment.

Assessments of industrial and power sector emissions conducted both within the United States and internationally indicate that meeting decarbonization goals by midcentury will require $CO_2$ capture and storage at orders of magnitude higher than what is occurring today. Meeting these goals will likely require economywide deployment of $CO_2$ capture for industrial activities where switching to renewable energy still leaves significant process emissions unrelated to electricity or natural gas use. This study found that transport costs are a determining factor in the economic feasibility of linking capture facilities with storage locations under today's economic and policy conditions, and that planning this transport infrastructure on a longer time horizon can potentially achieve higher rates of capture and storage at lower transport costs. Utilizing a coordinated regional network will bring down transport cost and create infrastructure to help reduce the economic gap for sources that are not economic in the near term.

**This study found that transport costs are a determining factor in the economic feasibility of $CO_2$ capture and storage under today's economic and policy conditions. Planning transport infrastructure on a longer time horizon can achieve higher rates of capture and storage at lower transport costs.**

There already exists an active market for the purchase of $CO_2$ for injection and utilization in petroleum producing regions of the US. The $CO_2$ being sold and utilized in this market originates primarily from natural geologic sources, even while nearby industrial and power facilities emit large quantities of anthropogenic $CO_2$ into the atmosphere. The federal 45Q tax credit essentially creates a pathway to bring low- and mid-cost industrial sources into this existing market for $CO_2$ utilization and associated geologic storage, while providing a market for saline geologic storage for the first time. As demonstrated by the High-Cost Sensitivity Scenario, as well as the full set of facilities that did not connect to transport infrastructure in other scenarios, there still exists a very large subset of $CO_2$ capture sources where relatively high capture costs present challenging economics. Achieving economic feasibility for these facilities will require a combination of cost reduction through technology advancement and deployment, low-cost financing and supportive state and federal policies, a renewal and expansion of the 45Q tax credit, or other policies and marketplaces that would establish growing revenues for capture or pricing of $CO_2$.

**Improved economic feasibility will require cost reduction through technology advancement and deployment, low-cost financing and supportive state and federal policies, and renewal and expansion of the 45Q tax credit.**

This study has shown clear opportunities for wide-spread capture at relatively low estimated costs throughout a study region that included the Midwest, Rockies, Plains, Gulf Coast, and Texas. The resulting model of optimized regional-scale $CO_2$ transport infrastructure presents feasible pathways to reach national and international goals and demonstrated what feasible large-scale carbon capture infrastructure buildout could look like. The 45Q tax credit for carbon capture clearly helps create a marketplace where supply of $CO_2$ can meet existing demand, especially for industrial sources of medium and high purity $CO_2$ emissions. In power plants and some industrial facilities with relatively low concentration $CO_2$ emissions, such as cement and steel production sites or petroleum refineries, estimated capture costs still present difficult economics depending on transportation costs, distance to storage location, and the cost of $CO_2$ storage, even with the existing 45Q tax credit.

The difference in build-out of $CO_2$ transport infrastructure in the Near- to Medium-Term Scenario and the High-Cost Sensitivity Scenario shows that there is still a gap in pure break-even economic equilibrium: a regional scale $CO_2$ transport network will require capital investment that will not necessarily be paid simply through the sale of $CO_2$ at $20 per ton combined with the value of tax credits in the current 45Q program. The transport networks modeled here maximize the rate of $CO_2$ capture and storage across the power and industrial sectors while minimizing the cost and land use of transport infrastructure. In reality, $CO_2$ transport infrastructure may more likely be built out in a piecemeal fashion, linking single facilities or a small group of projects to a single storage location. This may result in $CO_2$ infrastructure that is not of sufficient capacity to meet the scale of $CO_2$ capture and storage required by midcentury decarbonization targets. This infrastructure would need to be replaced in the future or an abundance of additional infrastructure would need to be built, costing more and having a greater land use impact than a regional system built through coordinated planning.

**This study has shown clear opportunities for wide-spread capture at low costs throughout the Midwest, Midcontinent, Rockies, Northern Plains, Gulf Coast, and Texas.**

If the US is to significantly decarbonize the industrial and power sectors, as well as create a marketplace that allows for direct air capture facilities to help achieve net-zero or negative carbon emissions, then planning and coordination must occur in the near term to begin building regional-scale transport networks for economy-wide deployment of carbon capture and storage. By midcentury, local, national, and international climate action and the need to drive down the societal costs of carbon emissions will likely create natural economic incentives that enable $CO_2$ capture at industrial and power facilities, in addition to direct air capture facilities, that today seem relatively expensive.

**Near-term planning and coordination of regional-scale infrastructure will enable significant decarbonization of the industrial and power sectors while creating a marketplace for direct air capture of $CO_2$ will require.**

**Economy-wide deployment of carbon capture and storage will help achieve net-zero or negative carbon emissions in the US.**

Developing solutions in the near term to address logistical issues such as inter-state $CO_2$ transportation corridors, interconnected pipeline networks operated or shared by multiple private entities, and state and federal support for future-proofing pipeline capacity through "super-sizing" will drastically reduce costs as well as land use and environmental impact of $CO_2$ transport infrastructure. Achieving national goals will require broad scale coordinated vision and action. This analysis provides a framework for coordinated regional infrastructure that can help define that vision.

Momentum is building for carbon capture in the US, as evidenced by bipartisan policy developments at the federal and state levels. As part of the Bipartisan Budget Act of 2018, Congress passed legislation originally introduced as the FUTURE Act with broad bipartisan support to expand and reform Section 45Q of the US tax code. The expansion of Section 45Q has created a more favorable national policy landscape for carbon capture in the US than ever before, increasing the financial viability of carbon capture projects and extending eligibility to industries that were previously excluded from accessing the benefits of 45Q.

This congressional action has significantly elevated carbon capture on the national energy agenda and provides an essential policy driver for commercial deployment of carbon capture and storage technology.

Additional congressional action is now needed to broaden the suite of policies supporting carbon capture deployment, including incentives for $CO_2$ transport infrastructure, just as Congress has provided a broad portfolio of policies that have successfully fostered commercialization of wind, solar and other low and zero-carbon technologies in the marketplace.

Going forward, state policy can also play an important role in complementing 45Q and other federal policies to help carbon capture projects bridge cost gaps and achieve financial feasibility. State policies providing incentives for carbon capture, facilitating the development of $CO_2$ transport and storage infrastructure, and implementing energy portfolio requirements can all make carbon capture more economically feasible at local and regional levels.

# ANALYTICAL OVERVIEW AND FULL DISCUSSION REFERENCES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# **Appendix:** Industrial and Power Facility Screening and Capture Cost Estimation Methodology

## INTRODUCTION

This analytical methodology includes an overview of how to identify potential facilities for carbon capture retrofit and quantify target capture volumes at such facilities. First, this methodology discusses the identification of promising retrofit candidates based on characteristics of the host emitter (the emitting facility potentially hosting capture equipment). Key criteria include the scale of emissions from the facility, economic health of the emitting facility, and availability of capture technology appropriate to the industry. The process used to identify potential candidates for carbon capture retrofit and estimate potential $CO_2$ capture quantities from these facilities consists of two primary steps:

1. Sort EPA FLIGHT data[1] to eliminate industrial facilities that emit less than 100,000 MTPA $CO_2$ and power facilities that emit less than 500,000 MTPA $CO_2$, as those are the minimum emissions levels required to qualify for the Section 45Q carbon capture tax credit.

2. Assess each of those large emitters for suitability for capture. This included categorizing the industry of each emitter and identifying emissions generated by specific energy production or industrial, manufacturing, and refining processes within each facility that have the best potential for carbon capture.

Second, this methodology discusses estimation of capture cost at particular facilities. This entailed applying the best available engineering studies and expert consensus on capture cost in the relevant industry while also considering information from public sources and local knowledge.

## IDENTIFICATION OF RETROFIT CANDIDATES BASED ON THE EMITTING FACILITY

This section describes how potential candidates for carbon capture retrofit were isolated by identifying $CO_2$ emissions that could be captured at reasonable cost within particular industries, sites, and processes. This analysis focused on the likeliest candidates for retrofit within certain industries: ethanol, natural gas processing, ammonia, hydrogen, steel, cement, oil refining, chemicals, petrochemicals, pulp and paper, coal power, and natural gas power.

### Analysis of Emissions Data

Reports filed with the US EPA were examined to classify each facility by industry and identify emissions for the manufacturing and industrial processes of interest within each facility. In some cases, a closer examination was needed to discern specific industry classifications from within broad US EPA GHG Reporting Program (GHGRP) industry categories. For example, special attention was given to assess variation among individual facilities in the steel industry and power industry:

- The “Iron and Steel” industry reports under a broad EPA GHGRP industry category. This category includes a wide variety of emitters such as standalone coke batteries, electric-arc furnace mini-mills, and specialized alloy foundries that do not emit large volumes of concentrated $CO_2$.

- Similarly, the electric power generation industry reports under an industry category that includes many emitters that are likely not feasible candidates, such as banks of simple cycle gas combustion turbines that operate only rarely and thus are uneconomic for carbon capture retrofit.

For ethanol refineries, which are a high-purity and low-cost source of $CO_2$ from biologic fermentation emissions, it was necessary to rely upon non-EPA estimates of annual ethanol production in order to calculate total $CO_2$ emissions. At an ethanol plant, emissions that are created by combusting fuel beneath a fermentation vat are reported as Stationary Emissions under the General Stationary Fuel Combustion Sources subpart, but the fermentation emissions themselves are not reported. Data tables of US ethanol facilities, their location, and annual production capacity are published online by the Nebraska Department of Environment and Energy and by the Renewable Fuels Association, and were relied upon to calculate $CO_2$ emissions from biologic fermentation at ethanol plants for this analysis.

Detailed emissions reports were parsed for the processes of interest at each facility. This was especially true in the iron and steel industry and the oil refining industry.

- Within the iron and steel industry, the literature shows that only the particular vent stacks related to the combustion of blast furnace gases are of sufficient size and concentration to be of interest in a near-term economically-driven analysis. Hence, for a steel mill such as Arcelor Mittal's Burns Harbor plant in Indiana, overall reported emissions are 10.1 million tons per annum (MTPA), but blast furnace gas combustion contributes only 3.2 million MTPA out of the total.
- Within the oil refining industry, hydrogen manufacturing is separated and easy to identify within the GHGRP reporting information, with the remaining emissions of prime interest being related to the combustion of coke deposits on catalyst materials used in fluidized catalytic cracking units (FFCUs). Hence, for a larger oil refinery such as the Wood River Refinery in Roxanna, Illinois, total emissions are 4.2 million MTPA of which FCCU emissions represent only 0.9 million MTPA and hydrogen manufacture another 1.0 million MTPA.

Third, once having identified emitters of interest and the manufacturing processes of interest, it was necessary to be quite careful about the idiosyncrasies of the way in which the same physical process might be reported in two different industries. As an example, emissions from hydrogen plants—i.e., Steam Methane Reformer (SMR) units—can be parsed into "combustion emissions" and "process emissions". Combustion of purchased natural gas in stoves beneath the reformer vessels creates "combustion emissions", whereas emissions from any elemental carbon originally injected into the reformer vessels create "process emissions". The low-cost capture opportunities are found in a portion of the process emissions.

- However, if the SMR is used to make hydrogen as a final product, either when owned by an oil refinery (known as a "captive hydrogen plant") or owned by an industrial gases company, both the process emissions and combustion emissions are listed under subpart P.

- The opposite is true when an SMR is used to make hydrogen as an intermediate feedstock in an ammonia plant. In that case the ammonia producer is supposed to parse the SMR emissions, putting the process emissions under subpart G (ammonia) and the combustion emissions from the SMR under subpart C (stationary combustion).

## Analysis of Power Plant Generating Units: Right-Sizing Capture Equipment

Especially within the power industry, it was critical to identify not only particular generating units of interest but the size of the carbon capture unit that could economically be applied against the emissions of each generating unit. The ABB Ability Velocity Suite database was relied upon to accomplish this task.[2]

Sometimes it is relatively easy to identify a power plant for capture purposes (e.g., if an emitter is a single coal power plant unit operating by itself at a single site). Far more often, there may be multiple coal power plant generating units or multiple natural gas combined cycle power plant configurations operating at a single site. It is not uncommon to have several coal power generating units and several natural gas generating units at the same site.

Among units at a site, it is important to identify the generating units that are relatively new, relatively efficient, and are not likely to be shut down because of excessive emissions of conventional criteria pollutants such as ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and nitrogen dioxide.

Moreover, even taking a single generating unit, e.g., a 600 MW nameplate coal power unit, the question arises as to how big the carbon capture equipment should be. Should the carbon capture equipment be large enough to capture ~90% of emissions when the plant is running at the full 600 MW capacity? The coal plant may only rarely be running at the full 600 MW level. The alternative is to capture ~90% of emissions from the amount of stack gases produced when the plant is operating at its most typical output level—for instance at 200-250 MW if the plant is frequently turned down to minimum operating levels during off-peak hours.

### Carbon capture retrofit equipment sizing example

Figure 1 shows hourly emissions from an existing coal power facility. The y-axis is short tons of $CO_2$ emitted per hour, ranked from low-to-high over 8760 hours (x-axis). The graph shows that a treatment module (or train) that can treat exhaust gases containing 220 short tons per hour of $CO_2$ would run at a 92% capacity factor. One could install a second, incremental 360 short tons per hour train to allow the treatment of total maximum emissions of 580 short tons per hour. However, the second train would only run at 57% capacity factor.

Since the 2nd train has similar capital expense per installed metric tons of capture capacity but operates less frequently, its effective capture cost rises. If the 1st train had a capture cost of $60/MT, the 2nd train would have a capture cost of $84/MT. The $60/MT cost estimate includes $21/MT for fuel, electricity, and solvent, with remaining $39/MT for O&M and financing expenses that vary directly with the original capital expenditure (capex). The 2nd train's capacity factor is only 62% of the 1st train's capacity factor (0.57/0.92). As such, the capex related cost per metric ton would rise to \$39/MT / 0.62 = \$63/MT, which plus \$21/MT for the other costs, equals \$84/MT. With a \$35/MT tax credit, and if $CO_2$ could garner a sales price from enhanced oil recovery of \$30/MT for a total of \$65/MT in revenue, the 1st train may be economic.

The 2nd train has virtually no chance of being economic under that incentive and revenue picture. This example helps demonstrate why this analysis did not by any means treat all technically capturable emissions as being economically capturable.

Figure 1. $CO_2$ emissions from an example emitting facility

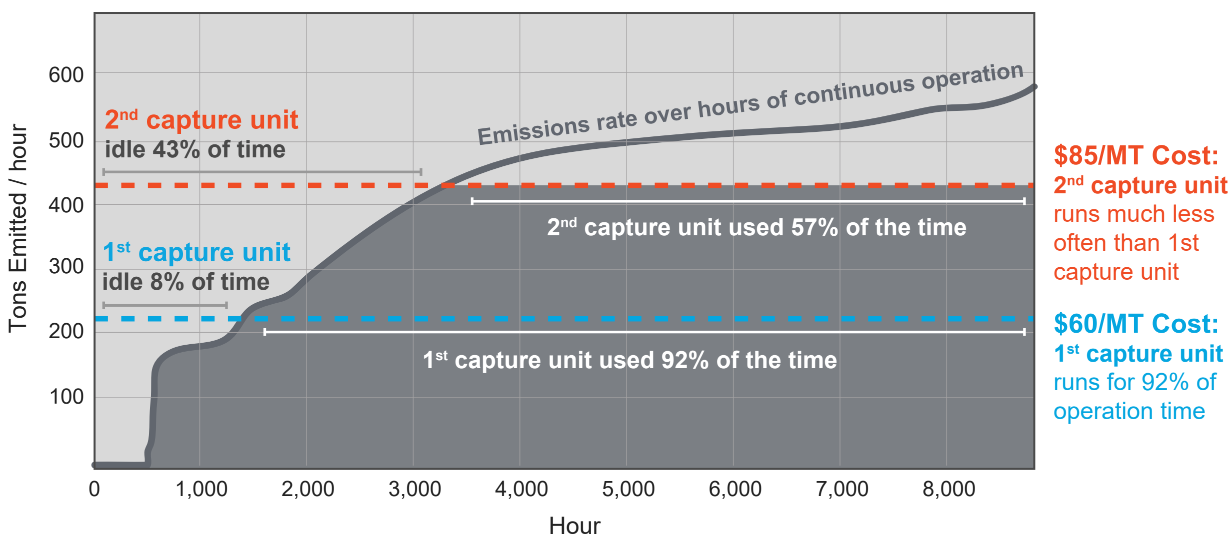



Figure authored by GPI based on data from ABB Ability Velocity Suite.

# DETERMINATION OF THE CARBON CAPTURE COST

The three major cost components for a carbon capture project are (i) annual cost of repaying lenders/investors of funds for the original project construction, (ii) fixed and variable operating costs (excluding energy), and (iii) energy costs, comprised of electricity to run machinery and fuel combusted for steam production.

Table 1: $CO_2$ purity vs capture cost estimate by industry

| $CO_2$ Purity | Concentration of captured $CO_2$ | Main Equipment Needed | Industry | Average Estimated Cost $/ton | Range of Cost Estimates $/ton |
|---|---|---|---|---|---|
| High | Pure $CO_2$ | Compression & dehydration only | Gas Processing | $14 | $11 - $16 |
| | | | Ethanol | $17 | $12 - $30 |
| | | | Ammonia | $17 | $15 -$21 |
| Medium | 16 – 50% | Amine $CO_2$ separation equipment plus compression | Chemicals | $30 | $19 - $40 |
| | | | Hydrogen | $44 | $36 - $57 |
| | | | Refineries | $56 | $43 - $68 |
| | | | Cement | $56 | $40 - $75 |
| | | | Steel | $59 | $55 - $64 |
| | | | Petrochemicals | $59 | $57 - $64 |
| Low | ~13 – 15% | | Coal Power Plant | $56 | $46 - $60 |
| | ~4% | | Gas Power Plant | $57 | $53 - $63 |

## Cost of Capital Expenditures for Equipment

In general, repayment of upfront capital costs represents the majority of total cost per metric ton captured for carbon capture projects. While the original expense of building a carbon capture system is incurred before the first metric ton is captured, the subsequent payments to reimburse lenders and equity investors take place each year over the life of the equipment. The total upfront costs are associated with total annual financing payments for the project, which can be prorated over the tonnage captured to get a per-metric-ton cost factor:

- If a plant can capture 1 million metric tons per year of $CO_2$ and costs $300 million upfront, the upfront capital cost is $300.00 per MT of capacity per year [$300 million / 1 million MTPA capacity].
- A capital recovery factor (CRF, expressed as an annual percentage rate) is then applied to the $300/MTPA capacity figure to calculate the investment-related cost per metric ton captured. If the CRF is 10% per year, for example, the investment-related cost per metric ton captured is $30/MT captured [$300/MTPA x 10%/year].
- The CRF is derived by solving for an annual dollar amount of net operating cash flow that is sufficient to pay three items: (i) principal and interest on loans amortized over the life of borrowings, (ii) income taxes, and (iii) returns of and on equity investment during the expected life of the equipment. Two CRFs were used in this study, 13% and 16%, for sensitivity purposes.

Currently, most carbon capture projects generally use similar equipment components. The main operating portions, and generally the most expensive portions, of these carbon capture systems for high-concentration $CO_2$ sources are:

- equipment that separates the $CO_2$ from other gases in a mixed inlet gas stream (amine solvent-based acid gas removal, or AGR, systems), and
- equipment that removes any water and compresses the $CO_2$ to pipeline pressure for transportation. If $CO_2$ is already at 100% concentration (on a dry basis) then only the second step is needed.

As a special case, different systems that use cold methanol or propylene glycol as solvents (brand named Rectisol and Selexol, respectively) are used for very high concentrations of $CO_2$, such as would be found downstream of coal gasification equipment (e.g., the Coffeyville, Kansas pet-coke gasification plant) or in a natural gas processing plant whose field gas is highly $CO_2$-contaminated (e.g., field gas from Exxon-Mobil's LaBarge field in Wyoming). It would be unusual to utilize Rectisol or Selexol for concentrations below 25%, especially at ambient pressures.

The Capital Equipment Cost Detail section below describes capital requirements for AGR systems. Published literature contains no generalized examples of alternative technologies that have lower costs than amine-based AGR systems. Indeed, some plant sites cannot support either the space requirements or energy requirements of an amine solvent-based AGR system, in which case other equipment must be used. This was apparently the case for plant-specific reasons at the Air Products & Chemicals, Inc. project at a steam methane reformer at Port Arthur, Texas, causing the company to use a surface chemistry-based Vacuum Swing Adsorber.[3]

## Operating and Maintenance (O&M) Costs

O&M costs include annual fixed operating costs (such as taxes, insurance, overhead, and general plant salaries), semi-fixed operating costs (such as major and minor repairs, maintenance, and overhauls), and non-energy variable operating costs (such as replacement of process chemicals, water, and water treatment). Fixed and semi-fixed costs vary more-or-less directly with original capital cost (i.e., more expensive plants have more expensive parts, more employees, and pay more property tax and insurance). For practical purposes, the truly variable costs are minimal enough to estimate O&M costs by multiplying the original capital cost by a sector-specific percentage rate without losing much accuracy. As described below, those percentages ranged from 4% to 7% depending on the industry.

## Energy Costs

Energy costs per metric ton captured vary widely among published studies mostly due to widely different price assumptions. The actual per-metric-ton-captured unit quantities of electric and fuel energy needed are relatively predictable (i.e., the MWh of electricity needed to compress 1 MT of $CO_2$), as opposed to the highly variable price (the price per MWh). This study relied on the unit quantities of energy inputs, then treated electric and fuel commodity prices as a sensitivity variable.

## Capital Equipment Cost Detail: Compressors

In the scheme of total costs of carbon capture, variations in the costs of compressors translate into relatively small changes in $/MT compressed. For example, the difference between $25/MTPA capacity and $15/MTPA capacity, using a 13% CRF, is $1.30/MT captured, out of a total capture cost that might be between $20 to $80/MT. The application of compressors varies based on the purity of $CO_2$ source and is described below for high purity and lower purity sources.

### Compressors for High Purity $CO_2$ Sources

Pure streams of $CO_2$ from ethanol, natural gas processing, and ammonia/urea nitrogen fertilizer plants generally only require dewatering and compressor systems to capture $CO_2$. Ammonia plants capture $CO_2$ in conjunction with operation of steam methane reformers (SMRs). SMRs, plus downstream gas-water shift reactors, use inputs of heat, water, and natural gas to produce a mixed gas stream primarily consisting of hydrogen gas and $CO_2$, which are separated at that point. The hydrogen (H2) is combined with nitrogen to make ammonia gas (NH3). In most such plants, virtually 100% of $CO_2$ captured from the SMR process is then combined with ammonia to make solid granular urea, a much easier and safer fertilizer to transport and use. Thus, even though $CO_2$ is captured, most of it is used to make urea and very little $CO_2$ is unused and vented. In the aggregate, the amounts of pure $CO_2$ now produced from ethanol, gas processing, and ammonia plants not already being used or being sold by these emitters are quite small in the context of US emissions. This study estimates those available amounts at less than 50 million MTPA, mostly from ethanol fermentation, with a smaller amount of ~40 million MTPA being emitters of large enough size to qualify for Section 45Q tax credits (>100,000 MTPA on a reliable basis).

Ethanol or natural gas facilities are often small projects with expensive compressors, generally with $CO_2$ quantities of 100-600,000 MTPA. Despite a slightly higher cost for compressors, however, ethanol and natural gas processing facilities are the lowest cost overall producers of $CO_2$ since the high purity gas does not require the expensive $CO_2$ scrubbing systems described in the $CO_2$ separation/scrubbing systems section.

### Compressors for Non-High Purity $CO_2$ Sources

For sources where $CO_2$ is not produced in high purity, compressors are also necessary. Published studies report the relationship between compressor size and cost often in terms of horsepower vs. cost, as opposed to volumetric performance (volumes of $CO_2$ compressed) vs. cost. There are two types of compressors: reciprocating and centrifugal. The smaller reciprocating compressors are mechanically similar to pumps, whereas the large centrifugal machines are closer to turbines.

**Reciprocating compressors.** The National Energy Technology Laboratory (NETL) study of industrial capture concluded that plants capturing 100,000- 600,000 MTPA would use reciprocating compressors with bare erected costs (BEC) of ~$43/MT capacity and no real scale economies.[4] BEC is a relatively common term in studies reviewed for this project and generally means the cost of purchased components, materials to install (cement, steel, piping, wiring), and construction labor. The most useful number is the EPCC (Engineer, Procure, Construct Cost) which adds in roughly 10% estimate of engineering and contractor construction supervision. Neither figure includes contractor or owner contingencies, interest during construction, development costs, or working capital. This study typically uses EPCC to refer to costs before contingencies, etc. Above 600,000 MTPA, NETL suggests that centrifugal machines would be used with bare erected costs of ~$20-25/MT capacity dropping into the ~$15/MT capacity area for 1-2 million MTPA volumes (NETL 2014).

Reciprocating compressors are relatively less expensive, can be ordered in standard sizes, and are often assembled in series and/or in multiple connected "trains" to handle large volumes. This means that scale economies are limited since the buyer is buying many small units. Creating multiple trains of the smaller reciprocating compressors allows for redundancy and increases reliability.[5]

**Centrifugal compressors.** Like natural gas combustion turbines, large centrifugal compressors have multiple stages of blades, all turning on a common shaft. This gives rise to scale efficiency possibilities for larger units. Expert consultations indicated that large centrifugal $CO_2$ compressors that boost $CO_2$ from near ambient pressure (15 psi) to pipeline pressures (2200 psi) are not a commodity industrial product, unlike the large compressors used in great quantities along gas pipelines that boost falling pressures from ~1,500 psi back to 2,200 psi. Thus, off-the-shelf reciprocating compressors, rather than centrifugal compressors, are more likely an attractive candidate for compression equipment.

### $CO_2$ Separation/Scrubbing Systems

A key cost driver in carbon capture equipment is carbon-dioxide molecules as a percent of total gas molecules in a volume of gas treated, which is called the molar concentration. In this methodology, concentration refers to molar concentration. Outside the 100% $CO_2$ concentrations seen in ethanol and gas processing, $CO_2$ in industrial and power plant vent stacks is often produced at molar concentrations of 25% or less, generally at atmospheric pressure. Since $CO_2$ is quite heavy compared to the other gas molecules in ambient air, $CO_2$ concentrations measured by weight are typically much higher than molar concentrations.

Preventing less-concentrated $CO_2$ from being emitted and upgrading it to pipeline transport quality requires installation of special equipment to separate the $CO_2$ from other gases in a mixed gas waste stream. The most common, oldest, and best-tested system involves a family of amine solvent chemicals that have a strong affinity for $CO_2$ at low temperatures but that will release the $CO_2$ if boiled.

Other systems, with brand names Rectisol and Selexol, are commonly used in connection with very high concentrations of $CO_2$ ( i.e., in the 60%+ concentration range), yet are specialized technologies that are rarely applicable to the industrial plants examined in this study. Rectisol uses methanol as the cold solvent and Selexol uses propylene glycol. Rectisol and Selexol are primarily used in connection with coal or petroleum coke gasification plants, though they are also used in gas processing of field gas that has extraordinarily higher $CO_2$ contamination. Both entirely dissolve stack gases into a cold solution under pressure, with the pressure then gradually released in a column. Different gases bubble out of the solution at various heights in the column. The $CO_2$ scrubbing process involves spraying an aqueous solution containing the solvent into the top of an exhaust stack (absorber tower) to make contact with the pre-cooled waste gas stream rising up the stack in counter-flow. The $CO_2$-laden solution is then routed to a steam-heated pressure vessel (stripper tower or solvent regenerator) where the $CO_2$ is released, after which the solvent solution is recirculated back to the absorber tower.

Amine solvent systems (e.g., amine acid gas scrubbing systems) are often used in industries such as natural gas processing and fertilizer manufacture. The most common amine compound used is MEA (monoethanoloamine). Others include 2-amino-2-methyl-1-propanol (AMP) or methyl diethanolamine (MDEA). They are now being applied for emissions control purposes in industries where they have not been used historically. For instance, amine solvent systems are used in both examples of North American coal plant retrofits for carbon capture, the Petra Nova/W.A. Parish power plant in Texas, and the Boundary Dam coal power plant in Saskatchewan. The installed costs of the amine systems themselves are typically in the range of $80-$100 per metric ton annual capacity. Cost per metric ton of annual capacity falls with larger size and also falls with higher molar concentrations/pressures of $CO_2$ in treated waste gases.

Empirical evidence gathered from a cross-section of studies validates the concept that higher $CO_2$ concentrations in the treated gas stream drive unit capital costs downward. There is also a theoretical rationale for capital and operating costs to decrease with concentration.[6]

### Analyzing the Equipment Cost for the Amine Solvent-Based Acid Gas Removal ("AGR") Systems

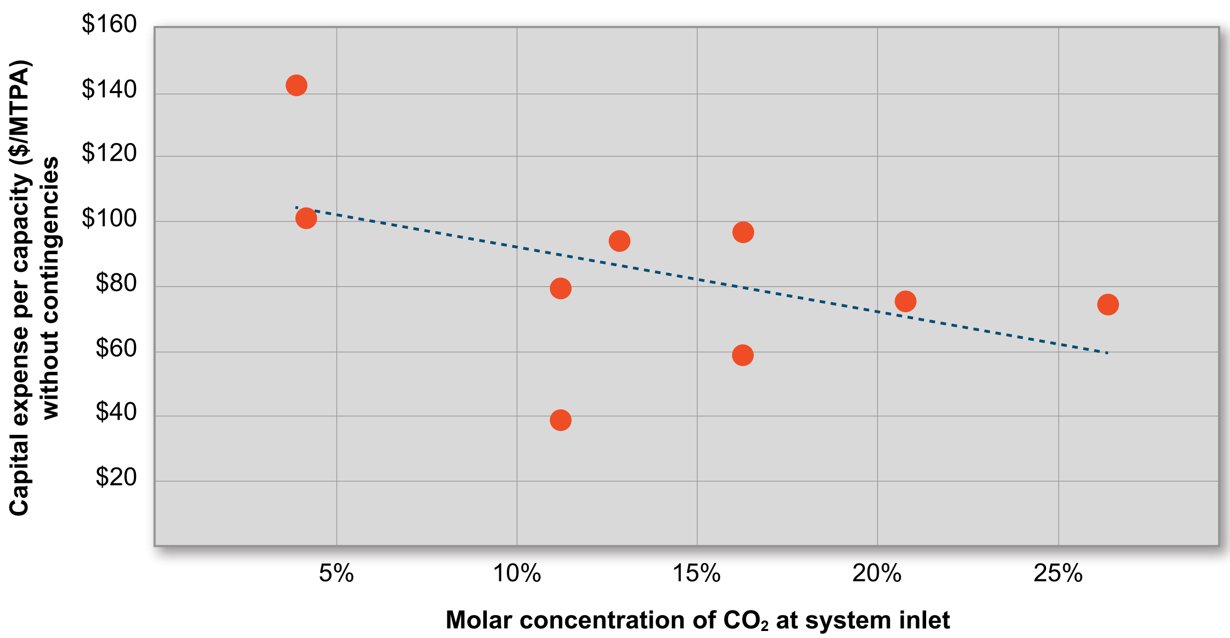
Figure 2 depicts the equipment cost for solely the amine solvent-based acid gas removal (AGR) system portion of various carbon capture projects at industrial and power plant sites. This chart attempted, where possible, to isolate the costs estimated by engineers for the AGR comprised of purchased equipment, materials to erect the AGR system, construction labor, engineering, and construction supervision, while eliminating any project contingencies, owners' costs, and interest during construction, etc. Where information allowed, items such as water infrastructure, ductwork to connect to the original emitting vent stack, etc. were removed.

The y-axis shows the dollar upfront capital expenditure divided by the MTPA of $CO_2$ that flows into the AGR system. The x-axis reflects the molar, or molecular, concentration of $CO_2$ in that inlet gas on a dry basis. For readers who are not gas chemists, the key concentration measure is not the weight of $CO_2$ in a mixed gas stream, but rather the number of molecules of $CO_2$ compared to the number of other types of gas molecules. That is because a molecule of one kind of gas takes up the same amount of volume as a molecule of any other type of gas (at the same temperature and pressure).

Since amine AGR systems depend on amine solvent droplets physically coming into contact with a $CO_2$ molecule, the higher the molar concentration of $CO_2$ in the flowing mixed gas stream, the more probable it is that solvent will come into contact with a $CO_2$ molecule in the absorber tower. Thus, if the $CO_2$ concentration is high, the $CO_2$ can be removed quite quickly in a smaller absorber tower, saving money. A trend line of these costs (dashed line) shows that unit costs ($/metric ton throughput capacity) go down as concentrations rise from the 5% range to the 25% range. A stronger correlation may be expected if the data for the chart had reflected work by a single engineering firm using identical equipment assumptions. However, the data here reflects nine projects in six industries, three currencies, and five different years.

Additionally, many studies do not specify what ancillary equipment or costs may be included with the AGR system line items. Note: This chart does not show the capital cost for the entire carbon capture project—just the capital cost for the single most critical and expensive component, the AGR system.

Figure 2. Equipment cost for the amine solvent-based acid gas removal ("AGR") systems, by $CO_2$ concentration




Cost and system configuration data revealed in metastudy conducted by study authors.

## Other Capital Costs

Other large capital expenditure components typically include:

- Ducts to move exhaust gases to the inlet of the capture system from the vent stacks where they were formerly emitted;
- Cooling systems if the inlet gas is too hot;
- Pre-treatment systems if the inlet gas contains undesirable contaminants (for example, unless virtually all sulfur dioxide has been removed from inlet gas, additional treatment of inlet gas is required);
- Water systems to circulate, clean, and provide make-up water for the solvent system; and
- Storage bins and tanks for materials, including reserves of solvent.

## Sector-Specific Capital Equipment and Financing Costs Used in this Study

As noted above, the annual dollar amount that must be recovered from revenues or incentives equals the upfront cost of the capital equipment times the percentage rate that represents financing and tax costs (i.e., Capex x Capital Recovery Factor = Annual Cost of Equipment). The industry-by-industry central capture project capital equipment cost estimates used for modeling regional supply curves are detailed in Table 2, with further information regarding the capital recovery factor (CRF) in Table 3.

For pure $CO_2$ streams, the major equipment required is a compressor and capital costs per metric ton are accordingly quite low.

- For facilities with low-purity $CO_2$ streams, total capacity costs could reach the \$200/MTPA capacity range. As a simple example, assume bare erected costs plus engineering/construction supervision of \$25/MTPA for compressors, \$100/MTPA for an amine system, and another \$25/MTPA for associated water, electrical, and waste systems, for a total of \$150/MTPA. Multiplying that \$150/MTPA figure times 1.20x for contingencies and times 1.10x again to allow for the cost of funds during construction brings the capacity cost mark to \$200/MTPA.
- The most significant cost items in addition to those mentioned above are (i) cost of ducting, to the extent stack gases need to be routed a significant distance from the old vent stack to the new carbon capture system, and (ii) cost of providing for electricity and steam to run the carbon capture system itself.
- Note that the figures in Table 2 represent the lower cost analytical range, using a 20% contingency factor and CRF of 13%. The CRF is not an exogenous variable, but rather the CRF is the solution to a multi-year, multi-factor model that will meet multiple constraints, with the most important being to provide a specified life-of-project equity return (IRR) to equity. The 13% CRF calculation used the following assumptions: 12-year analysis horizon and debt term, 50% debt leverage, 5% debt interest rate, 2.3x total debt service coverage ratio, 21% federal tax rate and 5-year modified accelerated cost recovery system (MACRS) depreciation using half year convention (without bonus depreciation), and solved for a levered after-tax equity internal rate of return of 10%. The 16% CRF calculation raised leverage to 60%, increased debt interest rate to 6%, lowered traditional debt service coverage ratio (TDSCR) to 2.2x, and solved for a 20% IRR.

## Table 2: Reference capacity, investment cost per unit capacity, and finance cost per metric ton captured

| Category | Sector | $CO_2$ Typical Molar Concentration | Reference Plant Size MTPA | Low-end Capital Investment $/MTPA of Annual Capacity | $/MT Captured Finance Cost at @ 13% x Capex* |
|---|---|---|---|---|---|
| Pure Streams [No AGR Needed] | Natural Gas Processing | ~100% | 600,000 | $39 | $5 |
| | Ethanol | ~100% | 500,000 | $49 | $6 |
| | Ammonia | ~100% | 400,000 | $68 | $9 |
| Hydrogen Plants | Industrial Hydrogen Plants (Refinery and Stand-Alone) | 16% (pre- PSA) | 350,000 | $168 | $22 |
| Large Concentrated Sources | Cement Plants | 21% | 1,000,000 | $187 | $24 |
| | Refinery Fluidized Catalytic Cracking (FCC) | 16% | 1,000,000 | $225 | $29 |
| | Steel Blast Furnace Gas (BFG) Combustion | 26% | 3,000,000 | $281 | $36 |
| | Coal Power Plant | 13% | 1,600,000 | $299 | $39 |
| Large Dilute Sources | Natural Gas Power Plants | 4% | 500,000 | $382 | $50 |

*See derivation of 13% figure in Table 3.
Table 3 shows the inputs from which this analysis derived 13% and 16% CRFs for a 12-year investment horizon.

## Table 3: Summary of inputs to Capital Recovery Factors (CRFs)

| Inputs Used in Deriving Capital Recovery Factors | | |
|---|---|---|
| CRF | 13% | 16% |
| Asset Life | 12 years | 12 years |
| Debt Term | 12 years | 12 years |
| Debt Rate | 5% | 6% |
| Debt as % of Total Capitalization | 50% | 60% |
| After-Tax Internal Rate of Return on Equity Investment | 10% | 20% |
| Corporate Tax Rate | 21% | 21% |
| $CO_2$ Equipment Depreciation | 5-year MACRS | 5-year MACRS |

Note that because the life of Section 45Q tax credits is only 12 years, this analysis also used a 12-year investment horizon (implying the full investment cost is recovered over 12 years). A 20-year horizon may be more appropriate for long-lasting major capital projects, but may raise concerns that the capture units could cease operations once the tax incentives ceased at the beginning of year 13. If the investment horizon is extended to 20 years, the 13% CRF would drop to 9.6% and the 16% CRF would drop to 12.8%.

## Capture Operating & Maintenance Costs

Major operating and energy costs for carbon capture projects include:

- Annual fixed operating costs (such as taxes, insurance, overhead, and general plant salaries);
- Semi-variable operating costs (such as major and minor repairs, maintenance, and overhauls);
- Non-energy variable operating costs (such as replacement of process chemicals, water, water treatment, etc.); and
- Energy variable costs (electricity to drive compressors, motors, pumps, and fans; plus fuel used to make steam to boil $CO_2$-laden solvent).

Because unit quantities of electric and fuel energy loads are relatively predictable (i.e., the amount of electricity needed to run a compressor), as opposed to the highly variable price (the price per MWh to make or buy that electricity), energy variable costs were kept separate from other variable costs.

### Methodology for Determining Capture O&M Costs

For projects in each particular industry sector, a percentage rate was applied to the project's original capital cost as a satisfactory estimate of non-energy fixed, semi-variable, and variable O&M costs. The goal was to derive a representative figure or methodology that could be easily applied across many dozens of capture projects of each type. Furthermore, an operating cost methodology that would scale up and down in a reasonably accurate manner was necessary for carbon capture projects that were bigger or smaller than prototypes for which engineering detail was available.

It is reasonable for operating costs to be strongly correlated with the original plant cost. Detailed studies of particular plant types were surveyed to obtain expected maintenance costs in absolute dollars, in dollars per MT processed, and as a percentage of carbon capture plant construction cost. Authors of these studies often estimated operating costs based on percentages of plant cost, assuming that a larger plant has more parts that may need maintenance or repair than a relatively small plant and that the larger plant costs more than the small plant.

A study of the Duke Energy Gibson Plant[7] used 3% of battery limits investment (roughly corresponding to 1.8% of total investment) to estimate maintenance materials and maintenance investment. Their property tax and insurance figures were also based on the investment cost. Ultimately, approximately half of non-energy O&M costs were directly calculated as a percent of investment. Therefore, O&M should rise with absolute capital cost. Furthermore, if two plants are of the same size, but one was much more expensive to build, it may be likely that its labor rates are more expensive and its spare parts will be more expensive. Finally, there are some scale economies both in building a large plant, and in operating a large plant, and those economics appear to move roughly in tandem:

- Two large fixed cost items are a fixed percentage of plant cost. For local/state property taxes and property/casualty insurance, this analysis used standard percentage figures of 1% and 0.5% respectively. When annual supervisory and labor positions were detailed, they appeared to be correlated with plant cost, and also comparatively small.
- Typical semi-variable costs include maintenance, the need for which is partly triggered by the passage of time and by usage. However, since in virtually

all cases this analysis modeled carbon capture operations that would run at 85-90% capacity factors, these items could be treated as fixed costs. Maintenance materials typically made up 60% or more of maintenance costs, and the cost of maintenance materials varies directly with original plant cost (i.e., replacement costs for expensive machines cost more than replacement parts for cheap machines).

- The main non-energy variable cost in the plants examined by this study was the replacement of amine solvents, especially when those were proprietary formulations. Often prices for solvents are carefully guarded. Nonetheless, big plants that capture large amounts of $CO_2$ use up more solvent that small plants—so again there is a logical reason for the annual solvent replacement bill to be strongly correlated with plant cost.

The particular O&M factors used in this study are listed in Table 4, both as percent and in dollars per metric ton. The only major outlier data point observed in the cross-study comparison of O&M costs was the US DOE NETL study for industrial carbon capture for amine units that used 11.77% of capture plant cost for the annual cost of maintenance materials (NETL 2014). However, US DOE NETL studies for power plant amine capture systems used an O&M share of less than 1% of capture cost, and those power plant systems had been cited as the source for the 11.77% figure. Thus, this analysis disregarded that particular data point, especially as it did not correspond to any other studies, most of which put the maintenance material cost in the 1-3% of capex range.

## Table 4: Operating and maintenance costs

| Category | Sector | $CO_2$ Typical Molar Concentration | Reference Plant Size MTPA | Non-energy O&M as % of Capex | $/MT |
|---|---|---|---|---|---|
| Pure Streams [No AGR Needed] | Natural Gas Processing | ~100% | 600,000 | 6% | $2.35 |
| | Ethanol | ~100% | 500,000 | 7% | 3.42 |
| | Ammonia | ~100% | 400,000 | 5% | 3.40 |
| Hydrogen Plants | Industrial Hydrogen Plants (Refinery and Stand-Alone) | 16% (pre-PSA) | 350,000 | 5% | 8.39 |
| Large Concentrated Sources | Cement Plants | 21% | 1,000,000 | 7% | 13.11 |
| | Refinery Fluidized Catalytic Cracking (FCC) | 16% | 1,000,000 | 4% | 9.88 |
| | Steel Blast Furnace Gas (BFG) Combustion | 26% | 3,000,000 | 5% | 14.03 |
| | Coal Power Plant | 13% | 1,600,000 | 4% | 12.43 |
| Large Dilute Sources | Natural Gas Power Plants | 4% | 500,000 | 5% | 19.08 |

## Energy Costs

### Cost of Providing for Electricity and Steam

In general, the combination of a compressor and an amine system creates a need for ~0.15 MWh of electricity and ~2.5-3.5 MMBtu of fuel per MT $CO_2$, that fuel being combusted to create steam for solvent regeneration. These are rough figures and vary by small but not economically significant amounts, for the purposes of this analysis, depending on compressor efficiencies and the particular heat requirements of each solvent or solvent mixture. The question is how to provide for the electricity and steam. Furthermore, not all steam is appropriate for heating the $CO_2$-rich amine solvent solution in the stripper vessel. The amine system needs relatively low pressure/low temperature steam, whereas most steam generation systems, including power plant boilers, are designed to create very high pressure/high temperature steam.

### Approaches to analyzing the cost of providing electricity and steam

Analysts have taken a variety of approaches to analyzing the cost of providing electricity and steam for capture projects. However, their studies rarely assume the lease risky, least complex, and cheapest methods for providing electricity and steam. This variability has led to a lack of comparability among studies, and it has generally tended to inflate the cost of capture. Three primary approaches to providing electricity and steam, each with distinct cost implications, are described below.

**Build a small power plant to support the capture equipment's needs.** One very expensive method is to build one's own small power plant to make electricity and steam:

- Highly efficient generators: Taking this approach, a project can use very efficient power generation equipment (such as a natural gas combustion turbine combined with a heat recovery steam generator). However, the power generation is generally in the wrong proportion to steam needs, so the project needs to sell more fossil electricity to the grid. In one NETL example, this approach led to more than doubling the electrical output of the old host coal plant.[8]
- Combined heat and power: One can use a traditional industrial combined heat and power (CHP) approach that uses boilers rather than turbines, getting a correct power/steam ratio but at a much higher capital cost. This approach was taken in two International Energy Agency studies, one on cement and another on steel. In the cement study so doing doubled capital costs to build a 45MW coal power plant at an astounding price of $4,000 per kW. The 45MW power plant represented 50% of the Euro 294 million capital cost, or Euro 147 million, which is $184 million after currency and inflation adjustment. $184 million/45,000 kW= $4,089/kW. The typical cost for an efficient new natural gas combined cycle power plant is in the range of $800 per kW, or about 20% of the cost.

**Cannibalize existing power plant.** Another approach, primarily used in the power sector, is to draw from the host power plant (de-rating the power production) to get electricity and steam. Taking electricity from the host power plant is straightforward and reduces the amount of electricity for sale to the grid. If the host coal plant is relatively old or inefficient and is likely to be shut down without the addition of carbon capture, then some amount of de-rating doesn't have a high real-world cost. Depending upon the point of application within the plant, however, drawing steam may require modifications to the host power plant's steam turbine—as was done at considerable expense at SaskPower's Boundary Dam project.

Table 5: Capital expenditure impacts of different approaches to generating electricity and steam to supply carbon capture project energy needs

| Approach to generating additional electricity and steam | Example | Incremental capital expenditure per MTPA capacity | Impact per MT captured at 13% CRF + 5% O&M factor |
|---|---|---|---|
| Build an efficient gas power plant | NETL study on coal power plant retrofit[9] | \$63-\$150/MT | \$11-27/MT captured |
| Small coal boiler CHP | Mott MacDonald IEA cement | \$158/MT | \$28/MT captured |
| Taking steam and power from a host power plant | Implied from NETL new-build Case B11A vs. B11B | \$50/MT including extra generation cost and incremental boiler | \$9/MT captured |
| Gas package boiler for steam | Various developer studies (private) | \$7/MTPA | \$1/MT captured |

**Low capex.** The approach used by developers of carbon capture projects who are seeking to minimize risk and capital cost, with an accompanying modest probability of higher electric and fuel bills is to simply (i) buy electricity from the grid, and (ii) buy an off-the-shelf gas package boiler to make steam. A package boiler is factory made and deliverable on-site.

Throughout the review of various studies there was little difference from industry to industry in the units of electricity and fuel required to run compressors alone, or to run both compressors plus an amine $CO_2$ scrubbing system. Minor variations in exact consumption are relatively small impact items in terms of the overall cost of capture. Prices, however, can have a significant impact in some cases. For example, the price of electricity could be quite cheap if it is treated as an auxiliary load of a power plant, as compared to the case where an over-the-fence amine treatment system is forced to acquire electricity at retail rates from the host emitter.

### Cost of Electricity

- Running only compressors (plus dehydrators) generally consumed on the order of 0.10 MWh per MT.
- Running both amine systems and compressors typically consumed on the order of 0.15 MWh per MT.
- This study used a \$50/MWh electricity price, which corresponds to typical tariffs for large manufacturing facilities. For reference, the US Energy Information Administration (EIA) figures for February 2019 were \$51.80 per MWh for "West South Central" (Arkansas, Louisiana, Oklahoma, and Texas) as the average price of electricity to "Industrial" customers.
- At \$50/MWh the 0.10 MWh costs \$5/MT and 0.15 MWh costs \$7.50.

### Cost of Fuel

- Other than for cases where fuel and steam were self-generated in a combined process, fuel needs were in the 2.5 MMBtu per MT $CO_2$ range based on use of solvent with low heat requirements for regeneration (i.e., Mitsubishi Heavy Industries' K-1 Solvent).
- This analysis used natural gas prices of \$3.50/MMBtu, which are in line with wholesale gas prices. According to the EIA, average annual TX industrial prices for the last six years were \$3.70/MMBtu,

and $3.39/MMBtu for 2018. At $3.50/MMBtu, 2.5MMBtu costs $8.75/MT $CO_2$; and 3.5 MMBtu costs $12.25/MT $CO_2$. Note that though the EIA reports prices paid by industrial consumers for natural gas, only a small portion of industrial users are shown as having reported.

- In some places, such as southern Illinois or Wyoming, coal is very cheap compared to natural gas, and capture projects may make an economic decision to use that cheap coal fuel to generate steam for a capture project instead of more expensive natural gas. For example, some Wyoming coal plants pay coal prices below $1.00/MMBtu, and the EIA shows February 2019 coal delivered to Illinois power plants at $1.86/MMBtu.[10] This configuration was not used in this study. In a more detailed study, using plant-specific fuel costs as shown on utility FERC Form 1 filings may be recommended.

Table 6 shows the electric and fuel parasitic loads assumed for each particular industry. Certain industries have either a zero fuel parasitic load or zero electric load:

- Zero steam/fuel load: For industries that do not require the use of an amine scrubbing system—ethanol, natural gas processing, and ammonia (to the extent of availability of excess $CO_2$ from existing $CO_2$ capture)—there is only a parasitic electric load. That load is primarily to compress $CO_2$. Ethanol compression load is higher because of a smaller reference plant size.
- Zero electricity load: Natural gas combined cycle (NGCC) power plants are shown with zero electric load. These US NGCCs do in fact have an electric load, but that load is effectively hidden in the incremental fuel factor. Following the precedent of a number of other studies, this analysis assumed that the net power generation of the NGCC was reduced to the extent of electric consumption and any capture system consumption of steam generated in the Heat Recover Steam Generator. The effective "de-rating" of the power plant was included as a capital cost attributable to the capture system. The increased fuel load per net MWh delivered to the grid was allocated to the capture system as well (an incremental 2.33 MMBtu per MT captured.) [Note that the alternative would have been to assume a standalone gas-fired package boiler for steam and consumption of power from the grid, as was assumed for coal power plants.]

Table 6: Physical quantities of electricity and fuel required by capture equipment

| Industry | Reference MDEA Plant Size MTPA 85% | Electricity in MWh per MT Captured | Gas in MMBTU per MT Captured |
|---|---|---|---|
| $NH_3$ | 600,000 | 0.10 | 0.00 |
| Cement | 500,000 | 0.16 | 2.55 |
| Ethanol | 400,000 | 0.12 | 0.00 |
| $H_2$ | 350,000 | 0.18 | 2.55 |
| $CH_4$ | 1,000,000 | 0.10 | 0.00 |
| BFG | 1,000,000 | 0.16 | 2.55 |
| PC | 3,000,000 | 0.16 | 2.55 |
| NGCC | 1,600,000 | 0.00 | 2.33 |
| FCC | 500,000 | 0.14 | 2.55 |

## Total capture cost estimates compared to other industry figures

Table 7 compares high and low capture cost estimates derived by analyzing industrial and power facilities. The approach taken by this analysis was to carefully examine the engineering details, equipment lists, operating cost details, and mechanisms to provide for capture unit needs for electricity and steam. Common assumptions were sought on contingencies, financing costs, tax and insurance, natural gas costs, and electricity to create comparability.

Note that Table 7 shows "capture cost" and not "avoided cost," as it subtracts any $CO_2$ emissions imputed to the operation of capture cost equipment. Thus, if a unit captures 1 metric ton of $CO_2$ at a cost of \$50, its capture cost is \$50/MT. If the operation of the capture unit itself emits 0.2 metric tons of $CO_2$ the avoided cost would be \$50 / (1.0 - 0.2) = \$62.5.

The "Other Studies" column in Table 7 reflects adjusted capital recovery factors to the same 13% CRF assumed as the low-end CRF in this analysis. In some cases, there was not enough information to do so. These cases are still cited, erring on the side of being more inclusive in this table despite some non-comparability.

As described above, this analysis assumed that all equipment costs had to be recovered over a 12-year life corresponding to the 12-year 45Q tax credit period. If 20 years had been assumed for capital recovery, the capital recovery rate for the low-end estimate would have been 3.4% lower. The reduction simply results from the project having a longer span of years over which to recover the capital investment. The 3.4% CRF reduction, multiplied times upfront capital costs, would have lowered total capture cost by approximately \$6/MT captured for hydrogen plants, \$6-\$10/MT for the concentrated industrial sources and coal power plants, and \$13/MT for NGCCs. This point is important in policy discussions when considering an extension of the period during which Section 45Q credits can be recovered from 12 years to 20 years. If the credit period were extended, it would be logical to extend the capital recovery period from 12 to 20 years. The exception would be when the host emitter whose stack gases are treated is expected to shut down in a period shorter than the available 45Q credit period.

## Table 7: Total capture costs per metric ton vs. other studies

| Category | Sector | Reference Plant Size MTPA | Capture Details | This Study (low-high) | Other Studies |
|---|---|---|---|---|---|
| Pure Streams [No AGR Needed] | Natural Gas Processing | 600,000 | 100% | $12-15 | ~$15 NETL [11] |
| | Ethanol | 500,000 | 100% | $16-19 | ~$17 NETL[12] |
| | Ammonia | 400,000 | N.A. Unused SMR $CO_2$ | $17-22 | ~$21 NETL[13] |
| Hydrogen Plants | Industrial Hydrogen Plants (Refinery and Stand-Alone) | 350,000 | ~56% of total, 67% of pre-PSA carbon | $48-60 | $36 IEA[14] |
| Large Concentrated Sources | Cement Plants | 1,000,000 | 90% at vent | $55-$69 | $58 Kuramochi [15]<br>$51 IEA[16]<br>$64 NETL[17] |
| | Refinery Fluidized Catalytic Cracking (FCC) | 1,000,000 | 90% at vent | $55-71 | $73 Kuramochi |
| | Steel Blast Furnace Gas (BFG) Combustion | 3,000,000 | 90% at vent | $68-88 | $32 Kuramochi |
| | Coal Power Plant | 1,600,000 | 90% of stack gases bypassed to CCS[18] | $68-89 | $50 (avg.) Rubin/ Herzog[19]<br>$54 CURC[20]<br>$63-$68 LANL/Duke[21]<br>$42-$65 Linde/ICKan[22]<br>$85 Bechtel[23] |
| Large Dilute Sources | Natural Gas Power Plants | 500,000 | 90% of stack gases bypassed to CCS | $76-104 | $69 CURC[24]<br>$74 (avg.) Rubin/ Herzog[25] |

This methodological appendix has detailed our process of identifying potential candidates for capture retrofit projects at existing US power and industrial sources. This methodology has also described the factors that went into estimating cost of capture for each candidate facility. The methodology of this study was unique, in part, because only facilities that exhibited certain characteristics favorable to capture retrofit were selected for further study, and because 100% capture was not assumed at each of these facilities, allowing for more economically efficient sizing of capture units. For this reason among others, cost estimates in this study are generally lower than have been found in other studies. Furthermore, this methodology underscores that cost per metric ton of $CO_2$ captured would be lowered if the life of the Section 45Q tax credit were extended, allowing capital recovery rates to be lowered and spread over a longer period of time.

# METHODOLOGICAL APPENDIX REFERENCES


1 US EPA, Facility Level Information on Greenhouse Gases Tool, August, 2018. https://ghgdata.epa.gov/ghgp/main.do

2 ABB, ABB Ability Velocity Suite, 2019. https://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite

3 Personal conversation of author's with company personnel.

4 Steve Herron (WorleyParsons Group), Alexander Zoelle (Booz Allen Hamilton), Wm Morgan Summers (NETL). Cost of Capturing $CO_2$ from Industrial Sources. National Energy Technology Laboratory. DOE/NETL-2013/1602. Jan 10, 2014. https://netl.doe.gov/projects/energy-analysis-details.aspx?id=1836

5 Interview with Scott MacDonald of ADM. ADM uses banks of reciprocating compressors in its ~1 million MTPA Decatur Illinois project.

6 Praveen Bains, Peter Psarras, and Jennifer Wilcox, "$CO_2$ capture from the industry sector" in "$CO_2$ Summit III: Pathways to Carbon Capture, Utilization, and Storage Deployment", Jen Wilcox (Colorado School of Mines, USA) Holly Krutka (Tri-State Generation and Transmission Association, USA) Simona Liguori (Colorado School of Mines, USA) Niall Mac Dowell (Imperial College, United Kingdom) Eds, ECI Symposium Series, (2017). https://dc.engconfintl.org/co2_summit3/8

7 Jones, D A, McVey, T, and Friedmann, S J. Technoeconomic Evaluation of MEA versus Mixed Amines for $CO_2$ Removal at Near-Commercial Scale at Duke Energy Gibson 3 Plant. United States: N. p., 2013. Web. doi:10.2172/1096594.

8 NETL's Case 2 in "Eliminating the De-rate of Carbon Capture Retrofits", DOE/NETL-2016-1796.

9 Eliminating the De-rate of Carbon Capture Retrofits, DOE/NETL-2016-1796.

10 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_4_10_a

11 NETL/Booz Allen 2014 table 7-25 shows $17.38/MT, and this analysis made $2/MT adjustment for mistake in maintenance material cost. Plant was sized at 551,818 MTPA.

12 NETL/Booz Allen 2014 graph Exhibit 7-9 (p. 43/144) shows ~$21 per MT for ~500,000 MTPA, however needed to subtract ~$4/MT for mistake in maintenance material cost.

13 NETL/Booz Allen 2014 table 7-16, shows $26.26/MT, and this analysis made $5/MT adjustment for mistake in maintenance material cost. Plant was sized at 389,639 MTPA.

14 IEA Levelized Cost of Hydrogen report with key assumptions converted to USA values: Euro USD @1.22 2014 Q4, 13% CRF, $50/MWh power, & $3.50/MMBtu gas. Also corrected for improper consultant calculation of cost of funds during construction. This study and IEA both assumed amine capture at ~300psi and ~16% molar concentration. Other studies have higher costs but use a less cost-effective configuration, so comparability is difficult. Post-PSA tail gas is disadvantaged by low pressure which requires an intermediate compressor in IEA analysis. Vent stack capture treats a far more dilute $CO_2$ stream which raises costs.

15 Kuramochi (2012) in tables 7, 8, 9, and 11, gave energy quantities in GJ, capital cost in 2012 Euro/metric ton, and O&M as % capital cost. From those this analysis calculated capture cost using 1.05 GJ/MMBTU, 0.28 MWh/GJ, $3.50/MMBtu gas, $50/MWh power, 1.28 USD/EUR in 2012, and 3% change in the CEPCI Index from 2012 to 2018. Few details in Kuramochi's study.Adjusted to remove capital expenditure on SOx NOx equipment that should not have been charged against CCS, and to remove a coal-fired Combined Heat and Power plant, using boilers and grid power instead.

16 Adjusted to remove capital expenditure on SOx NOx equipment that should not have been charged against CCS, and to remove a coal-fired Combined Heat and Power plant, using boilers and grid power instead.

17 Adjusted to remove SOx NOx equipment, and for mistake in maintenance material cost.

18 Similar to successful NRG W. A. Parish Unit#8 retrofit, this analysis sized capture unit at a level that could capture 90% of stack gases when generator(s) are running at approximately minimum turndown levels or on approximately 50% of stack gases on 2x1 combined cycle natural gas turbine plants. In general—but highly dependent upon unit operating patterns, this approach will allow 50-60% overall capture rate, with the capture rate going up as unit capacity factor declines.

19 Estimates are based on retrofits of subcritical coal plants, and subcritical plants might be modestly more expensive than supercritical coal plants if the both subcritical and supercritical plants studied used self-generated electricity and steam to meet electric and thermal parasitic loads. Herzog/Rubin (2015) cite six supercritical coal studies, with capture costs in $/metric ton (low to high) at $36, $45, $46, $46, $47, and $53, with a mean of $46. This analysis inflated the $46 by 8% reflecting change in the CEPCI Index from 2015 to 2018.

20 CURC (2018) figures for capex, O&M, and heat rate changes. Capture cost calculation above used 13% CRF, $2/MMBtu coal, 85% plant capacity factor, and 90% capture. Tables B-6 & B-7 using Year 2020 values.

21 Technoeconomic Evaluation of MEA versus Mixed Amines for $CO_2$ Removal at Near-Commercial Scale at Duke Energy Gibson 3 Plant", Jones, McVey, and Friedman (2013), LLNL-TR-642494, Table 3.2, p. 21/69. The figures in the report are $60 $64, which this analysis inflated by 6% reflecting change in CEPCI Index from 2013 to 2018.

22 Integrated CCS for Kansas (ICKan) study “Final Report Appendices” (2018). Study principal investigators were Eugene Holubnyak and Marin Dubois. Award Number: DE-FE0029474. Cited material reflects Jeffrey Energy Center, with calculations having been performed by Linde based on Linde/BASF amine system. See table 5.4 and text below table at p. 77/237. Numbers at low end of range reflect more efficient approaches to capture of waste heat for use in solvent regeneration. Analysis for smaller Holcomb power plant showed $46-$71/MT (Table 5.8 p. 83/277).

23 “Retrofitting an Australian Brown Coal Power Station with Post Combustion Capture, a Conceptual Study”, Bechtel Infrastructure, 2018. Cited AUD 935MM for capex and AUD 60MM/yr for non-fuel operating expenses on 2.4 MM MTPA capture module (Table 1.2-1 page 9/131). Converted to USD at 0.77 exchange rate used in study, used 13% CRF, and used same fuel and electricity quantities and prices as calculations. The study itself did not give capture or avoided costs.

24 CURC (2018) figures for capex, O&M, and heat rate changes. Capture cost calculation above used 13% CRF, $3.5/MMBtu natural gas, 85% plant capacity factor, and 90% capture. Tables B-8 & B-9 using Year 2020 values.

25 Rubin/Herzog cite six NGCC studies, with capture costs in $/metric ton (low to high) at $48, $58, $65, $80, $88, and “$104”, with a mean of $74. The “$104” figure is the mid-range from EPRI which actually had a range of $86-$130 without supporting engineering information. Removing that $104 figure reduces the mean to $68.