
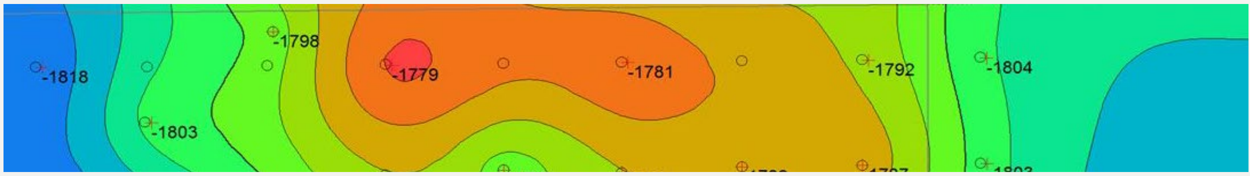

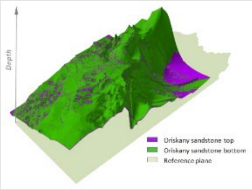


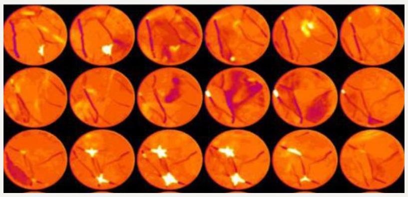


Evaluating CCS Cost Options for CO_2 Sources in the Central United States

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Disclaimer

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ACRONYMS AND ABBREVIATIONS

2008$	2008 dollars
2011$	2011 dollars
2018$	2018 dollars
CCS	Carbon capture and storage
CF	Capacity factor
CO_2	Carbon dioxide
d	Day
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
FE	Fossil Energy
ft	Feet
gal	Gallon
GC	Gulf Coast
GHG	Greenhouse gas
GIS	Geographic information system
ID	Identifier
IEA	International Energy Agency
in.	Inch
LCOE	Levelized cost of electricity
mD	Millidarcy
mi	Mile
mi^2	Square mile
MMscf	Million standard cubic feet
Mt	Million tonnes
Mt.	Mount
MW_e	Megawatt electric
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
O&M	Operation and maintenance
QGESS	Quality Guidelines for Energy System Studies
SCPC	Supercritical pulverized coal
ROW	Right-of-way
tonne(s)	Metric ton(s) (1,000 kilograms)
U.S.	United States
yr	year

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Executive Summary

Carbon capture and storage (CCS) is considered one of many emerging strategies essential in the global effort to meet the dual challenge of providing affordable and reliable energy while addressing rising greenhouse gas emissions, particularly anthropogenic emissions of carbon dioxide (CO_2) into the atmosphere, which are the most significant. [1] The Central United States has an abundance of CO_2-generating sources that would likely require tailored approaches to CO_2 management. This analysis divided the Central United States into three regional impact areas to explore options a CO_2 source faces when transporting and storing its captured CO_2. Each regional impact area had a specifically designed CCS network that connected the source types and geologic storage reservoirs through two transportation options. Overall CCS costs (i.e., summation of capture, storage, and transport costs) were evaluated from a CO_2 source's perspective. Costs for each component of the integrated CCS value chain (in nominal 2018 dollars) were determined through a suite of National Energy Technology Laboratory-developed tools and resources. Four source types with annual CO_2 capture rates ranging from 0.12 to 4.33 million metric tons were assessed in this analysis. Saline storage options represented both dome and regional dip structural geology specific to eight storage reservoirs located in the Denver, East Texas, Gulf Coast Onshore, Illinois, Ozark Plateau, Powder River, Williston, and Wind River basins. A dedicated pipeline network and trunkline network were modeled to connect a CO_2 source to a storage reservoir. For simplicity, only results for the dome structural setting and largest trunkline diameter were considered.

Analysis results indicated that the location of the CO_2 source provided benefits or challenges that affected CCS costs with different portions of the CCS value chain having more of an effect on costs depending on the regional impact area and transportation network. In the Central CCS Network Regional Impact Area, transport costs were the largest component of total CCS costs (51–82 percent) when a dedicated pipeline was used, while capture costs were the smallest. When a trunkline network was utilized, storage costs became the largest cost component (27–68 percent), but capture costs still remained the smallest cost component. No matter the transportation option, capture costs were the highest cost component of the total CCS costs in the Northwest CCS Network Regional Impact Area (Northwest Impact Area) and Gulf CCS Network Regional Impact Area (Gulf Impact Area) (61–84 percent of the total CCS costs when a dedicated pipeline was used and 69–85 percent when a trunkline network was used). Storage costs were the lowest cost component (6–16 percent when a dedicated pipeline was used, and 9–19 percent when a trunkline network was used) of total CCS costs for the majority of sources within the Northwest Impact Area and Gulf Impact Area; there were few instances where transport costs were the lowest component.

Overall, the analysis emphasized the significance of the location of a CO_2 source, capture rate of CO_2 source, quality of storage reservoir, and distance between CO_2 source and storage reservoir on overall CCS costs.

1 INTRODUCTION

Global populations and economies are expected to grow over the next two decades, thus, increasing global energy demand. [2] Even though studies by the United States (U.S.) Energy Information Administration (EIA) and International Energy Agency (IEA) predict energy demand to remain flat or decline within the United States, [2] carbon mitigation strategies will still be required to curb greenhouse gas (GHG) emissions. Carbon capture and storage (CCS) is considered one of many emerging strategies essential in the global effort to meet the dual challenge of providing affordable and reliable energy while addressing rising GHG emissions, particularly anthropogenic emissions of carbon dioxide (CO_2) into the atmosphere, which are the most significant. [1] Most long-term forecasts of future energy and economic outlooks identify widespread deployment of CCS as an essential component of clean energy strategies to meet energy delivery goals and reduce GHG emissions. [2] However, extensive CCS deployment still faces challenges in terms of financing and economic viability. [3] [4] [5] CCS is a supply chain that involves the capture (separation and purification) of CO_2 from stationary sources (e.g., fossil-fueled power plants or industrial processes) so it can be transported to a suitable storage reservoir (also known as a sink) for injection deep underground for safe, secure, and permanent storage. [1] Costs at each stage of the supply chain are dependent on supply chain-specific circumstances that vary with each CCS project. Capture costs vary with CO_2 concentration, while storage costs vary depending on location and nature of the storage formation. Costs vary for CO_2 transport due to several factors: volume, distance, and terrain. [1]

Worldwide, only a few fully integrated CCS projects that capture and store large volumes of CO_2 are underway; however, according to IEA and Global CCS Institute, the number of large-scale CCS projects is slowly growing and diversifying in terms of source types capturing and geologically storing CO_2. [6] [7] The small- and large-scale CCS projects that have been completed or are currently in operation worldwide [8] [9] have demonstrated that significant CO_2 emissions reductions are possible. The United States has established itself as the world leader in CCS deployment with approximately 85 percent of the world's CO_2 pipelines and 80 percent of the world's CO_2 capture capacity. At this position, the United States has substantial capability to drive widespread deployment. However, its annual CCS capacity of 25 million metric tons (tonnes) represents less than 1 percent of the U.S. CO_2 emissions from stationary sources, thus, emphasizing the significance of further deployment. [1] Broader CCS deployment will depend not just on its technical feasibility but also a variety of approaches including the presence of policies and regulations supporting large-scale/long-term financial investments and cost effectiveness, [10] identification and effective characterization of potentially viable storage sites, and continued support for early research and development efforts. [3] These approaches must be applicable across different industries given the unique business cases specific to the variety of CO_2 sources that may consider CCS. One approach that can aid the growth of CCS in the United States and make CCS economically feasible is the incentive of the tax credit available under Section 45Q of the Internal Revenue Code (hereafter referred to as 45Q). This policy provides a per tonne of CO_2 performance-based tax credit that can be claimed by a carbon capture project when the CO_2 is either 1) securely stored in geologic formations, like oil fields or saline reservoirs; or 2) beneficially used as a feedstock to produce products like chemicals, concrete, or fuels. [11] [12] The Bipartisan Budget Act of 2018 amended 45Q to expand the value, duration, and eligibility of the credits. State incentives, like liability transfer,[a] also have the potential to make CCS economically feasible. Even with these incentives, many have suggested that additional financial incentives and policy initiatives are still needed to make CCS financially attractive and prompt wider technology deployment. [13] [14] [15]

Since the writing of this report, the Inflation Reduction Act (IRA) was passed in 2022, which included improvements to 45Q, such as reducing the minimum capture rate requirements, improving the ease of monetizing the tax credits, and increasing the per tonne value of the credits when certain labor requirements are met. [16] Hereafter, all references to 45Q in this report refer to 45Q as amended by the Bipartisan Budget Act of 2018.

Studies that assess extensive CCS deployment, i.e., deployment at scales large enough to meet nationwide decarbonization goals, often do not focus on the infrastructural obstacles faced by first-mover and early adopter CCS projects, namely limited access to the economies of scale associated with shared high-capacity CO_2 transport and storage infrastructure. Examples of extensive CCS deployment studies include the Great Plains Institute's (GPI) 2020, "Transportation Infrastructure for Carbon Capture and Storage Whitepaper on Regional Infrastructure for Midcentury Decarbonization" [17] and Princeton's 2021 "Net-Zero America: Potential Pathways, Infrastructure, and Impacts" [18] reports. The GPI study assessed two scenarios based on time horizon for deployment and economic considerations. The study determined between 281 million metric tonnes (Mt/yr) and 669 Mt/yr of CO_2 could be captured and stored assuming an optimized CO_2 trunkline pipeline network existed in each scenario between 45Q-eligible stationary CO_2 sources in the Central U.S. and an unreported number of low-cost potential saline storage and [primarily] enhanced oil recovery (EOR) project sites that fit the scenarios' qualifications. [17] The Princeton study assessed six different scenarios based on demand-side energy source assumptions regarding electrification, biomass, and renewable energy; four of which utilized CCS. The Princeton study's CCS scenarios optimized CO_2 trunkline pipeline networks within the contiguous U.S. to transport and store from 0.9 to 1.7 billion tonnes (gigatonnes) per year by 2050 captured from over a thousand various proposed CO_2 sources (and CO_2 source aggregation points where smaller pipelines combine to feed a large trunkline) to an unspecified number of underground storage sites that combined comprise "thousands of injection wells". [18] These macro-level studies are insightful to help provide context to the immense scale of infrastructural deployment needed to meet decarbonization goal proposals; however, their projections rely on CCS cost reductions derived from economies of scale provided by optimized networks of shared high-capacity transport (i.e., trunklines) and storage infrastructure. The majority of existing, and many proposed, CCS project deployments (i.e., first movers) are single source-to-sink projects, like the Illinois Basin Decatur Project and its expanded Illinois Industrial CCS Project [19] or the more recently permitted Red Trail Energy Project [20] and Project Tundra [21], where single CO_2 sources and single reservoir matching has been planned. Macro-scale studies, therefore, can be given additional context and complimented by regional analyses that infuse source-specific and location-specific details in

[a] The transfer of liability of a CO_2 storage site from geologic storage operators to the state after a certain period of time.

order to assess CCS technical viability and cost factors from the perspective of individual CO_2 sources that are likely to be first movers capable of helping jumpstart at-scale CCS deployment.

While CCS is considered a capable carbon management strategy, the geographical and geological impact of a region on source-to-sink integration is often overlooked when evaluating the technology. Depending on the region, a CO_2 source can face many challenges and benefits in choosing its best CCS cost option for the capture, storage, and transport of its CO_2. The U.S. Department of Energy's National Energy Technology Laboratory (NETL) has looked at CCS cost options from a CO_2 source's perspective across various regions of the United States with storage limited to onshore, saline-bearing formations through a series of studies focusing on integrated CCS networks:

- The 2014 Grant et al. study [22] looked at single CO_2 source-to-sink matching based on source-specific capture, varying storage reservoir quality options (based on depth, formation, thickness, porosity, structure, and areal extent), and transporting CO_2 via a dedicated pipeline (based on distance from storage sites) that connects a single source to a single storage site. A modular approach was used to evaluate "per tonne of CO_2 costs" (hereafter referred to as $/tonne) for a given CO_2 source, pipeline network, and storage option across the CCS value chain. The methodology enabled evaluation of many source-to-sink combination scenarios and facilitate straightforward CCS component integration to calculate total CCS costs across the evaluated scenarios. Costs were examined for CO_2 source locations and storage reservoir options within the Appalachian and Illinois basins. Capture costs were based on NETL's November 2010 "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity" report. [23] Transport and storage costs were modeled using the 2014 versions of the Fossil Energy (FE)/NETL CO_2 Transport Cost Model (CO_2 Transport Cost Model) and FE/NETL CO_2 Saline Storage Cost Model (CO_2 Storage Cost Model), respectively. This analysis was the first integration of these modeling capabilities of the CO_2 Transport Cost Model and CO_2 Storage Cost Model were combined with the cost of capture to estimate an all-inclusive cost for capture, transport, and storage. The study concluded that good-quality storage reservoirs, even though they might be relatively far away from a given CO_2 source, could still be economically favorable over closer, lower-quality storage reservoirs. However, constructing a dedicated pipeline to a storage reservoir further away would increase the overall CCS cost for a project, which might not be suitable or economically feasible for small CO_2 sources.
- The 2018 Grant et al. study [24] used concepts from the 2014 Grant et al. study [22] to assess low-cost storage and transport options on a $/tonne basis for CO_2 sources located in the northeastern United States. Storage reservoirs within the Appalachian, Gulf Coast Onshore, and Illinois basins were evaluated, which provided various reservoir quality options. Besides a dedicated pipeline, a trunkline was also considered as another transportation option. A trunkline network consists of pipeline segments (i.e., gathering pipelines, trunklines, and distribution pipelines) and hubs connecting multiple sources to multiple storage sites. An overall CCS cost was calculated for each source connected to

each storage reservoir by each pipeline network. Just like the 2014 Grant et al. study, [22] NETL-developed resources and tools were used to model capture, transport, and storage costs. Capture costs were based on NETL's 2014 "Cost of Capturing CO_2 from Industrial Sources" report [25] and NETL's 2015 "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal and Natural Gas to Electricity" report. [26] Transport and storage costs were modeled using either modified or non-public versions of the CO_2 Transport Cost Model and CO_2 Storage Cost Model, respectively. This analysis also highlighted key cost drivers within each component of the CCS value chain. The objectives of this analysis were to see if Gulf Coast reservoirs provided low cost options for the northeast sources, how much a trunkline network would lower costs, and if storage options for industrial sources were like those for electric power plants. Results of this analysis indicated that storage in the highest-quality reservoirs via trunkline transport was not always the lowest CCS cost option. Also, low-cost CCS can be due to the CO_2 source's proximal location to suitable CO_2 storage sufficient for the mass of CO_2 requiring storage. Key outcomes from the study results that support these findings included 1) source type and location can have an impact on the relative importance of proximity to storage reservoirs, 2) economies of scale are present in each link of the CCS value chain, 3) high-quality/high-capacity storage reservoirs may promote distal versus proximal reservoir selection, and 4) trunklines can reduce the per tonne transport cost, especially for a lower-volume source.

This analysis is the third in this series of CCS studies. It uses concepts from the 2014 and 2018 Grant et al. studies [22] [24] to evaluate options a CO_2 source faces when transporting and storing its captured CO_2 within the Central United States. The approaches of assessing each component of the CCS value chain and its cost drivers mentioned in the 2017 Vikara et al. study [5] and 2018 Grant et al. study [24] were applied to this analysis. The Central United States has several clusters of anthropogenic CO_2 sources but depending on the area, very little storage options, thus, posing a challenge for the region; however, there are also incentives like access to high-quality storage reservoirs, gradual application of many states moving toward regulatory primacy for overseeing CO_2 storage operations [27] and availability of state incentives [28] that could provide benefits. To explore these challenges and benefits, the Central United States was split into three regional impact areas: Central CCS Network Regional Impact Area (Central Impact Area), Northwest CCS Network Regional Impact Area (Northwest Impact Area), and Gulf CCS Network Regional Impact Area (Gulf Impact Area). Each regional impact area had a specifically designed CCS network that connected the source types and geologic storage reservoirs via two transportation options. Four regionally specific source types that qualified for the 45Q tax credit with locations based on a cluster method were modeled at seven regionally significant locations in the Central United States. The source types were a cement production plant, ethanol production plant, natural gas processing plant, and supercritical pulverized coal (SCPC) electric power plant with capture rates ranging 0.12–4.33 million tonnes per year (Mt/yr). A total of eight storage reservoirs varying in proximity from the sources and quality of storage reservoir were modeled across the three regional impact areas under dome and regional dip structural settings. These storage options were within the Denver, East Texas, Gulf Coast Onshore, Illinois, Ozark Plateau, Powder River, Williston, and Wind River basins and were connected to a source via a dedicated pipeline network or trunkline network that followed existing natural gas pipeline rights-of-way (ROW). With these attributes, these modeled CCS networks might represent more realistic CCS networks. NETL-developed resources and tools were used to determine capture, storage, and transport costs in nominal 2018 dollars (2018$), so overall CCS costs (i.e., summation of capture, storage, and transport costs) could be evaluated for each regional impact area from the CO_2 source's perspective to find the lowest CCS cost source-to-sink combination. The objectives of this study were to determine potential sources that qualified for the 45Q tax credit and other incentives, what storage reservoirs would be used and to what degree, how the designs of the dedicated pipeline network and trunkline network would impact costs, and the reasonably low cost options for the source within the Central United States study area.

This analysis sets the framework and basis for understanding the cost options, benefits, and challenges CO_2 sources are facing in the Central United States and allows a bridge for studying the impacts of 45Q within the area. A supplementary study based on the 2018 amendment to 45Q, was completed on the Northwest Impact Area to examine the impacts of the 45Q tax credit on the overall CCS costs for the source types and geologic storage reservoirs in the Northwest Impact Area. [29]

2 Analysis Approach Overview and Assumptions

The overall CCS cost considered in this analysis consists of three main components: 1) capture, 2) storage, and 3) transport. This overall CCS cost was determined by taking the sum of the individual capture, storage, and transport costs (Overall CCS Cost Equation 2-1), a concept used in studies completed by Grant et al. [22] [24] that applied a modular approach for evaluating $/tonne for a given CO_2 source, storage option, and transportation network. In order to maintain consistency in the cost calculations, the CO_2 rate for capture, storage, and transport were kept the same for a particular scenario, so other associated parameters were governing the changes in costs.

$$f_{CCS} = f_C + f_S + f_T$$

Overall CCS Cost Equation 2-1

Where

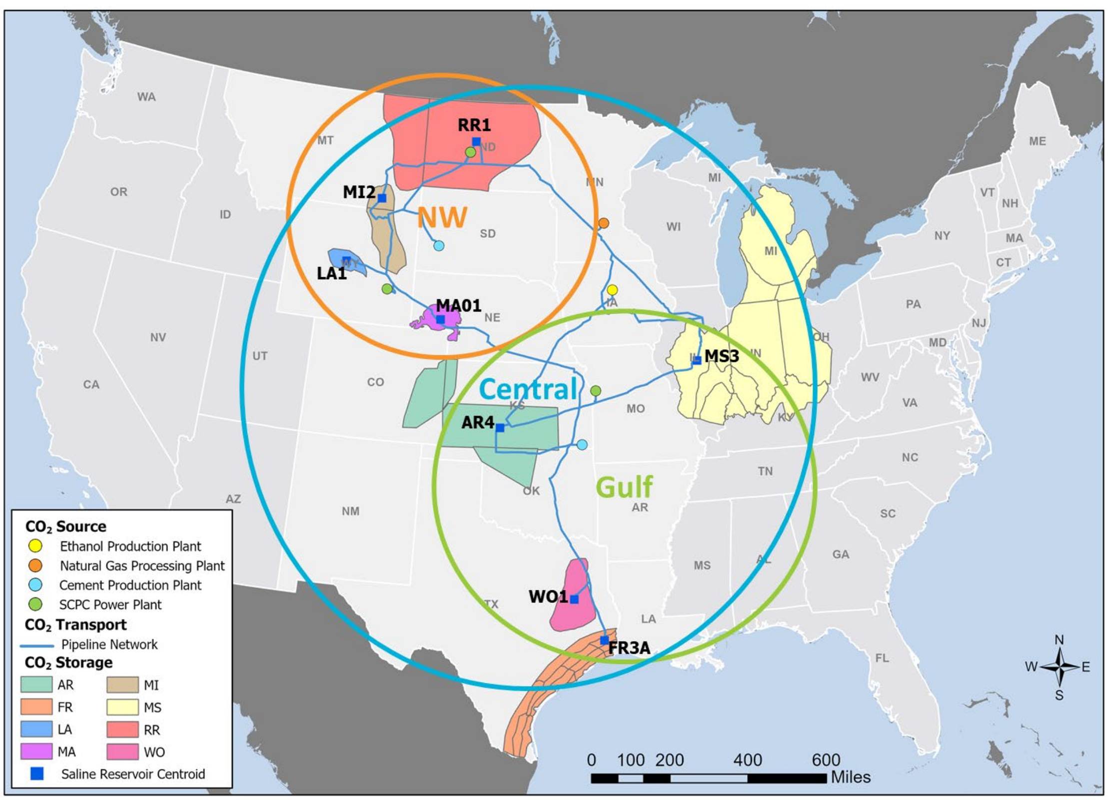
f_C	= capture cost for a given CO_2 source ($/tonne)
f_S	= storage cost for a given storage reservoir ($/tonne)
f_T	= transport cost for a given transportation network ($/tonne)

Publicly available data, software, and NETL-developed open-source models, databases, and publications were used to determine the source locations and transportation network design and estimate costs for each component of the CCS value chain. The capture cost was based on capturing CO_2 from power plants described in NETL's 2019 "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" Revision 4 report (Bituminous Baseline Rev4 Report) [30] and industrial plants in NETL's 2014 "Cost of Capturing CO_2 from Industrial Sources" report (Industrial Report) [31]. Industrial sources are as critical as power plants to assess the CO_2 emissions in the study area. For example, ethanol production plants show a natural cluster in the study area without a nearby storage reservoir. While the emissions of a single ethanol production plant are small, it is critical to understand the potential costs and solutions for all the ethanol production plants in the cluster. The capture costs for the power plants and industrial sources used methodology per the 2019 "Quality Guidelines for Energy System Studies (QGESS): Cost Estimation Methodology for NETL Assessments of Power Plant Performance," (QGESS: Cost Estimation of Power Plant Performance). [32] The storage cost represented the cost to safely and securely inject CO_2 into a saline storage reservoir while abiding by the U.S. Environmental Protection Agency's (EPA) Class VI requirements; this cost was determined using the CO_2 Storage Cost Model. [33] The transport cost was based on CO_2 pipeline transport. Two systems were considered for modeling—dedicated pipeline network and trunkline network—using the CO_2 Transport Cost Model. [34] For the trunkline network, it was assumed that there were small segments of dedicated gathering and distribution pipelines connecting to the main trunkline. In some cases, the pipeline had a small diameter with long transport distance and substantial elevation change. Further details on the methodology and assumptions for modeling each link of the CCS value chain as well as the use of these resources is described in the following subsections.

2.1 Study Region Overview

The study area for this analysis was the Central United States, which, for the purpose of this analysis, is defined as Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. This area was chosen because of its variety of CO_2 source types with some likely "first-movers" for CO_2 management, unique business options and challenges/benefits for a source based on its location, gradual application of many states moving toward regulatory primacy for overseeing CO_2 storage operations, [27] and availability of state incentives. [28] There are many CO_2 sources within the Central United States but not enough suitable underground geology to store the captured CO_2. Deep saline reservoirs possess the most potential for CO_2 storage due to their large capacities; however, they are either sporadic throughout the region or nonexistent (i.e., eastern part of region—Minnesota to northern Arkansas—and majority of Nebraska). There are other suitable CO_2 storage options within the Central United States (e.g., oil and gas reservoirs and unmineable coal beds), but their total CO_2 storage capacities are a lot less than saline reservoirs. [35] As shown in Exhibit 2-1, the Central United States study area was broken into three regional impact areas to assess the challenges/benefits and options a source faces depending on its location – the Northwest (circled in orange), the Gulf (circled in green), and the Central (circled in blue). A more detailed description of the impact areas, sources, transportation networks, and storage reservoirs is discussed in Section 3.

Exhibit 2-1. A map of the three regional impact areas evaluated within the Central United States



2.2 CO_2 CAPTURE

Capture is the first component in the CCS value chain. It involves obtaining CO_2 from power-generation facilities or industrial plants through different capture technologies (e.g., pre-combustion or post-combustion). Types of CO_2 sources that meet the requirements for 45Q tax credits [36] and were plentiful in the Central United States study area were evaluated in this analysis with their annual mass of CO_2 captured (and their capture costs) fixed. Costs for these CO_2 sources along with their locations were estimated using software programs and data from NETL-developed, open-source resources and publications.

2.2.1 CO_2 Capture Costs

The cost of capturing CO_2 is typically affected by the source type (i.e., electric power plant or industrial plant) and its respective flow rate and CO_2 concentration in the flue gas. [37] High purity sources (e.g., ethanol and natural gas processing plants) provide a relatively pure stream of CO_2 to meet pipeline transport standards with greater than 90 percent CO_2 by volume and few other constituents. These sources typically have lower CO_2 capture costs. For low-purity sources (e.g., cement and conventional PC power plants), the purity of the CO_2 stream is reduced. Therefore, their capture cost includes increasing the CO_2 concentration and reducing other constituents to meet pipeline standards. The CO_2 stream's purity reflects the type of combustion or industrial process specific to the CO_2 source type. [38] Several factors, including those mentioned above, drive the selection of capture technologies (e.g., pre-combustion and post-combustion) and materials (e.g., monoethanolamine and methyldiethanolamine). Because of the large capital investment required for the capture equipment and associated energy consumption, the capture portion is usually the largest cost component of an integrated CCS system for a low purity source. [39]

Four CO_2 source types were modeled in this analysis with all meeting requirements for 45Q tax credits (i.e., greater than 100,000 tonnes/yr for industrial plants and greater than 500,000 tonnes/yr for electric power plants). [36] One of the four CO_2 source types was a newly built SCPC electric power plant with a capacity factor (CF) of 85 percent and capture rate of 90 percent. The plant's specifications were based on work reported in the Bituminous Baseline Rev4 Report. [30] All cases within the Bituminous Baseline Rev4 Report used common methodologies and sets of technical and economic assumptions for different power plant configurations (e.g., SCPC non-capture vs. SCPC capture) and were evaluated based on a greenfield site. Costs were reported in real 2018$. To warrant methodologically-sound, consistent, and transparent technology assessments and comparisons, the Bituminous Baseline Rev4 Report relied on information within NETL's QGESS reports, which provide guidance on several topics including cost estimation. [30] The cost metric used in the Bituminous Baseline Rev4 Report was the levelized cost of electricity (LCOE),[b] revenue required by the generator per net megawatt-hour (MWh) produced to meet desired return on equity. [30] The LCOE was used to calculate the CO_2 break-even sales price (on a $/tonne basis), which is the minimum CO_2 plant gate sales price that will encourage carbon capture relative to a defined reference non-

[b] Detailed information on the LCOE calculation and financial parameters can be found in QGESS: Cost Estimation of Power Plant Performance. [47]

capture plant. The break-even sales price equation is given in SCPC Break-Even Sales Price Equation 2-2. [30]

$$CO_2\ Break - Even\ Sales\ Price = \left(\frac{LCOE_{CCS} - LCOE_{Non-CCS}}{CO_2\ Captured}\right)$$

SCPC Break-Even Sales Price Equation 2-2

Where

$LCOE_{CCS}$	= LCOE for given capture plant without transport and storage (2018$/MWh)
$LCOE_{Non\text{-}CCS}$	= LCOE for given reference non-capture plant without transport and storage (2018$/MWh)
CO_2 Captured	= rate of CO_2 captured (tonnes/MWh)

To achieve the break-even sales price in nominal 2018$ for the modeled SCPC electric power plant, all appropriate costs were calculated on a nominal basis per QGESS: Cost Estimation of Power Plant Performance. [32]

The other three CO_2 source types modeled in this analysis were an ethanol production plant, natural gas processing plant, and cement production plant. All have CFs of 85 percent. The ethanol plant and natural gas processing plant have a capture rate of 100 percent, while the cement plant has a capture rate of 95 percent. The specifications for each of these plants were based on work reported in the Industrial Report. [31] A reference plant was chosen for each process in the Industrial Report, and factors for the amount of CO_2 generated per amount of product produced were applied based on literature. All processes were evaluated based on greenfield and retrofit sites, and costs were reported in nominal 2011 dollars (2011$). The amount of CO_2 captured from each of the industrial plants is based on the amount of CO_2 available to capture. The cost metric used in the Industrial Report is the break-even cost of capturing CO_2 (on $/tonne basis), which is the CO_2 selling price that is required for the base plant to recover all of the costs associated with implementing several CO_2 processes and meeting required rate of return on equity; transport and storage costs are not included. [31] Since the Bituminous Baseline Rev4 Report used break-even sales price within its methodology, that metric will also be used to discuss the cost associated with capturing CO_2 from industrial sources. The equation used to calculate the CO_2 break-even sales price for an industrial source is given in Industrial Break-Even Sales Price Equation 2-3 and incorporates capital, operation and maintenance (O&M), consumables, fuel, and purchased power costs that are all divided by the annual CO_2 captured per the CF (tonne/yr).

$$CO_2 \text{ Break} - \text{Even Sales Price} = \frac{\text{Cap} + \text{Fix O\&M} + \text{Var O\&M} + \text{Cons} + \text{Fuel} + \text{PP}}{CO_2\ Captured}$$

Industrial Break-Even Sales Price Equation 2-3

Where

Cap	= capital cost for equipment, contingencies, and fees (2011$)
Fix O&M	= fixed O&M cost for maintenance labor, property taxes and insurance, etc. (2011$)
Var O&M	= variable O&M cost for maintenance material (2011$)
Cons	= cost for consumables such as water treatment, corrosion inhibitor, etc.
Fuel	= cost for purchasing fuel to run certain equipment (2011$)
PP	= cost for purchasing power for certain equipment (2011$)
CO_2 Captured	= annual CO_2 mass at specific plant CF (tonne)

To achieve the break-even sales price in nominal 2018$ for the greenfield sites of the modeled ethanol, cement, and natural gas processing plants, all appropriate costs were calculated on a nominal basis using the methodology within QGESS: Cost Estimation of Power Plant Performance for a natural gas combined cycle plant. [32] The natural gas combined cycle plant methodology, which has a construction period of three years (similar to a retrofit) was assumed for simplicity even though it is apparent that the high purity sources (i.e., ethanol and natural gas processing plants) would more than likely require a shorter construction period for a retrofit. The Chemical Engineering Plant Cost Index was used to adjust capture costs from 2011$ to 2018$. [40]

2.2.2 CO_2 Source Locations

As mentioned above, four CO_2 source types (i.e., ethanol production plant, natural gas processing plant, cement production plant, and SCPC electric power plant) were modeled for this analysis with each considered a hypothetical plant, not an existing plant. To determine their hypothetical locations, all sources within the United States that met the requirements for 45Q tax credits [36] were plotted in Esri's geographic information system (GIS) application ArcGIS Pro v2.5.0 (ArcGIS Pro), [41] using data from the National Carbon Sequestration Database and Geographic Information System. [42] Clusters of the same source type were observed with factors such as volume of CO_2 emissions, regulatory primacy, and state incentives considered when choosing the cluster candidates. Spatial relation across the Central United States study area and variety in CO_2 source types were also considered. Clusters chosen for evaluation were in Iowa (ethanol), Kansas (cement), Minnesota (natural gas processing), Missouri (SCPC), North Dakota (SCPC), South Dakota (cement), and Wyoming (SCPC). The centroids of each of the clusters were determined and that position was the source's location.

2.3 CO_2 STORAGE

Geologic CO_2 storage is considered the last component in the CCS value chain, but a source needs to determine a potential storage site for its captured CO_2 before determining the best way to transport it to that site. Therefore, geologic CO_2 storage is discussed before transportation of CO_2. Geologic CO_2 storage involves injecting CO_2 delivered from a CO_2 source into a suitable geologic storage reservoir for long-term storage. Storage reservoirs located within the Central United States study area were identified and those storage reservoirs outside were considered if they provided an economic storage option. Storage reservoir candidates and their storage costs were determined using a NETL-developed model.

2.3.1 CO_2 Storage Costs

The CO_2 Storage Cost Model, [33] an Excel spreadsheet tool that estimates the revenues and capital, operating, and financing costs of storing CO_2 in a saline reservoir onshore (i.e., within the lower 48 states), was used to determine the storage costs for this analysis. This publicly available model estimates the break-even cost of storing CO_2, which is the lowest cost CO_2 storage operators can charge (in $/tonne) and still achieve their minimum desired return on equity. Costs and financial instruments are incorporated into the model to comply with EPA's Underground Injection Control Class VI regulations. [43] These regulations include requirements for a typical CO_2 storage project timeline such as 30 years of injection operations, followed by 50 years of post-injection site care, and then site closure. The model also includes the technology and equipment needed for compliance with the monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule. [44]

A non-public version of the CO_2 Storage Cost Model was used for this analysis; several updates have been added including real dollar methodology and new storage reservoirs to the geologic database. Certain parameters within the CO_2 Storage Cost Model were changed from their default values (those values already within the publicly available version on NETL's website)[c] to determine the storage costs based on the given scenario (Exhibit 2-2). The scenarios are described more in Section 3.

[c] It is important to note that other values within the model were changed (e.g., recurring periods within the Activity_Inputs sheet and schedule for three-dimensional seismic in Key_Inputs tab) before runs were performed because of more accurate information. These values will more than likely be defaults in the next model posting and are not listed in the key parameters table (Exhibit 3-1).

Exhibit 2-2. Key parameters used in CO_2 Storage Cost Model for this analysis with explanatory text

Parameter	Value	Note
Percent of structures available for storing CO_2 (%)	100	Provides full structure opportunity for storage reservoir
Project start year	2018	Base-year costs in 2008$, escalated to 2018$
CO_2 injected (tonne/yr)	Based on capture rate	Assumed all the CO_2 captured is injected; equal to the source's capture rate (Exhibit 3-1)
CO_2 multiplier	1.18	Represents CF of 85 percent, which matches CF of CO_2 sources modeled in this analysis
Well spacing above seal (mi^2/well)	4	In uncertainty area
Max number of wells in reservoir	0	In uncertainty area
Minimum number of wells at start dual completed	2	In uncertainty area
Nominal maximum surface area for injection project (mi^2)	1,000	Maximum surface area setting is for institutional limitation, which assumes the CO_2 plume uncertainty area never exceeds 1,000 mi^2
Percent equity (remainder is debt) (%)	40	Based on values from the largest natural gas storage companies; nominal rates
Cost of equity (%)	13	
Cost of debt (%)	6	
Tax rate (federal and state) (%)	27	Includes federal (21 percent) and state (6 percent) taxes with no deduction assumed on state taxes against federal taxes
Annual tax rate (percent of investment income, net administrative fees) for Trust Fund (%)	27	Matches overall tax rate
Casing inspection log above seal ($/well and $/ft/well)	2,070 and 4.15	Costs included for above seal well and converting stratigraphic well to above seal

Storage break-even costs can be estimated for a storage reservoir in one or each of the formations posted to the model's geologic database. The geologic database in the version of the CO_2 Storage Cost Model used for this analysis contains geographical and geological data for 87 formations that are partitioned into 275 distinct storage reservoirs scattered across 36 basins in 27 states. Geologic properties, such as formation depth, thickness, porosity, and permeability, are included within the database. These properties are specific to each storage reservoir and directly impact the break-even cost of storage ($/tonne CO_2). The geologic characteristics of each storage reservoir are outlined in Exhibit 3-2. Storage reservoirs can also be further divided into different structure settings (like anticline, dome, and regional dip). Storage costs are usually lower for dome structure primarily due to a better storage coefficient associated with structural closure (Exhibit 3-2). This higher storage coefficient reduces the overall areal extent of the CO_2

plume lowering storage cost. Storage reservoirs within the CO_2 Storage Cost Model's geologic database contain a centroid that serves as a spatially representative location of each given storage reservoir. As part of this analysis, the centroid is the assumed location of the storage operations in a given storage reservoir regardless of the areal extent of each storage reservoir. Each storage reservoir centroid within the CO_2 Storage Cost Model was derived through a common approach and, therefore, provides a consistent point of reference for assuming storage site locations.

There are three key factors that drive storage costs: 1) mass of CO_2 injected, 2) quality of the storage reservoir, and 3) areal extent of the CO_2 plume. [5] [24] The lower the rate of injection, the higher the storage costs, which, in turn, are affected by geologic properties (i.e., storage reservoir quality) and CO_2 plume areal extent. The thickness and permeability of a storage reservoir affects injectivity, which, in turn, influences the number of injection wells needed and costs for drilling, operating, and plugging. Reservoir depth also impacts the drilling and operational costs of injection and monitoring wells with deeper wells being more expensive than shallower wells. Taking into account the geologic properties of a storage reservoir, a storage reservoir with a higher-quality rating provides a lower storage cost than a storage reservoir with a lower-quality rating (Exhibit 3-4). The areal extent of the CO_2 plume is proportional to the CO_2 injection rate and inversely proportional to storage reservoir quality. It is a critical cost driver to monitoring costs with respect to the number of monitoring wells to be drilled, extent of seismic data acquisition, and distribution of other monitoring technology. [5] A larger CO_2 plume would require a larger monitoring area and a more extensive monitoring, verification, and accounting program, thus, increasing costs.

2.3.2 CO_2 Storage Reservoir Candidates

To determine the storage reservoirs for this analysis, all 275 saline storage reservoirs within the CO_2 Storage Cost Model's database were run with the injection rate of the SCPC power plant (4.33 Mt/yr). The results were then filtered two different ways, to determine which saline storage reservoirs were of the highest quality within each basin and to determine the lowest storage cost option within each basin. Each result returned a list of 38 individual storage reservoirs and provided a total of 48 unique storage reservoirs between the two. Some storage reservoirs were both the lowest storage cost and best quality within the basin. Both dome and regional dip structure types were evaluated. Of those storage reservoirs with the lowest cost, 35 of the 38 were dome structures. All 38 storage reservoirs with the best storage reservoir quality were also dome structures. The 48 unique storage reservoirs were then plotted on a U.S. map along with the seven CO_2 source locations that were chosen. The storage reservoirs were then narrowed down further to those that were located within or near the chosen study area. Storage reservoirs that were both near and far away from the CO_2 sources were also considered to give a range of storage options and transport distances. If a storage reservoir was close in cost and storage reservoir quality to the best in the basin, and the location permitted for a more complete analysis, it was added to the list for consideration (see Section 3.1 for more information). From there, eight final storage reservoirs were chosen. These storage reservoirs were spread throughout and near the study area ensuring an optimal transport network could be modeled from each CO_2 source to an appropriate sink and allowing for a thorough CCS cost analysis of the Central United States.

2.4 CO_2 TRANSPORT

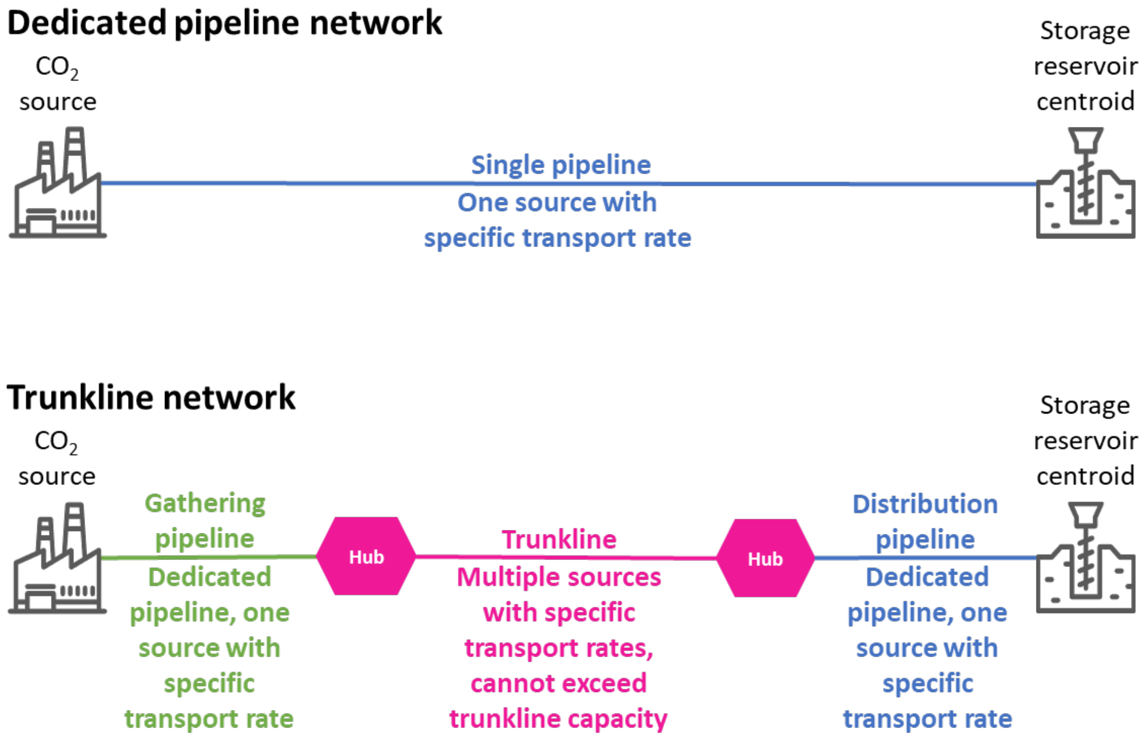
Transport is considered the second component in the CCS value chain because it connects a CO_2 source to a storage site. However, a source has to consider a potential storage site to store its captured CO_2 before determining the best transportation option. Therefore, the transportation of CO_2 is discussed after geologic storage of CO_2 and, thus, provides the final piece to an integrated CCS system. Captured CO_2 from fossil fuel-fired power generation facilities or industrial plants is transported via a pipeline to a geologic storage site for storage in a saline storage reservoir. Two transportation networks and their appropriate costs were designed/modeled in this analysis using software programs and a NETL-developed model.

2.4.1 CO_2 Transportation Networks

In this analysis, two conceptual transportation networks were modeled—dedicated pipeline network and trunkline network—to provide options for a CO_2 source depending on its location and mass of CO_2 requiring transport. Both networks follow the same ROW for existing natural gas pipeline infrastructure per EIA's natural gas pipeline data. [45] This data was plotted in ArcGIS Pro, [41] and each pipeline path followed the shortest transport distance of the existing natural gas pipeline infrastructure to connect a CO_2 source to a saline storage reservoir. Since the CO_2 source locations are arbitrary points, small pipeline segments were created from the existing natural gas pipeline to the CO_2 source if current infrastructure was not already present in the area. The same concept was completed for the saline storage reservoirs. Additionally, if two routes were approximately the same distance, the route that allowed for the most simplistic network design was chosen. As previously mentioned, the Central United States study area was broken into three regional impact areas (discussed in more detail in Section 3.2)—Central Impact Area, Northwest Impact Area, and Gulf Impact Area. Therefore, a specific dedicated pipeline network and trunkline network were established in each regional impact area.

The first transportation network analyzed was a dedicated pipeline network. A dedicated pipeline network uses a single pipeline to transport CO_2 from an individual CO_2 source directly to a single saline reservoir (i.e., reservoir centroid). For example, if the ethanol plant used in this analysis wants to transport its annual production of CO_2 (0.12 Mt) (Exhibit 3-1) to Minnelusa 2 using the dedicated pipeline network, the CO_2 would be directly sent via a dedicated pipeline to the Minnelusa 2 storage reservoir for storage. The trunkline network, the second transportation network analyzed, follows the same path as the dedicated pipeline network in each regional impact area but is made up of three different pipelines—a gathering pipeline, trunkline, and distribution pipeline. The pipeline distance for both the gathering and distribution pipelines were assumed to be 30 miles (mi) to emphasize the benefit of a trunkline. Also, these pipelines are considered dedicated pipelines since they only have the capacity to transport CO_2 from one specific source. At the end of each gathering pipeline and beginning of each distribution pipeline is a hub (referred to as gathering hub and distribution hub, respectively) that is 30 mi from the source or storage reservoir. The hubs are connected by the trunkline. Hubs located on a trunkline were ignored so that a trunkline just connected the gathering hub and distribution hub and no other trunklines were modeled in between. For example, when the ethanol plant transports CO_2 to Lance 1, the trunkline passes through the distribution hub for Maha 01 (HNE1). HNE1 was ignored, so only a single trunkline segment, instead of two, connected HIA to HWY2. The gathering hubs modeled in this analysis include HIA (Iowa) and HMN (Minnesota) in the Central Impact Area; HND1 (North Dakota), HSD (South Dakota), and HWY1 (Wyoming) in the Northwest Impact Area; and HMO (Missouri) and HKS1 (Kansas) in the Gulf Impact Area. The remaining hubs in each network are distribution hubs. Because hubs connect multiple sources or pipeline networks, unlike the gathering and distribution pipelines, the trunkline has the capacity to transport CO_2 from multiple sources, thus, lowering transportation unit costs. To cover a range of CO_2 transport rates from sources, trunkline capacities ranging 0.10–40 Mt/yr were modeled to see changes in various parameters. Ultimately, four trunkline capacities (i.e., 4.50 Mt/yr, 7.50 Mt/yr, 18.50 Mt/yr, and 40.00 Mt/yr) were chosen for this analysis that provided a range of trunkline diameter sizes, costs, and number of booster pumps. If the ethanol plant used in this analysis utilized a trunkline network with a capacity of 40 Mt/yr to transport its annual production of CO_2 (0.12 Mt) to Minnelusa 2, the 0.12 Mt/yr of CO_2 would be transported from the source through its own dedicated gathering pipeline to a gathering hub (i.e., HIA). Then, it would be transported via trunkline, where it is combined with CO_2 produced from other sources without going over the maximum trunkline capacity, to a distribution hub (i.e., HMT1). At the distribution hub, the annual CO_2 produced from the ethanol plant (0.12 Mt) is removed and transported via a dedicated distribution pipeline to the Minnelusa 2 storage reservoir. A map illustrating the overall dedicated pipeline networks and trunkline networks (the integrated CCS system) for each regional impact area is shown in Exhibit 3-6. The concepts (Exhibit 2-3) of the dedicated pipeline network and trunkline network (e.g., assuming gathering and distribution lines are dedicated pipelines, including certain components to compose pipeline networks) were based on those used in the 2018 Grant et al. study. [24]

Exhibit 2-3. Schematics depicting dedicated pipeline network concept (top) and trunkline network concept (bottom) used in this analysis



2.4.2 CO_2 Transport Costs

Transportation costs for the dedicated pipeline network and trunkline network were determined using the CO_2 Transport Model, [34] which is an Excel spreadsheet tool that estimates the revenues and capital, operating, and financing costs of transporting dense phase liquid CO_2 via pipeline. This publicly available model calculates the break-even cost of transporting CO_2 (in $/tonne) based on the length of the pipeline and mass of CO_2 transported. A source's CO_2 is delivered to the transportation network in compliance with pipeline purity specifications, so CO_2 treatment costs are included under the capture portion. A modified version of the 2018 publicly available CO_2 Transport Cost Model was used for this analysis. [34]

To determine the transport costs for both transportation networks, certain parameters within the CO_2 Transport Cost Model were changed from their default values based on the given scenario (Exhibit 2-4). The scenarios are described in more detail in Section 3.

Exhibit 2-4. Key parameters used in CO_2 Transport Cost Model for this analysis with explanatory text

Parameter	Value	Note
CO_2 transported (on average) (Mt/yr)	Based on capture rate and trunkline capacity	Equal to the source's capture rate and trunkline capacity (Exhibit 2-6)
Pipeline length (mi)	Based on pipeline/trunkline segments	Distances for pipeline/trunkline segments in the dedicated pipeline network and trunkline network can be found in Exhibit 2-5 and Exhibit 2-6, respectively
Elevation change (ft)	Based on pipeline/trunkline segment	Equal to the elevation at the destination minus the elevation at the origin (Exhibit 2-5 and Exhibit 2-6)
Percent equity (remainder is debt) (%)	40	Based on values from the largest natural gas transport companies; nominal rates
Cost of equity (%)	13	
Cost of debt (%)	6	
Tax rate (federal and state) (%)	27	Includes federal (21 percent) and state (6 percent) taxes with no deduction assumed on state taxes against federal taxes
Project start year	2018	Base-year costs in 2011$, escalated to 2018$
Capacity factor (%)	85	Matches CF of CO_2 sources modeled in this analysis
Method for calculating inside diameter	Massachusetts Institute of Technology	Does not account for the influence of elevation, which is why it is able to handle large elevation deltas

Supplementary information provided in Exhibit 2-4, Exhibit 2-5, and Exhibit 2-6 displays the annual tonnes of CO_2 transported (referred to as pipeline/trunkline capacity), pipeline/trunkline distance, and elevation change for the dedicated pipeline network and trunkline network for incorporation into the model. The pipeline/trunkline segments represent the path origin and destination (i.e., CO_2 source to storage reservoir for dedicated pipeline network and CO_2 source to gathering hub, gathering hub to distribution hub, or distribution hub to storage reservoir for the trunkline network). Abbreviations are used in the exhibits for simplicity with their definitions given in the note under each.

Exhibit 2-5. Pipeline distance and elevation data of pipeline segments in dedicated pipeline network by regional impact area for CO_2 Transport Cost Model runs in this analysis

Regional Impact Area	Pipeline Segment	Pipeline Distance (mi)	Elevation Change (ft)
Central	ET-MI2	958	2,540
	ET-LA1	880	4,530
	ET-RR1	695	710
	ET-MA01	585	2,760
	ET-AR4	487	1,000
	ET-WO1	1,004	-685
	ET-FR3A	1,099	-1,105
	ET-MS3	480	-535
	NGPP-MI2	722	2,680
	NGPP-LA1	1,073	4,670
	NGPP-RR1	460	850
	NGPP-MA01	777	2,900
	NGPP-AR4	680	1,140
	NGPP-WO1	1,196	-545
	NGPP-FR3A	1,292	-965
	NGPP-MS3	526	-395
NW	CE_SD-MI2	302	795
	CE_SD-LA1	455	2,785

Regional Impact Area	Pipeline Segment	Pipeline Distance (mi)	Elevation Change (ft)
NW	CE_SD-RR1	415	-1,035
	CE_SD-MA01	545	1,015
	SCPC_WY-MI2	336	-5,680
	SCPC_WY-LA1	191	-3,690
	SCPC_WY-RR1	541	-7,510
	SCPC_WY-MA01	222	-5,460
	SCPC_ND-MI2	393	1,725
	SCPC_ND-LA1	546	3,715
	SCPC_ND-RR1	30	-105
	SCPC_ND-MA01	636	1,945
Gulf	CE_KS-AR4	291	1,330
	CE_KS-WO1	488	-355
	CE_KS-FR3A	584	-775
	CE_KS-MS3	457	-205
	SCPC_MO-AR4	292	1,145
	SCPC_MO-WO1	632	-540
	SCPC_MO-FR3A	728	-960
	SCPC_MO-MS3	328	-390

Note: For simplicity, abbreviations for the regional impact areas and components of pipeline segments are used within the tables. Definitions are AR4 = Arbuckle 4 storage reservoir, CE_KS = cement production plant in Kansas, CE_SD = cement production plant in South Dakota, Central = Central Impact Area, ET = ethanol production plant, FR3A = Frio 3a storage reservoir, Gulf = Gulf Impact Area, LA1 = Lance 1 storage reservoir, MA01 = Maha 01 storage reservoir, MI2 = Minnelusa 2 storage reservoir, MS3 = Mt. Simon 3 storage reservoir, NGPP = natural gas processing plant, NW = Northwest Impact Area, RR1 = Red River 1 storage reservoir, SCPC_MO = SCPC electric power plant in Missouri, SCPC_ND = SCPC electric power plant in North Dakota, SCPC_WY = SCPC electric power plant in Wyoming, and WO1 = Woodbine 1 storage reservoir.

Exhibit 2-6. Distance and elevation data of pipeline/trunkline segments in trunkline network by regional impact area for CO_2 Transport Cost Model runs in this analysis

<table>
<tr><th>Regional Impact Area</th><th>Pipeline/Trunkline Segment</th><th>Line Type</th><th>Pipeline/Trunkline Distance (mi)</th><th>Elevation Change (ft)</th><th>Pipeline/Trunkline Capacity (Mt/yr)</th></tr>
<tr><td rowspan="26">Central</td><td>ET-HIA</td><td rowspan="2">Gathering</td><td rowspan="2">30</td><td>-135</td><td>0.12</td></tr>
<tr><td>NGPP-HMN</td><td>25</td><td>0.55</td></tr>
<tr><td>HIA-HMT1</td><td rowspan="16">Trunkline</td><td>898</td><td>2,235</td><td rowspan="16">4.50
7.50
18.50
40.00</td></tr>
<tr><td>HIA-HWY2</td><td>820</td><td>5,185</td></tr>
<tr><td>HIA-HND2</td><td>635</td><td>865</td></tr>
<tr><td>HIA-HNE1</td><td>525</td><td>2,580</td></tr>
<tr><td>HIA-HKS2</td><td>427</td><td>955</td></tr>
<tr><td>HIA-HTX1</td><td>944</td><td>-510</td></tr>
<tr><td>HIA-HTX2</td><td>1,039</td><td>-880</td></tr>
<tr><td>HIA-HIL1</td><td>420</td><td>-295</td></tr>
<tr><td>HMN-HMT1</td><td>662</td><td>2,215</td></tr>
<tr><td>HMN-HWY2</td><td>1,013</td><td>5,165</td></tr>
<tr><td>HMN-HND2</td><td>400</td><td>845</td></tr>
<tr><td>HMN-HNE1</td><td>717</td><td>2,560</td></tr>
<tr><td>HMN-HKS2</td><td>620</td><td>935</td></tr>
<tr><td>HMN-HTX1</td><td>1,136</td><td>-530</td></tr>
<tr><td>HMN-HTX2</td><td>1,232</td><td>-900</td></tr>
<tr><td>HMN-HIL1</td><td>466</td><td>-315</td></tr>
<tr><td>HMT1-MI2</td><td rowspan="8">Distribution</td><td rowspan="11">30</td><td>440</td><td rowspan="8">0.12
0.55</td></tr>
<tr><td>HWY2-LA1</td><td>-520</td></tr>
<tr><td>HND2-RR1</td><td>-20</td></tr>
<tr><td>HNE1-MA01</td><td>315</td></tr>
<tr><td>HKS2-AR4</td><td>180</td></tr>
<tr><td>HTX1-WO1</td><td>-40</td></tr>
<tr><td>HTX2-FR3A</td><td>-90</td></tr>
<tr><td>HIL1-MS3</td><td>-105</td></tr>
<tr><td rowspan="6">NW</td><td>CE_SD-HSD</td><td rowspan="3">Gathering</td><td>775</td><td>0.97</td></tr>
<tr><td>SCPC_WY-HWY1</td><td>-4,460</td><td rowspan="2">4.33</td></tr>
<tr><td>SCPC_ND-HND1</td><td>165</td></tr>
<tr><td>HSD-HMT2</td><td rowspan="3">Trunkline</td><td>242</td><td>330</td><td rowspan="3">4.50
7.50
18.50
40.00</td></tr>
<tr><td>HSD-HWY2</td><td>395</td><td>2,530</td></tr>
<tr><td>HSD-HND3</td><td>355</td><td>-1,700</td></tr>
</table>

Regional Impact Area	Pipeline/Trunkline Segment	Line Type	Pipeline/Trunkline Distance (mi)	Elevation Change (ft)	Pipeline/Trunkline Capacity (Mt/yr)
NW	HSD-HNE2	Trunkline	485	390	4.50 7.50 18.50 40.00
	HWY1-HMT2		276	-910	
	HWY1-HWY2		131	1,290	
	HWY1-HND3		481	-2,940	
	HWY1-HNE2		162	-850	
	HND1-HMT2		334	1,870	
	HND1-HWY2		487	4,070	
	HND1-HND3		39	-160	
	HND1-HNE2		577	1,930	
	HMT2-MI2	Distribution	30	-310	0.97 4.33
	HWY2-LA1			-520	
	HND3-RR1			-110	
	HNE2-MA01			-150	
Gulf	CE_KS-HKS1	Gathering		60	0.97
	SCPC_MO-HMO			-145	4.33
	HKS1-HKS3	Trunkline	231	1,330	4.50 7.50 18.50 40.00
	HKS1-HTX1		428	-375	
	HKS1-HTX2		524	-745	
	HKS1-HIL2		397	-280	
	HMO-HKS4		232	1,050	
	HMO-HTX1		572	-355	
	HMO-HTX2		668	-725	
	HMO-HIL2		268	-260	
	HKS3-AR4	Distribution	30	-60	0.97
	HKS4-AR4			240	4.33
	HTX1-WO1			-40	0.97 4.33
	HTX2-FR3A			-90	
	HIL2-MS3			15	

Note: For simplicity, abbreviations for the regional impact areas and components of pipeline/trunkline segments are used within the tables. Only abbreviations different than those defined for Exhibit 2-5 are defined. Definitions are HIA = gathering hub in Iowa for ethanol production plant, HIL1 and HIL2 = distribution hubs in Illinois for Mt. Simon 3 storage reservoir, HKS1 = gathering hub in Kansas for cement production plant; HKS2, HKS3, and HKS4 = distribution hubs in Kansas for Arbuckle 4 storage reservoir, HMN = gathering hub in Minnesota for NGPP, HMO = gathering hub in Missouri for SCPC electric power plant, HMT1 and HMT2 = distribution hubs in Montana for Minnelusa 2 storage reservoir, HND1 = gathering hub in North Dakota for SCPC electric power plant, HND2 and HND3 = distribution hubs in North Dakota for Red River 1 storage reservoir, HNE1 and HNE2 = distribution hub in Nebraska for Maha 01 storage reservoir, HSD = gathering hub in South Dakota for cement production plant, HTX1 = distribution hub in Texas for Woodbine 1 storage reservoir, HTX2 = distribution hub in Texas for Frio 3a storage reservoir, HWY1 = gathering hub in Wyoming for SCPC electric power plant, HWY2 = distribution hub in Wyoming for Lance 1 storage reservoir.

Concepts of obtaining transport costs for the dedicated pipeline network and trunkline pipeline network were based on those used in the 2018 Grant et al. study. [24] Pipeline segments were summed for a total distance to be modeled for transport cost in the dedicated pipeline network, while each segment was modeled separately from the gathering pipeline to the distribution pipeline in the trunkline network. The transport cost for each segment was then summed to determine the total transport cost for a trunkline network (see Exhibit D-2 for example).

There are five key factors that drive transport costs: 1) mass of CO_2 transported; 2) length of pipeline; 3) change in elevation between CO_2 sources, hubs (trunkline network only), and storage reservoirs; 4) number of booster pumps required to maintain pressure and transport CO_2 from source to sink; and 5) diameter of pipeline, which is determined by the mass of CO_2 transported and transport distance. [5] [24] A lower transport rate causes an increase in transport costs. Transport costs are higher for a longer pipeline due to the increase in material and labor costs associated with a longer pipeline. Elevation delta increases transport costs when the delta is positive since more booster pumps are required for the greater terrain change. Booster pumps are needed to sustain pressure throughout the pipeline in order to meet outlet pressure specifications. They complement the pipeline diameter. For each pipeline diameter, a higher amount of CO_2 transported requires additional booster pumps to further compress the CO_2, thus, affecting transport costs. The CO_2 Transport Cost Model determines the lowest cost option between increasing pipeline diameter or adding booster pumps with increasing annual mass of CO_2. [46] When pipeline diameter increases (e.g., from 8 in. to 12 in.), the number of booster pumps required decreases.

3 Modeling Scenarios

As discussed in Section 2.1, this study evaluated management options a CO_2 source faces when determining where to store its captured CO_2 in the Central united States, from both an economic and geologic perspective. In order to explore the challenges and advantages of different areas within the region, the Central Unite States was divided into three regional impact areas and an integrated CCS network assessment was done using regionally-relevant CO_2 sources and storage options. Costs for each CCS value chain component were modeled for sources within these three regional impact areas to find the lowest CCS cost source-to-sink combination.

3.1 Sources, Storage Reservoirs, and Transportation Options

Costs for each CCS value chain component were calculated for four hypothetical CO_2 sources with 85 percent CFs and annual capture rates between 0.12 Mt CO_2 and 4.33 Mt CO_2 over a 30-year capture and injection period (Exhibit 3-1). These types of CO_2 sources were chosen because of their abundance within the region and their qualification for 45Q tax credits (to complement the supplementary 45Q study). [29] Seven hypothetical source locations were modeled based on the methodology described in Section 2.2.2. These locations provided a range of transport distance and storage options for each source.

Exhibit 3-1. Key items associated with CO_2 sources modeled in this analysis

CO_2 Source	Reported Net Power or Product Output	CO_2 Captured 85% CF (Rounded) Mt/yr	CO_2 Break-Even Sales Price 2018$/tonne
Natural gas processing plant	500 MMscf/d	0.55	20.92
Ethanol production plant	50 M gal/yr	0.12	35.22
SCPC electric power plant	650 MW_e	4.33	65.50
Cement production plant	992,500 tonnes/yr	0.97	106.48

Note: Annual CO_2 captured represents the amount of CO_2 captured at 85 percent CF. The CO_2 break-even sales price is associated with the greenfield site of the electric power plant and industrial plants.

Eight storage reservoirs from the geologic database in the CO_2 Storage Cost Model [33] were chosen as storage options for the CO_2 sources modeled in this analysis based on methodology described in Section 2.3.2 (Exhibit 3-2): Minnelusa 2 (MI2), Lance 1 (LA1), Red River 1 (RR1), Maha 01 (MA01), Arbuckle 4 (AR4), Woodbine 1 (WO1), Frio 3a (FR3A), and Mount (Mt.) Simon 3 (MS3). Dome and regional dip structural settings were considered for each reservoir. Three of the storage reservoirs are located within the northern portion of the study area and two are located centrally. There are also two storage reservoirs within the southern portion of the study area and one outside. Minnelusa 2 is in the Powder River Basin in southeastern Montana, Lance 1 is in the Wind River Basin in central Wyoming, and Red River 1 is in the Williston Basin in western North Dakota. Maha 01 is in the Denver Basin in western Nebraska, while Arbuckle 4 is in the Ozark Plateau Basin in southwestern Kansas. Woodbine 1 is in the East Texas Basin and

Frio 3a is in the Gulf Coast Onshore Basin; both are in eastern Texas. Mt. Simon 3 is right outside the study area within the Illinois Basin in central Illinois. It was included since it provides a relatively high-quality storage option at a low cost and is located relatively close to some of the modeled CO_2 sources. Some of these storage reservoir-basin combinations (i.e., Red River 1–Williston, Woodbine 1–East Texas, and Mt. Simon 3–Illinois) align with those that were evaluated within NETL's "QGESS: Carbon Dioxide Transport and Storage Costs in NETL Studies" [47] demonstrating the consistency in the methodology used among NETL energy system studies to achieve low cost storage options for a CO_2 source. The eight storage reservoirs were selected because they represent the lowest storage cost option and/or best storage reservoir in regard to storage reservoir quality within their respective basins. Also, they vary in terms of their locations from the CO_2 sources. The Frio 3a storage reservoir is not the best quality or lowest cost storage option within the Gulf Coast Onshore Basin (Frio 7a was slightly better in quality, while Frio 2 was slightly lower in cost); however, it provides a good-quality reservoir at a low storage cost without having to travel the extra distance to Frio 2 or Frio 7a. Therefore, it was chosen instead of the Frio 2 or Frio 7a storage reservoirs to evaluate. The storage reservoir identifier (ID) shown in Exhibit 3-2 is used in tables and charts throughout this report for simplicity.

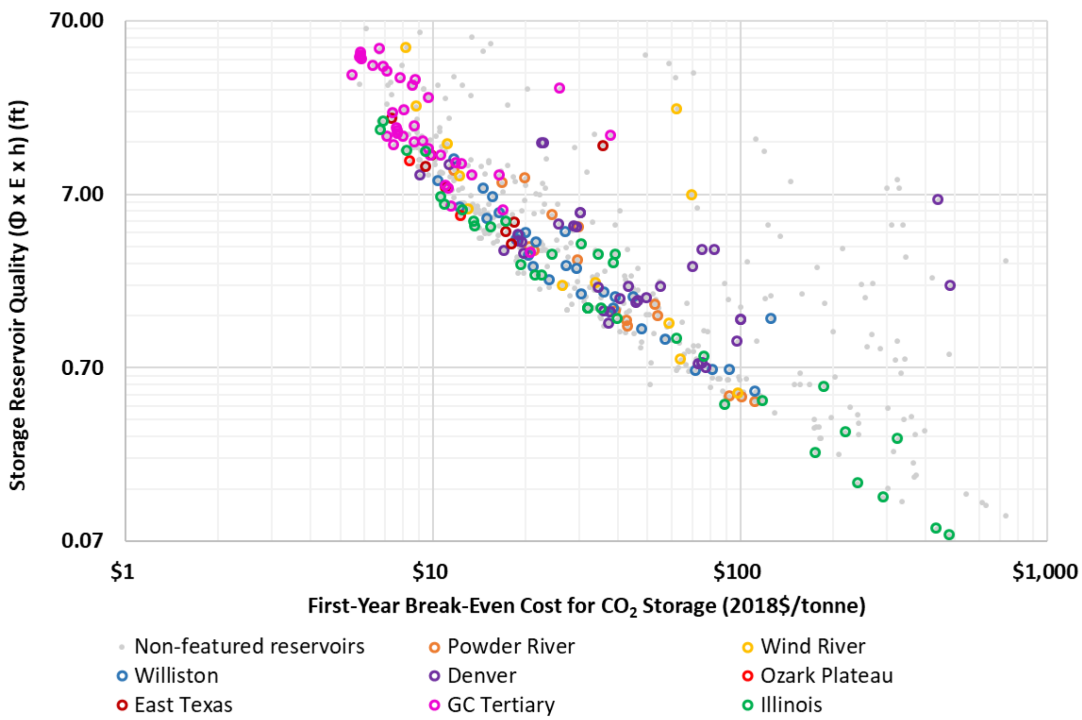
Exhibit 3-2. Geologic characteristics associated with eight storage reservoirs evaluated in this analysis

Formation	Storage Reservoir ID	Depth (ft)	Thickness (ft)	Porosity (%)	Permeability (mD)	Storage Coefficient (%)	
						Dome	Regional Dip
Minnelusa	MI2	8,000	295	19.0	200	17.19	6.19
Lance	LA1	7,394	1,648	17.5	16	16.97	4.71
Red River	RR1	9,000	530	14.0	39	15.01	7.34
Maha	MA01	3,800	274	21.4	100	15.28	5.63
Arbuckle	AR4	5,365	720	10.0	50	15.01	7.34
Woodbine	WO1	5,500	700	20.0	500	13.73	5.43
Frio	FR3A	5,000	1,000	30.0	460	15.28	5.63
Mt. Simon	MS3	4,270	1,000	12.0	125	15.28	5.63

Each formation in each basin modeled for this report is divided into sub-areas. For example, the Mt. Simon formation is present in the Inter-Basin Arch, Michigan, and Illinois basins and is divided into 11 sub-areas (e.g., Mt. Simon 3, which is in the Illinois Basin). The Mt. Simon 3 sub-area has a large areal extent with the potential for development of multiple CO_2 storage reservoirs of similar costs. Modeling a storage project in the Mt. Simon 3 sub-area is modeling a single storage reservoir, the Mt. Simon 3 storage reservoir, that has the height, porosity, permeability, and storage coefficient unique to the Mt. Simon 3 sub-area, as posted in the model's database. For this report, formation will be used to define the overall formation (e.g., entire Mt. Simon), while storage reservoirs will possess the same name as the sub-areas for which they are modeled (e.g., Mt. Simon 3 storage reservoir for Mt. Simon 3 sub-area).

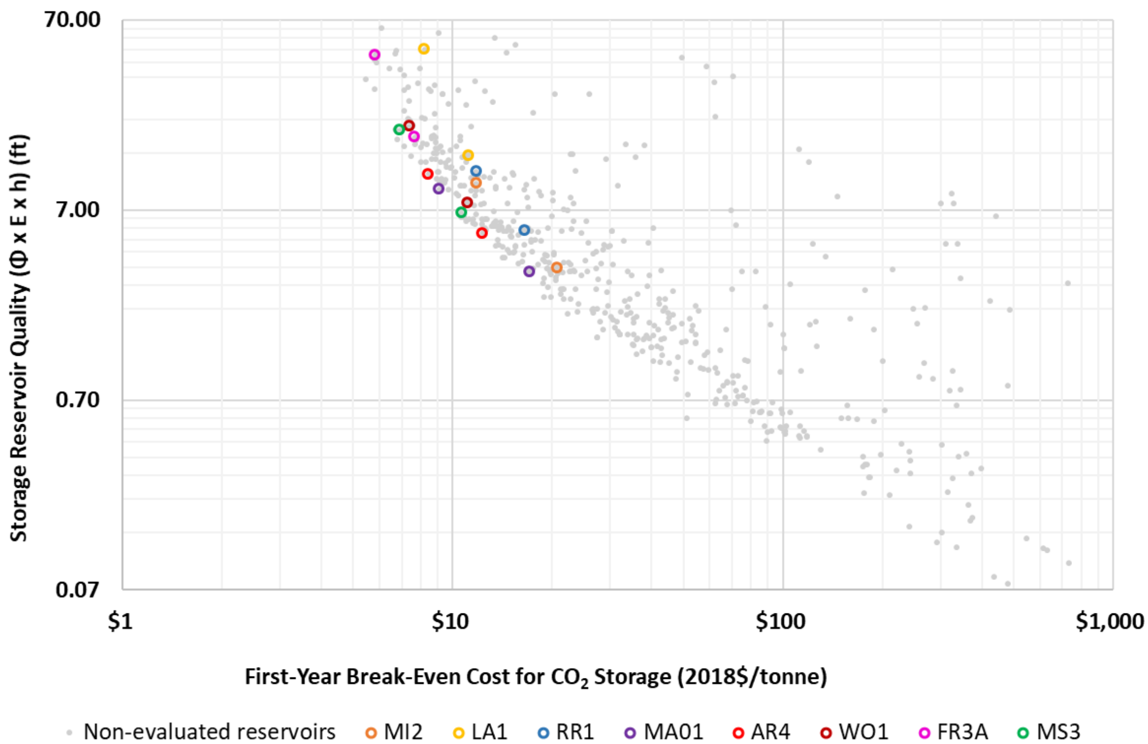
Storage costs reflect storage reservoir quality and the mass of CO_2 injected over the life of the project. The cross plots in Exhibit 3-3 and Exhibit 3-4 plot storage reservoir quality against first-year break-even cost for CO_2 storage on a log scale with Exhibit 3-3 highlighting the basins of the selected storage reservoirs and Exhibit 3-4 highlighting the selected storage reservoirs. Data plotted reflects modeling the SCPC plant with a 4.33 Mt/yr capture rate. The quality index of the storage reservoirs is the product of storage reservoir porosity (ϕ), storage coefficient (E), and storage reservoir height (h). An inverse linear relationship is observed between the two variables; as the quality of the storage reservoir increases, the break-even cost decreases. Additionally, economies of scale factor into a storage site's break-even cost. A storage site that injects a larger volume of CO_2 over the lifetime of a project, will have a lower $/tonne of CO_2 break-even cost. The annual volume of CO_2 injected into the storage reservoir is dependent on the amount of CO_2 captured from the associated CO_2 source. Therefore, larger plants can store a higher volume of CO_2 at a lower break-even cost than plants that capture a smaller volume of CO_2.

Exhibit 3-3. Storage reservoir quality against CO_2 break-even storage cost for SCPC plant (4.33 Mt/yr capture rate) highlighting basins of selected storage reservoirs in dome and regional dip structural settings



The modeled formations are within eight separate basins. The better formations are represented by the lower cost, higher storage value data points (i.e., Frio 3a) while high cost, low storage value data points represent less desirable formations (i.e., Maha 01). The eight storage reservoirs selected for this analysis are shown in Exhibit 3-4 with each reservoir having two data points representing the two structures modeled for this analysis. The lower-cost, higher reservoir-quality value data point for a given storage reservoir is the dome structural setting, while the other is the regional dip structural setting.

Exhibit 3-4. Storage reservoir quality against CO_2 break-even storage cost for SCPC plant (4.33 Mt/yr capture rate) in dome and regional dip structures



To connect the CO_2 sources with a storage reservoir in a dome or regional dip structural settings, two hypothetical CO_2 transportation options—dedicated pipeline or trunkline—were evaluated in this analysis. These two transportation options were chosen because depending on the amount of CO_2 transported and distance from storage reservoirs, they can provide different cost benefits.

3.2 Regional Impact Areas and Scenarios

Capture, storage, and transport costs were combined to evaluate integrated CCS costs for different CO_2 source, storage, and transport combinations. With seven source locations, eight storage reservoirs in two structural settings, and two transportation options, there were over 100 scenarios for evaluation. As mentioned before, to help simplify results for these combinations and highlight the challenges/benefits a CO_2 source faces based on its location within the region, the study area was broken down into three regional impact areas: Central Impact Area, Northwest Impact Area, and Gulf Impact Area. A high-level overview of the CCS network scenarios within each regional impact area is shown in Exhibit 3-5.

Exhibit 3-5. Overall CCS network scenarios by regional impact areas within Central United States

Parameter	Central Impact Area	Northwest Impact Area	Gulf Impact Area

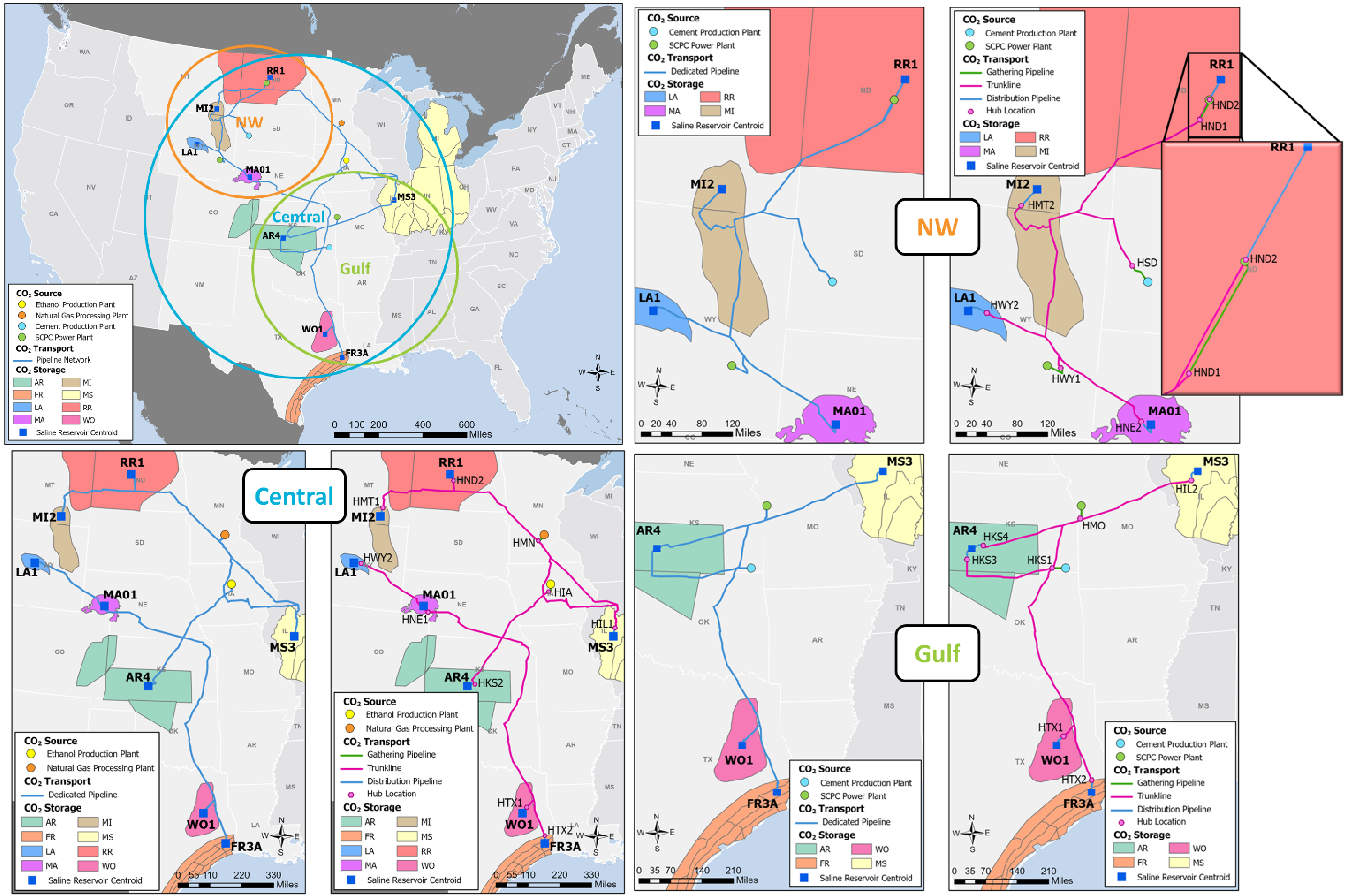
<table>
<tr><td>Geographic Span (States)</td><td colspan="2">Widespread
(Illinois, Iowa, Kansas, Minnesota, Montana, Nebraska, North Dakota, Oklahoma, Texas, and Wyoming)</td><td>Localized
(Montana, Nebraska, North Dakota, South Dakota, and Wyoming)</td><td>Localized
(Illinois, Kansas, Missouri, Oklahoma, and Texas)</td></tr>
<tr><td>CO_2 Source</td><td colspan="2">Ethanol plant (Iowa)
NGPP (Minnesota)</td><td>Cement plant (South Dakota)
SCPC power plant (2) (North Dakota and Wyoming)</td><td>Cement plant (Kansas)
SCPC power plant (Missouri)</td></tr>
<tr><td>Annual CO_2 Capture Rate (Mt)</td><td colspan="2">0.12
0.55</td><td>0.97
4.33</td><td>0.97
4.33</td></tr>
<tr><td>Storage Reservoir</td><td>MI2
LA1
RR1
MA01</td><td>AR4
WO1
FR3A
MS3</td><td>MI2
LA1
RR1
MA01</td><td>AR4
WO1
FR3A
MS3</td></tr>
<tr><td>Storage Structural Setting</td><td colspan="2">Dome
Regional dip</td><td>Dome
Regional dip</td><td>Dome
Regional dip</td></tr>
<tr><td>Transportation Network</td><td colspan="2">Dedicated pipeline
Trunkline</td><td>Dedicated pipeline
Trunkline</td><td>Dedicated pipeline
Trunkline</td></tr>
<tr><td>Annual Mass of CO_2 Transported in Gathering and Distribution Pipelines (Mt)</td><td colspan="2">0.12
0.55</td><td>0.97
4.33</td><td>0.97
4.33</td></tr>
<tr><td>Annual Trunkline Capacity (Mt)</td><td colspan="2">4.50
7.50
18.50
40.00</td><td>4.50
7.50
18.50
40.00</td><td>4.50
7.50
18.50
40.00</td></tr>
<tr><td>Total Scenarios</td><td colspan="2">Dedicated pipeline: 32
Trunkline: 128</td><td>Dedicated pipeline: 24
Trunkline: 96</td><td>Dedicated pipeline: 16
Trunkline: 64</td></tr>
</table>

Each regional impact area was chosen because of the options and challenges/benefits it provides to the CO_2 sources within that specific area. The Central Impact Area has either no or sporadic local storage reservoirs for the sources within the region even though there are clusters of different source types that would require permanent storage, the majority of them being smaller sources (i.e., those with lower CO_2 capture rates); a small capture rate already provides a disadvantage to costs. For example, there is a large cluster of ethanol plants in Iowa and Nebraska, an area that does not have any local reservoirs. Therefore, an ethanol plant, which according to Exhibit 3-1 has a capture rate of 0.12 Mt/yr, in either of these states would have to transport its captured CO_2 over a larger distance to a desirable storage reservoir. The distance as well as the small capture rate for transport and storage would provide larger costs for this source even with its low cost of capture. Even though this impact area covers all eight storage reservoirs, it is the location of the CO_2 sources within Iowa and Nebraska and the types of sources chosen that provide the CCS challenges for this region.

The Northwest Impact Area provides a benefit for its sources and storage operators. Some of the states within this region have primacy (North Dakota and Wyoming) for issuing Class VI injection permits. [27] Primacy, approved by the EPA, provides the states the ability to enforce Underground Injection Control (UIC) Class VI permits designed to protect underground sources of drinking water. The storage operator within this region can also benefit from storage liability transfers post-injection provided by some states (e.g., North Dakota [48]), which could provide cost benefits to a source. This area also has local storage reservoirs for a source to transport its captured CO_2, with some providing a high-quality option.

Like the Northwest Impact Area, the Gulf Impact Area also provides benefits to the sources within this region since there are several high-quality storage reservoir options. Also, some of these states are obtaining primacy for CO_2 storage operations and/or have the ability to provide liability transfer (e.g., Louisiana [27] [49]). Exhibit 3-6 shows the overall CCS network within the Central United States study area highlighting the regional impact areas as well as the modeled CCS networks within each regional impact area.

Exhibit 3-6. Maps showing study area highlighting regional impact areas and modeled CCS network scenarios within regional impact areas in the Central United States



Note: Top left map shows the modeled CCS network scenarios for the whole Central United States study area. Colored circles highlight the three regional impact areas and those CO_2 sources, pipeline connections, and storage reservoirs within that particular CCS network. A pipeline network representing both the dedicated and trunkline networks (blue line) was used to connect the CO_2 source types and storage reservoirs since the dedicated pipeline and trunkline networks follow the same ROWs. However, it is important to note that hubs and gathering and distribution pipelines are also in a trunkline network but not represented on this map. The more detailed CCS network scenarios for each regional impact area are shown in the other maps: Central Impact Area (bottom left), Northwest Impact Area (top right), and Gulf Impact Area (bottom right). For these maps, the dedicated pipeline network (left) and the trunkline network (right) are shown for connecting the CO_2 sources (colored circles) to the storage reservoirs. Storage reservoirs are represented as reservoir centroids (blue squares), which are potential storage reservoir sites, and respective storage formations are shown as colored outlines. For simplicity, Central = Central Impact Area, NW = Northwest Impact Area, and Gulf = Gulf Impact Area.

4 ANALYSIS RESULTS AND DISCUSSION

An overview on the findings of this analysis for each regional impact area along with explanatory text is discussed in this section. For simplicity, results for only the dome storage structural setting and largest trunkline diameter (30/36 in.) are considered. Additionally, for the dedicated pipeline network, the CO_2 from smaller sources was transported via a 4-, 6-, or 8-in. pipeline (ethanol plant, natural gas processing plant, and cement plant, respectively) or, in the case of the larger source, a 12-in. pipeline (SCPC power plant). All costs refer to the unit cost ($/tonne) in 2018$. It is easier to compare the unit cost for all links of the CCS value chain since different amounts of CO_2 are transported and stored (based on capture rate). This section also includes a comparison of all sources across all three regional impact areas. Maps are the main feature within this section to illustrate the results. Other tables are also shown, where appropriate, to highlight findings. The maps show the modeled CCS network for each regional impact area for both the dedicated pipeline and trunkline networks. A pie chart is also shown on the maps, which identifies the location of the storage reservoir centroid for each storage site. Each color in the pie chart represents the cost of each link in the CCS value chain as a percentage of the total CCS cost. Each cost item of the value chain is summed to a single value representing the total cost of CCS with this value (rounded to the nearest whole number) posted at the storage reservoir next to the pie chart in each map. Colored circles represent the CO_2 sources on the maps with the CO_2 source of interest designated by a larger colored circle.

The 2018 Grant et al. study [24] discussed several factors that have an effect on the overall CCS cost and, thus, the percentage of each CCS component (i.e., capture, storage, and transport). These factors included location of CO_2 source, capture rate of CO_2 source, quality of storage reservoir, and distance between source and sink. The influence of these factors was seen in this analysis when looking at each individual component cost or the whole CCS cost. Capture costs for the ethanol and natural gas processing plants in the Central Impact Area were 5–17 percent of overall CCS costs when a dedicated pipeline for transport was used. When a trunkline network was used, the capture costs were 13–34 percent of overall CCS costs. Capture costs were the lowest cost component for these two sources, unlike for the cement and SCPC plants in the Northwest Impact Area and Gulf Impact Area where it was the highest cost component (61–84 percent of the total CCS costs when a dedicated pipeline was used and 69–85 percent when a trunkline network was used). The capture cost as a percentage of CCS costs for all sources increased as trunkline diameter increased which in turn lowered the unit cost to transport CO_2.

For the ethanol and natural gas processing plants in the Central Impact Area, storage costs were 11–33 percent of total CCS costs when a dedicated pipeline was utilized, but the storage cost percentages increased to 27–68 percent when a trunkline network was utilized. For the cement and SCPC plants in the Northwest Impact Area and Gulf Impact Area, storage cost percentages of overall CCS costs were much lower (6–16 percent when a dedicated pipeline was used and 9–19 percent when a trunkline network was used) making it the lowest-cost component for the majority of sources within these impact areas. As seen with capture cost percentages, storage costs percentages for all sources increased as trunkline diameter increased. Storage costs are not a function of CO_2 source location and remain the same for each specific rate of capture regardless of the source location or transportation network and distance.

Transport costs were the largest component of overall CCS costs for the ethanol and natural gas processing plant in the Central Impact Area (51–82 percent when a dedicated pipeline was used and 18–51 percent when a trunkline network was used). For the cement and SCPC plants in the Northwest Impact Area and Gulf Impact Area, transport costs were 1–30 percent when a dedicated pipeline was used and 2–24 percent of total CCS costs when a trunkline network was used. Thus, for some sources, transport costs provided the lowest cost component due to the benefit of a lower unit cost to transport. Transport cost percentages for all sources decreased with increasing trunkline diameter.

Other modeling results are within the appendices. Results related to CO_2 plume data and CO_2 storage costs can be found in Appendix A: CO_2 Plume Data and CO_2 Storage Costs. Diameter, distance, and booster pump data for pipeline/trunkline segments in the dedicated pipeline and trunkline networks along with associated CO_2 transport costs can be found in Appendix B: Pipeline/Trunkline Diameter, Pipeline/Trunkline Distance, Booster Pumps, and CO_2 Transport Costs. Raw data calculated for each link of the CCS value chain across all evaluated scenarios are in Appendix C: Total CCS Costs for Scenarios.

4.1 Central Impact Area

Transport costs make up the largest percentage of the overall CCS costs (66–82 percent) for the ethanol plant in Iowa, as can be seen by the green portion of the pie chart in the left map of Exhibit 4-1. The high transport costs are due to the distance the ethanol plant needs to transport its 0.12 Mt/yr of CO_2 since there are no storage reservoirs within 400 mi. Storage costs are the second largest percentage of total CCS costs in the dedicated pipeline network (13–29 percent) followed by capture costs (5–9 percent). Because the ethanol plant is a high purity source, its capture costs are low. In the trunkline network, storage costs become the largest portion of the overall CCS costs (52–68 percent) followed by transport (18–27 percent) then capture (13–21 percent). Because the trunkline network provides the capacity to transport multiple sources, it provides a lower unit cost to transport due to an increase in the mass of CO_2 transported, thus, affecting the transport cost. This lower unit cost provides such a benefit to the ethanol plant that storage reservoir quality cannot outweigh it, thus, the larger percentage of storage costs to the overall CCS cost.

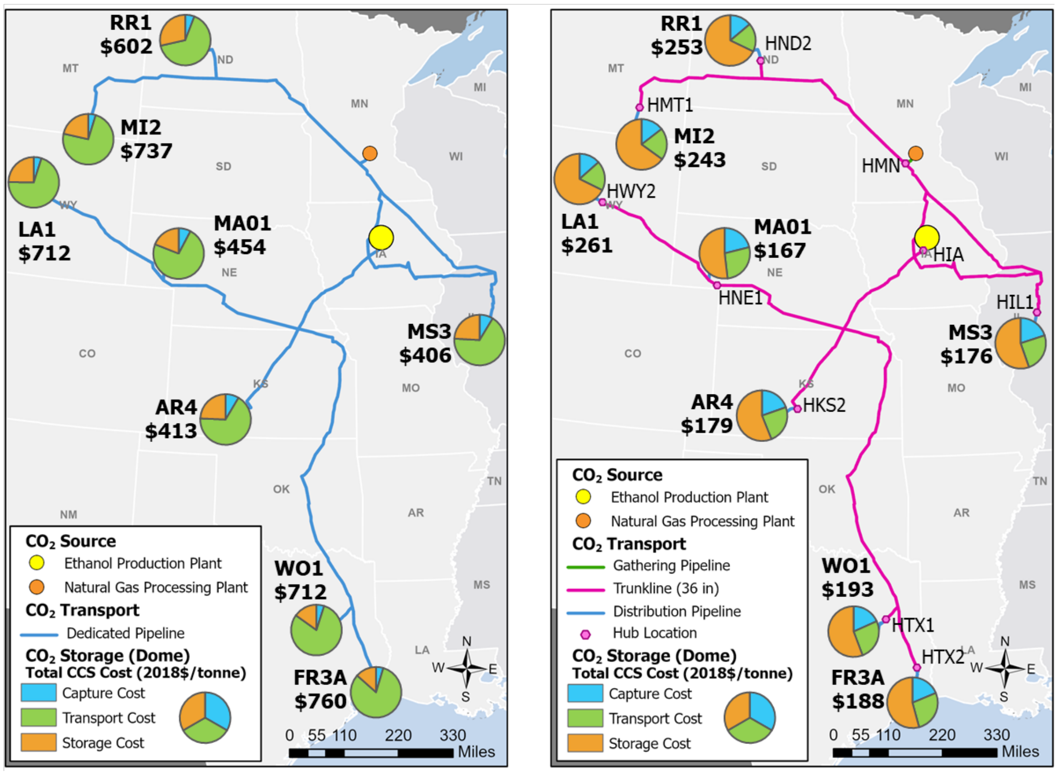
The Mt. Simon 3 storage reservoir provides the lowest CCS cost option for the ethanol plant at \$406/tonne in the dedicated pipeline network, which is due to its low transport cost because of its proximity to the source (480 mi) and low storage costs due to its fairly good storage reservoir quality. Arbuckle 4 and Maha 01 are also options at \$413/tonne and \$454/tonne, respectively, before costs start increasing by \$200-300/tonne due to the larger transport costs for the more distant storage reservoirs. More distant reservoirs become an option for the source when utilizing a trunkline network because of the lower unit cost of transport.

Maha 01 is the lowest CCS cost option in the trunkline network at \$167/tonne, \$287/tonne cheaper than in the dedicated pipeline network (Exhibit 4-1). This reduction shows an economy of scale in the transport cost. A trunkline is less sensitive to a CO_2 source's transport rate since it provides the same transport cost per its diameter and total capacity regardless of the source's size (i.e., capture rate). A source can take advantage of the lower unit transport costs of a trunkline because capital and operating expenses for a trunkline are shared by multiple sources compared to a dedicated pipeline where they are covered by a transportation fee to a single source. Total CCS costs in the dedicated pipeline network are $229–572/tonne more than overall CCS costs in the trunkline network for the ethanol plant (left map in Exhibit 4-1). There is a $355/tonne CCS cost difference from the lowest CCS cost option to the largest in the dedicated pipeline network. This cost difference is reduced to $94/tonne within the trunkline network using a 36-in trunkline (right map in Exhibit 4-1) due to the dollar per tonne reduction in transport costs across all storage reservoirs.

For storage, Maha 01 provided the lowest storage cost since its depth is 470–4,200 ft less than all the other reservoirs, benefitting from lower well drilling costs. As seen in the dedicated pipeline network, Mt. Simon 3 and Arbuckle 4 are within the top three lowest CCS cost options at $176/tonne and $179/tonne, respectively. Even though Woodbine 1 and Frio 3a are 1,004 mi and 1,099 mi, respectively, from the ethanol plant, the trunkline network allows them to be competitive with their CCS costs only $21–26/tonne more than Maha 01 (compared to $306/tonne and $355/tonne more than Mt. Simon 3, the lowest CCS cost option in the dedicated pipeline network). Woodbine 1 is actually $5/tonne more expensive than Frio 3a, due to slightly higher storage costs since Woodbine 1 is 500 ft deeper and therefore has higher drilling costs. Even with its fairly good storage reservoir quality and shorter transport distance, the difference in storage costs is just enough for the ethanol plant to consider Frio 3a over Woodbine 1.

A supplementary case study was done to demonstrate the cost impact on a large source versus a small source when local storage is not an option. This analysis was performed by modeling a SCPC power plant (capture rate 4.33 Mt/yr) at the same location as the ethanol plant for both the dedicated pipeline and trunkline networks. The results of this case study can be found in Appendix D: Economies of Scale – A Case Study.

Exhibit 4-1. Maps showing total CCS cost and percent of each component for ethanol plant in Central Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



Just like the ethanol plant, transport costs provide the largest portion of overall CCS costs (51–80 percent) for the natural gas processing plant in Minnesota when using a dedicated pipeline network (Exhibit 4-3). There are no reservoirs within 400 mi for the natural gas processing plant to store its 0.55 Mt/yr of CO_2, so distance plays a factor in transport costs. Storage costs are the second largest cost component of total CCS costs (11–33 percent) followed again by capture costs (9–17 percent). The natural gas processing plant is also a high-purity source, thus, the low capture cost. Just like the trend seen for the ethanol plant, storage costs are the largest portion of overall CCS costs (36–55 percent) followed by transport costs (18–35 percent) and then capture costs (24–34 percent) when using a trunkline network.

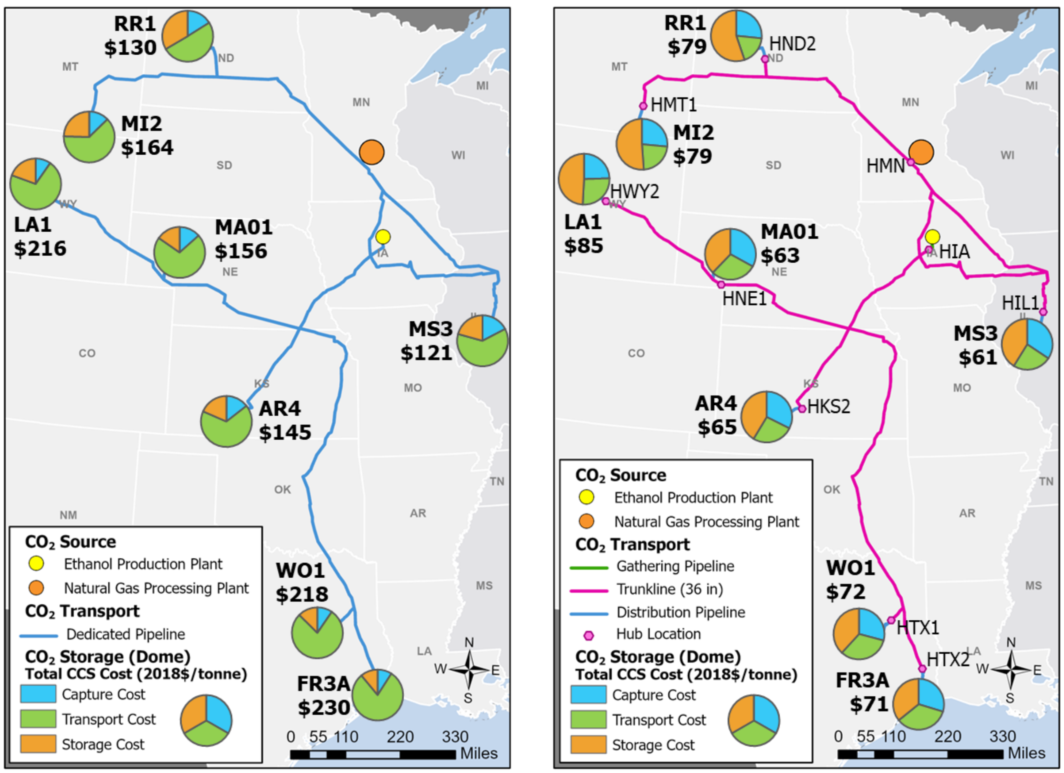
Exhibit 4-2. CCS component as a percentage of total CCS costs by storage reservoir for the Central Impact Area (dome)

Central – Dome	0.12 Mt/yr (ET)						0.55 Mt/yr (NGPP)					
	Dedicated			Trunkline - 36 in.			Dedicated			Trunkline - 36 in.		
Storage Reservoir	% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost		
ID	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage
MI2	5%	74%	21%	15%	20%	65%	13%	63%	25%	26%	22%	51%
LA1	5%	70%	25%	13%	19%	68%	10%	71%	19%	24%	26%	49%
RR1	6%	66%	29%	14%	18%	68%	16%	51%	33%	27%	18%	55%
MA01	8%	73%	19%	21%	27%	52%	13%	71%	15%	33%	29%	38%
AR4	9%	67%	24%	20%	24%	56%	14%	67%	18%	32%	26%	41%
WO1	5%	80%	15%	18%	26%	56%	10%	78%	13%	29%	33%	38%
FR3A	5%	82%	13%	19%	27%	54%	9%	80%	11%	30%	35%	36%
MS3	9%	67%	24%	20%	25%	55%	17%	62%	21%	34%	24%	41%

However, the ranges of these cost components are closer than those for the ethanol plant since costs for each CCS cost component for the natural gas processing plant are similar, none exceed \$50/tonne. For example, if the natural gas processing plant wanted to store its CO_2 in the Maha 01 storage reservoir, capture cost is \$21/tonne, storage is \$24/tonne, and transport is 19/tonne; these costs are within \$2/tonne to \$5/tonne of each other for the trunkline network. However, in the dedicated pipeline network, these same costs are \$21/tonne, 24/tonne, and \$111/tonne, respectively, making them within \$3/tonne to \$87/tonne of each other. When comparing with the ethanol plant storing its CO_2 in Maha 01 in the dedicated pipeline network, capture cost is \$35/tonne, storage is \$86/tonne and transport is \$333/tonne; these costs are within \$51/tonne to \$297/tonne of each other. In the trunkline network, these same costs are \$35/tonne, \$86/tonne, and \$45/tonne; respectively, making them within \$10/tonne to \$51/tonne of each other.

The difference in total CCS costs between the dedicated pipeline network and trunkline network for the natural gas processing plant are \$51–159/tonne (Exhibit 4-3). Even though the cost savings between both transportation networks are much smaller compared to the ethanol plant, this source still benefits from a trunkline. There is a \$109/tonne difference between the lowest and highest CCS cost option for the natural gas processing plant within the dedicated pipeline network. With a 36-in trunkline, this cost difference is reduced to \$25/tonne. Just like the ethanol plant, the cost difference is due to the reduction in transport costs. The smaller cost difference in the trunkline network shows the benefits of a trunkline on small sources (i.e., low capture rates). The Mt. Simon 3 storage reservoir is the lowest CCS cost option for the natural gas processing plant in the dedicated pipeline network at \$121/tonne. Red River 1 is 66 mi closer than Mt. Simon 3 but Mt. Simon 3 has better storage reservoir quality; therefore, its low storage cost contributes to its slight advantage over Red River 1. Four other storage reservoirs provide CCS costs less than \$200/tonne before costs start increasing by almost \$100/tonne due to the longer transport distances increasing transport costs. In the trunkline network, more distant storage reservoirs could be considered, but Mt. Simon 3 still provides the lowest CCS cost option at \$61/tonne, which is \$60/tonne cheaper than the dedicated pipeline network. Unlike the dedicated pipeline network, Maha 01 is within the top three lowest CCS cost options at \$63/tonne. With Maha 01's low storage cost and a \$93/tonne reduction in transport costs, it is able to surpass Red River 1 even though it is further away from the natural gas processing plant. As mentioned with the ethanol plant, even though Woodbine 1 and Frio 3a are 1,196 mi and 1,292 mi (Exhibit C-5), respectively, from the natural gas processing plant, they can also be considered as a possible storage option with the trunkline network. Their CCS costs are only $6–7/tonne cheaper than Arbuckle 4, which is the third best storage option. Again, Woodbine 1's shorter transport distance cannot outweigh its slightly higher storage costs, thus, causing it to be more expensive than Frio 3a.

Exhibit 4-3. Maps showing total CCS cost and percent of each component for natural gas processing plant in Central Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



4.2 NORTHWEST IMPACT AREA

The Northwest Impact Area evaluates a cement plant and two SCPC power plants in close proximity to storage reservoirs, making it the smallest and most compact impact area out of the three areas analyzed. The closest storage reservoir is 30 mi and the furthest is 636 mi. In all 12 scenarios in the dedicated pipeline network, capture costs make up the largest portion of the overall CCS costs, as illustrated by the blue portion of the pie charts in Exhibit 4-5, Exhibit 4-6, and Exhibit 4-7. On average, capture costs make up about 63 percent of the overall CCS costs for the cement plant located in South Dakota (Exhibit 4-5) and 77 percent and 74 percent for the SCPC plants located in Wyoming (Exhibit 4-6) and North Dakota (Exhibit 4-7), respectively. Even though SCPC power plants and cement plants are both considered low purity sources, capture costs are significantly lower for SCPC power plants by $41/tonne. This cost variability is due to the processing (separation, purification, and compression) and energy consumption required to make the CO_2 stream from a cement plant pipeline compliant compared to the CO_2 stream from a SCPC power plant, as discussed in Section 2.2.1.

Transport costs made up the second largest percentage of CCS costs for the cement plant and the SCPC power plant in North Dakota, but the third largest percentage for the SCPC power plant in Wyoming. On average, transport costs are responsible for 23 percent of CCS costs for the cement plant, and 11 percent (SCPC in Wyoming) and 14 percent (SCPC in North Dakota) for the power plants. In general, if the dedicated pipeline length is over 300 mi, transport costs tend to be higher than storage costs. However, for dedicated pipelines that are right around 300 mi (approximately +/- 30 mi), costs can go either way. The deciding factor is the change in elevation. If the change in elevation is positive (sink is higher than source), then transportation costs are higher than storage costs, but if the change in elevation is negative (source is higher than sink), then storage costs tend to be higher than transportation costs. Lastly, storage costs make up 14 percent of CCS costs for the cement plant, and 12 percent of costs in both the SCPC power plants.

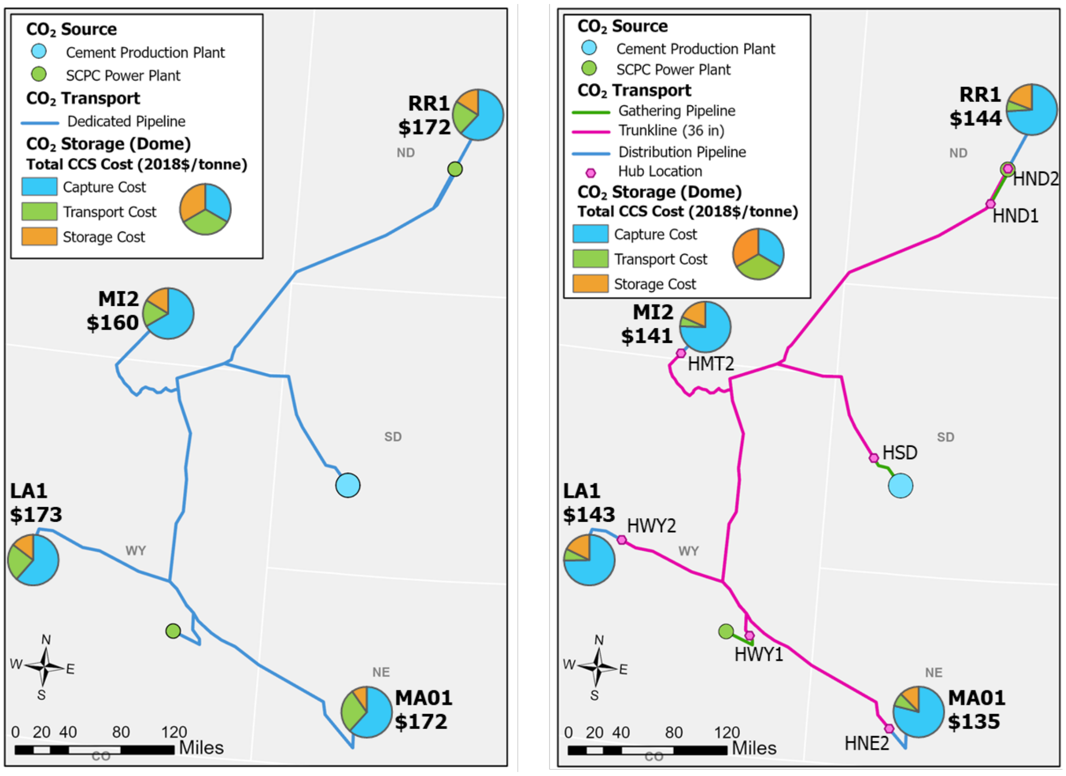
Exhibit 4-4. CCS component as a percentage of total CCS costs by storage reservoir for the Northwest Impact Area (dome)

NW – Dome	0.97 Mt/yr (CE_SD)					
	Dedicated			Trunkline - 36 in.		
Storage Reservoir	% of Total CCS Cost			% of Total CCS Cost		
ID	Capture	Transport	Storage	Capture	Transport	Storage
MI2	67%	17%	16%	75%	6%	18%
LA1	61%	24%	15%	75%	8%	18%
RR1	62%	22%	16%	74%	7%	19%
MA01	62%	29%	10%	79%	9%	12%

NW – Dome	4.33 Mt/yr (SCPC_WY)						4.33 Mt/yr (SCPC_ND)					
	Dedicated			Trunkline - 36 in.			Dedicated			Trunkline - 36/30 in.		
Storage Reservoir	% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost		
ID	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage
MI2	75%	11%	13%	80%	6%	14%	73%	14%	13%	79%	7%	14%
LA1	83%	7%	10%	85%	4%	11%	72%	19%	9%	80%	10%	10%
RR1	70%	18%	13%	78%	8%	14%	84%	1%	15%	83%	2%	15%
MA01	81%	8%	11%	84%	4%	12%	69%	22%	10%	78%	11%	11%

In all 12 scenarios for the trunkline network, capture costs are the largest percentage of the overall CCS costs, followed by storage costs and then transport costs. Capture costs are 76 percent of overall CCS costs for the cement plant in South Dakota and 80 percent for both the SCPC power plants. Storage costs are 17 percent for the cement plant, 13 percent for the SCPC plant in Wyoming, and 12 percent for the SCPC plant in North Dakota. Lastly, transport costs are responsible for 8 percent of total CCS costs for the SCPC plant in North Dakota and 7 percent for both the cement plant and the SCPC plant in Wyoming. The majority of cases (11 out of the 12) benefit cost wise from a trunkline network over a dedicated pipeline network.

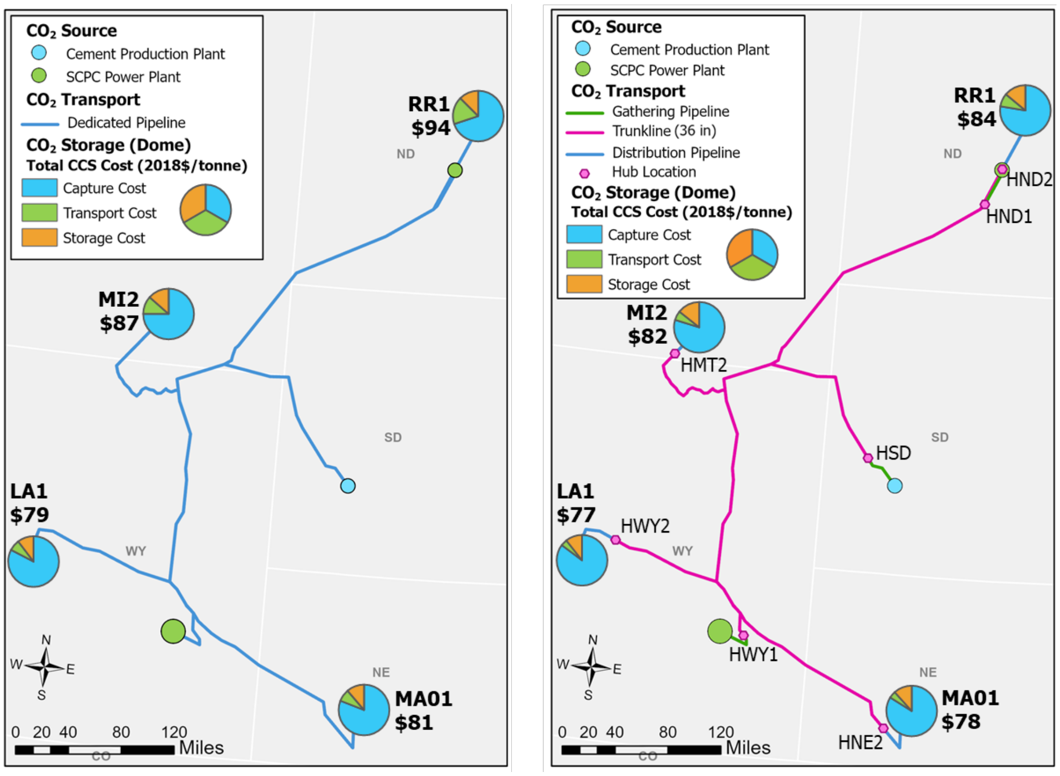
Exhibit 4-5. Maps showing total CCS cost and percent of each component for cement plant – South Dakota in Northwest Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



The only scenario that does not benefit from a trunkline is for the SCPC power plant in North Dakota and is only 30 mi from Red River 1, also located in North Dakota (Exhibit 4-5). Since gathering and distribution pipelines are each 30 mi for this analysis, a trunkline network is not possible for this scenario given the total distance from source to sink is around 30 mi. However, for consistency and to compare costs, a trunkline network (30-mi gathering pipeline, a trunkline, and 30-mi distribution pipeline) was designed for this scenario with a total pipeline length of 99 mi. Overall, the dedicated pipeline network cost $1/tonne less under this scenario.

Additionally, smaller sources (e.g., cement plants, ethanol plants) benefit more from a trunkline network compared to larger sources (e.g., SCPC power plants). The cement plant saves on average $29/tonne using a trunkline network versus a dedicated pipeline network, whereas SCPC power plants save an average of $7/tonne. Furthermore, the longer the pipeline required to transport CO_2 from source to sink, the larger the cost savings per tonne of CO_2 transported, regardless of the size of the source. For example, the pipeline from the SCPC power plant in Wyoming to Lance 1 is 191 mi and saves $2.42/tonne in a trunkline network compared to a dedicated pipeline network. The same source saves $9.33/tonne when transporting CO_2 541 mi to Red River 1. The pipeline from the cement plant to Minnelusa 2 is 302 mi and saves $19/tonne with the trunkline network. When the cement plant travels 545 mi to Maha 01 the savings is $38/tonne. The SCPC plant has a larger amount of CO_2 to transport than the cement plant, yet, in both cases, the longer the distance from the source to the storage reservoir, the larger the cost savings per tonne with the trunkline network.

Exhibit 4-6. Maps showing total CCS cost and percent of each component for SCPC power plant – Wyoming in Northwest Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)

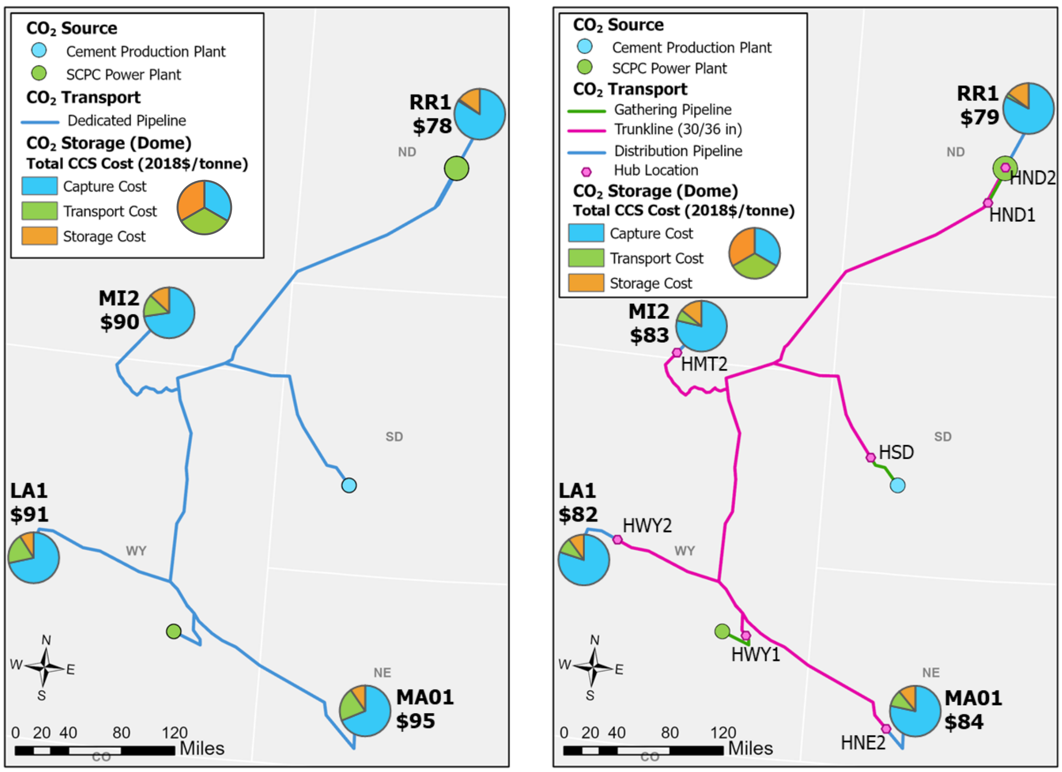


Since the Northwest Impact Area has a small range in transport distances and storage costs are similar among the storage reservoirs, there is a small variance in total CCS costs for each individual source and network. For the cement plant, the cheapest option is Minnelusa 2 for the dedicated pipeline network at $160/tonne and Maha 01 for the trunkline network at $135/tonne (Exhibit 4-5). The reason Minnelusa 2 is not the cheapest option for the trunkline network as well is a combination of transport costs and storage costs. Both Minnelusa 2 and Maha 01 are similar in storage reservoir quality; however, Maha 01 is a slightly cheaper storage option. As for transport costs, Maha 01 saved $38/tonne with the trunkline network, and the cost savings for Minnelusa 2 was only $19/tonne, making Maha 01 the cheapest option for the trunkline network. The total CCS cost range from the cheapest option (Maha 01) to the most expensive option (Lance 1) in the dedicated pipeline network was $13/tonne for the cement plant. For the trunkline network, this cost range was $9/tonne.

For the SCPC plant located in Wyoming, the cheapest option is Lance 1 for both transportation network types. For both the dedicated pipeline and trunkline networks, Lance 1 has the cheapest transport costs ($6/tonne and $3/tonne, respectively) and storage costs ($8/tonne). The total CCS cost range from the highest to lowest cost options in the dedicated pipeline network and trunkline network for the SCPC plant in Wyoming were $15/tonne and $7/tonne, respectively (Exhibit 4-6).

Similar to the SCPC plant in Wyoming, the cheapest option, Red River 1, for the SCPC plant in North Dakota remains the same across both transportation networks (Exhibit 4-7). Red River 1 has the highest storage costs ($4/tonne more than the cheapest) of the four options; however, transport costs are the cheapest. The cheapest transport costs are $1/tonne for the dedicated pipeline network and $2/tonne for the trunkline network, which are $20/tonne and $8/tonne cheaper than the most expensive transport costs in each network, respectively. The extremely low transport cost for the SCPC power plant in North Dakota to go to Red River 1 is due to the close proximity of the source and sink, which is why it is the lowest total CCS cost option. The total CCS cost range from the highest to lowest cost options in the dedicated pipeline network and trunkline network were $17/tonne and $5/tonne, respectively.

Exhibit 4-7. Maps showing total CCS cost and percent of each component for SCPC power plant – North Dakota in Northwest Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



4.3 Gulf Impact Area

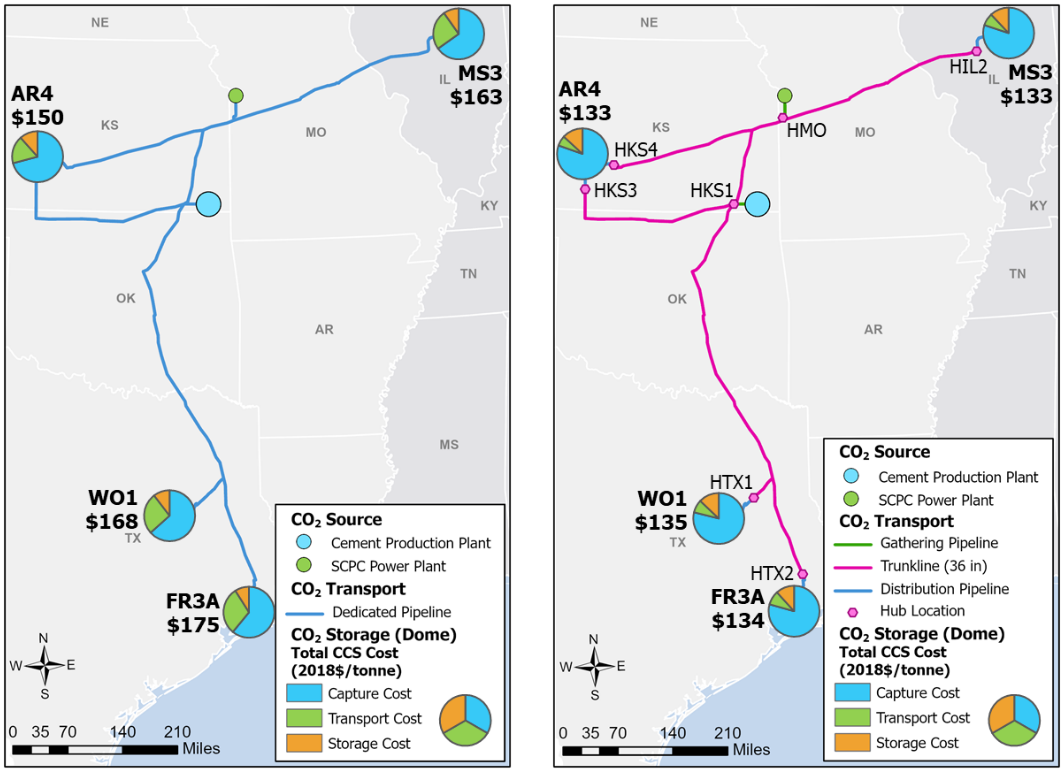
When using a dedicated pipeline or trunkline network, capture costs make up the largest portion of the overall CCS costs (61–71 percent) for the cement plant in Kansas, as can be seen by the blue portion of the pie chart in Exhibit 4-9. The high cost of capture is due to the cement plant being a low purity source. Transport costs are the second largest percentage of total CCS costs in the dedicated pipeline network (18–30 percent) followed by storage costs (9–12 percent), but that role is reversed in the trunkline network (12–13 percent for storage costs and 6–9 percent for transport costs). Since the trunkline network provides the capacity to transport multiple sources, it provides a lower unit cost to transport due to an increase in the mass of CO_2 transported, thus, affecting the transport cost. Just like the cement plant, capture costs provide the largest percentage of overall CCS costs (60–85 percent) for the SCPC plant when using a dedicated pipeline or trunkline network since it also is a low purity source (blue portion of pie chart in Exhibit 4-10). Transport costs are the second largest cost component of total CCS costs in the dedicated pipeline network (11–24 percent) followed by storage costs (6–10 percent). Unlike the trunkline network for the cement plant, transport costs are also the second largest at 6–12 percent of overall CCS costs for the SCPC plant in the trunkline network, while storage costs are cheapest at 7–11 percent. This trend shows that a trunkline network benefits a small source (i.e., one with a small capture rate) more than a large source (i.e., one with a large capture rate).

Exhibit 4-8. CCS component as a percentage of total CCS costs by storage reservoir for the Gulf Impact Area (dome)

Gulf – Dome	0.97 Mt/yr (CE_KS)						4.33 Mt/yr (SCPC_MO)					
	Dedicated			Trunkline - 36 in.			Dedicated			Trunkline - 36 in.		
Storage Reservoir	% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost			% of Total CCS Cost		
ID	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage	Capture	Transport	Storage
AR4	71%	18%	12%	80%	6%	13%	75%	11%	10%	84%	6%	11%
WO1	63%	26%	10%	79%	8%	13%	83%	22%	8%	80%	11%	9%
FR3A	61%	30%	9%	79%	9%	12%	70%	24%	6%	81%	12%	7%
MS3	65%	25%	10%	80%	8%	12%	81%	13%	8%	85%	6%	9%

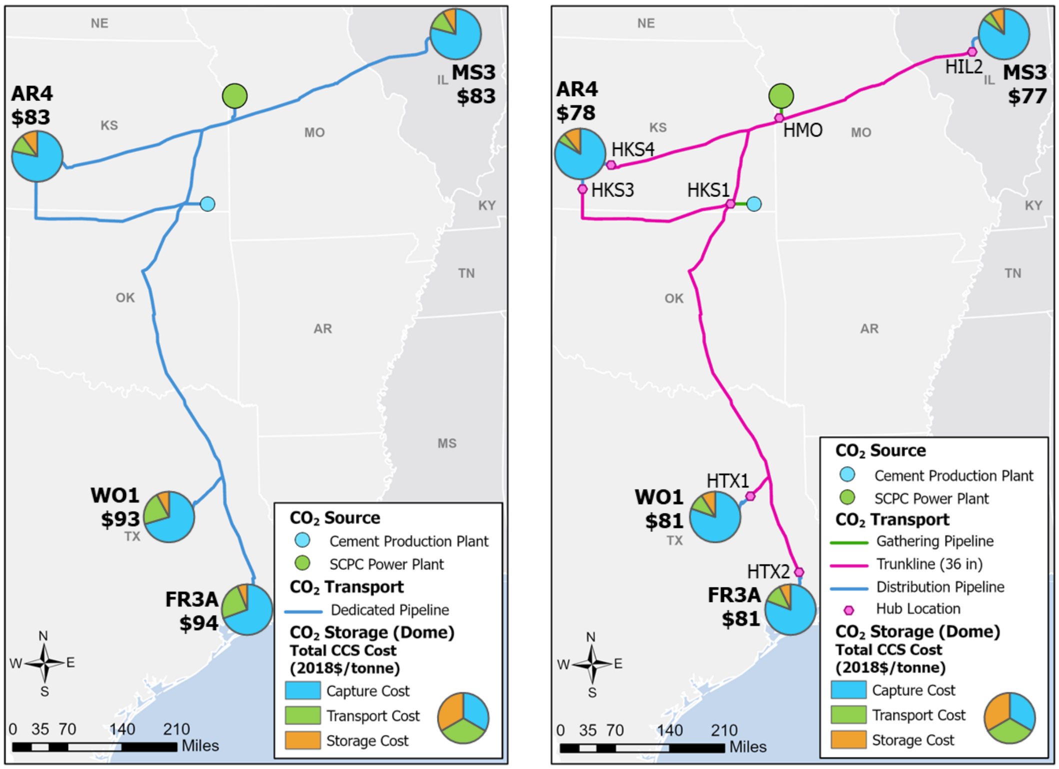
Total CCS costs in the dedicated pipeline network are \$17–\$41/tonne more than overall CCS costs in the trunkline network for the cement plant (left map in Exhibit 4-9), which has a capture rate of 0.97 Mt/yr. When comparing CCS costs within the dedicated pipeline network, there is a \$25/tonne difference from the lowest CCS cost option to the highest cost option. This difference is reduced to \$2/tonne within the trunkline network using a 36-in trunkline allowing farther reservoirs to be more attractive and showing the benefits of a trunkline network (right map in Exhibit 4-9). The Arbuckle 4 storage reservoir provides the lowest CCS cost option for the cement plant at \$150/tonne in the dedicated pipeline network, which is contributed to its short transport distance (291 mi). Mt. Simon 3 provides the second lowest cost. However, in the trunkline network, both Arbuckle 4 and Mt. Simon 3 storage reservoirs provide the lowest CCS cost option at \$133/tonne–\$17/tonne and \$30/tonne cheaper, respectively, than in the dedicated pipeline network. Mt. Simon 3 becomes just as attractive as Arbuckle 4 in the trunkline network due to the \$30/tonne reduction in transport costs. Even though Frio 3a provides the highest-quality storage option followed by Woodbine 1, it is not enough to compensate for the longer transport distance in the dedicated pipeline network. In the trunkline network, these storage reservoirs become more attractive with Frio 3a actually providing a cheaper CCS cost than the Woodbine 1 storage reservoir. Woodbine 1 is 500 ft deeper than Frio 3a impacting drilling costs and causing a slightly higher storage cost. Even with its fairly good storage reservoir quality and shorter transport distance, the difference in storage costs is just enough for the cement plant to consider Frio 3a over Woodbine1. However, the cement plant may choose to travel the 484 mi to Woodbine 1 or 584 mi to Frio 3a since their costs are only \$2/tonne and \$1/tonne, respectively, more expensive than Arbuckle 4 and Mt. Simon 3 storage reservoirs.

Exhibit 4-9. Maps showing total CCS cost and percent of each component for cement plant – Kansas in Gulf Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



Unlike for the cement plant in the dedicated pipeline network, total CCS costs are only $4–11/tonne more than overall CCS costs in the trunkline network for the SCPC plant (left map in Exhibit 4-10). This decrease in costs between the two transportation networks is due to the larger mass of CO_2 captured by the SCPC plant (4.33 Mt/yr versus 0.97 Mt/yr for the cement plant). There is a $11/tonne difference from the lowest CCS cost options to the highest for the SCPC plant when comparing CCS costs within the dedicated pipeline network. The trunkline network, which utilizes a 36-in. trunkline, only has a $4/tonne difference. Again, this small CCS cost difference between a dedicated pipeline and trunkline network shows that a source with a lower capture rate benefits from a trunkline more than one with a larger capture rate, which is why the SCPC plant does not see as much of a cost break as the cement plant in the trunkline network. The Arbuckle 4 storage reservoir is the lowest CCS cost option for the cement plant, but for the SCPC plant, Arbuckle 4 as well as Mt. Simon 3 provide the lowest CCS cost options in the dedicated pipeline network at $83/tonne. Arbuckle 4's short transport distance (292 mi) and Mt. Simon 3's better storage reservoir quality allows both storage reservoirs to be cost competitive. In the trunkline network, Mt. Simon 3 provides the lowest CCS cost option for the SCPC plant at $77/tonne, $6/tonne cheaper than the dedicated pipeline network. The transport cost difference between Mt. Simon 3 and Arbuckle 4 is less than $1/tonne in the trunkline network even though Mt. Simon 3 is 37 more miles away from the SCPC plant; however, the storage costs reflect the better storage reservoir quality of Mt. Simon 3 (around $2/tonne less than Arbuckle 4), which gives it a slight advantage. Arbuckle 4 is also 1,095 ft deeper than Mt. Simon 3, which affects drilling costs and, thus, storage costs. Frio 3a and Woodbine 1 are still unattractive storage options for the SCPC plant in the dedicated pipeline network due to their transport distance; however, in the trunkline network, they both provide the same CCS cost, which is only $4/tonne more than the cheapest option. Therefore, the SCPC plant could choose to transport its captured CO_2 the 632 mi to Woodbine 1 or 728 mi to Frio 3a for storage in a better-quality storage reservoir.

Exhibit 4-10. Maps showing total CCS cost and percent of each component for SCPC power plant – Missouri in Gulf Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



4.4 CCS Cost Comparison Across All Regional Impact Areas

There are three regional impact areas for this CCS analysis using sources typical for each area. The Central Impact Area is the largest with eight storage reservoirs and three sources. These storage reservoirs were divided to create the Northwest Impact Area and the Gulf Impact Area, which are smaller in areal extent (Exhibit 3-6) allowing for a more localized CCS cost analysis. As seen in the sections above, there are many factors that drive CCS costs such as the mass of CO_2 captured, transport distance to a suitable storage reservoir, and quality of the storage reservoir. All of these factors play an important role when comparing sources across all regional impact areas.

Within the Central Impact Area, the ethanol plant has the highest CCS costs (Exhibit 4-11), ranging from $406 to $760/tonne. Even though an ethanol plant has the second lowest capture cost of the sources modeled, it has the lowest emission rate of 0.12 Mt/yr of CO_2. CO_2 transportation costs for a dedicated pipeline for this plant exceed the overall CCS cost of all other source-sink combinations modeled. However, smaller sources have a large cost advantage with respect to a trunkline network, as illustrated in Exhibit 4-12. Use of a trunkline for transportation significantly reduces these costs for an ethanol plant yet CCS costs here are still greater than that for the other systems modeled (Exhibit 4-12). With the lower unit cost of the trunkline, overall CCS costs for the ethanol plant were reduced by 56–75 percent ($229–572/tonne, Exhibit 4-12)). The natural gas processing plant also benefited from the trunkline network with costs being reduced by 40–69 percent ($51–159/tonne, Exhibit 4-3). The cost of capture for the natural gas processing plant is low enough to give it a low cost advantage over sources with larger capture rates like cement and SCPC plants. Depending on selection of a storage reservoir for the natural gas processing plant, CCS costs with a dedicated pipeline can be lower than CCS costs for a cement plant (Exhibit 4-11). With use of a trunkline network, CCS costs for a natural gas processing plant are lower than all cement plant source-sink combinations and lower than most SCPC plant combinations depending on storage reservoir for the natural gas processing plant (Exhibit 4-12).

Looking at the Northwest and Gulf Impact Areas, overall CCS costs are comparable across both areas for the two cement plants and the three SCPC plants. The SCPC plants have a high capture cost due to the large mass of CO_2 captured from these sources. This large mass of captured CO_2 provides an economy of scale in transport and storage resulting in lower CCS costs, with a range of $78–95/tonne (Exhibit 4-11) for any SCPC plant. The cement plant in the Gulf Impact Area has a CCS cost range of $25 per tonne with a dedicated pipeline, yet a tighter range of $2 per tonne with a trunkline system. These findings are mainly due to the lower emissions of CO_2 from the cement plant providing fewer units of CO_2 across which to spread CCS costs. The Gulf Impact Area has the three lowest cost storage reservoirs for the SCPC plants; Frio 3A, Mt. Simon 3 and Woodbine 1. The Frio 3A and Mt. Simon 3 are also the two lowest cost storage reservoirs for the cement plants even with a higher unit cost for storage due to the small CO_2 capture rate. . The three highest cost storage reservoirs for both sources are located in the Northwest Impact Area: Red River 1, Minnelusa 2, and Lance 1 for the cement plant, and Maha 01 in place of Lance 1 for the SCPC plant.

Exhibit 4-11. Bar chart showing total CCS cost and break-down of each cost component for all sources across regional impact areas by capture rate for the dedicated pipeline network (dome)

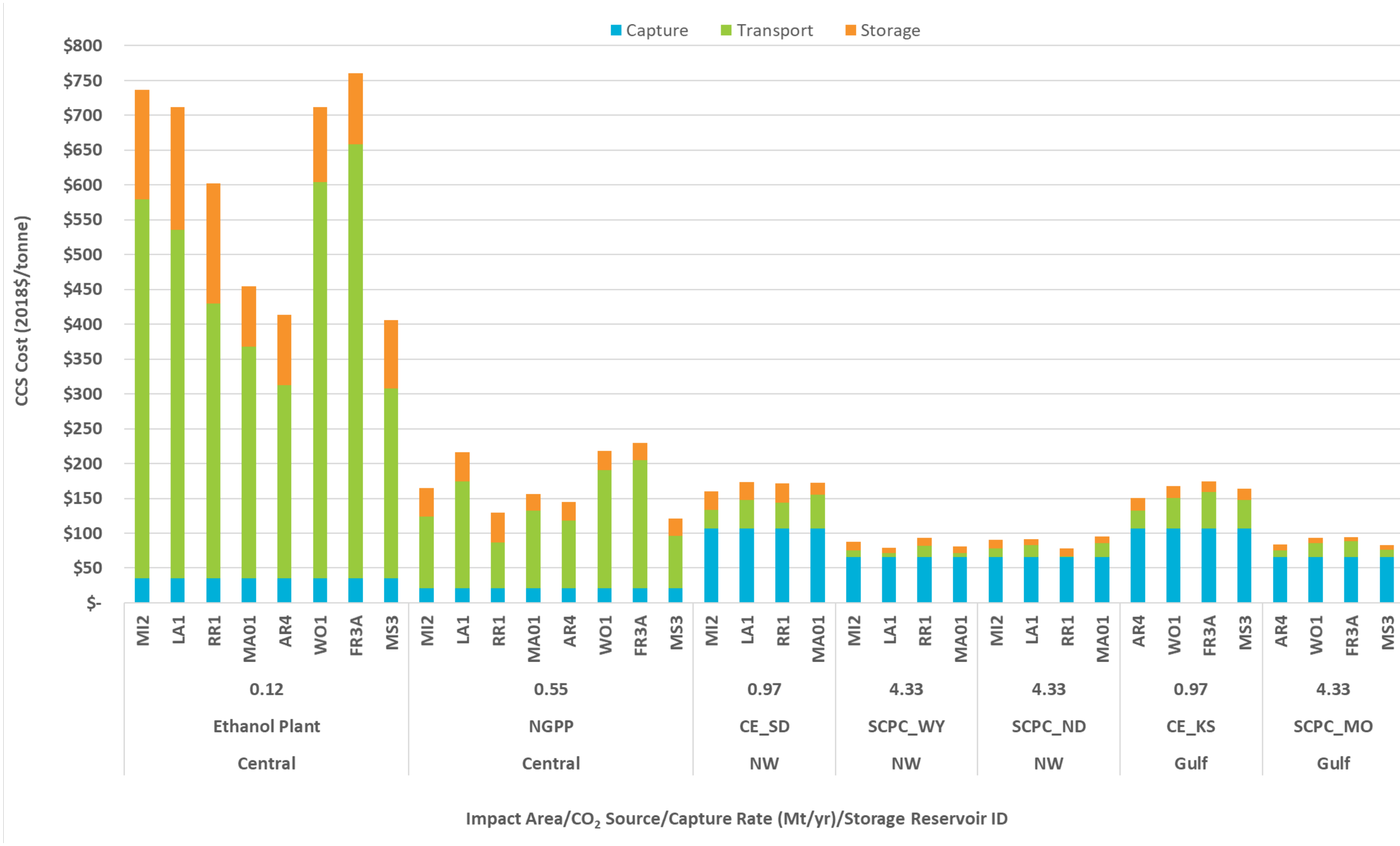
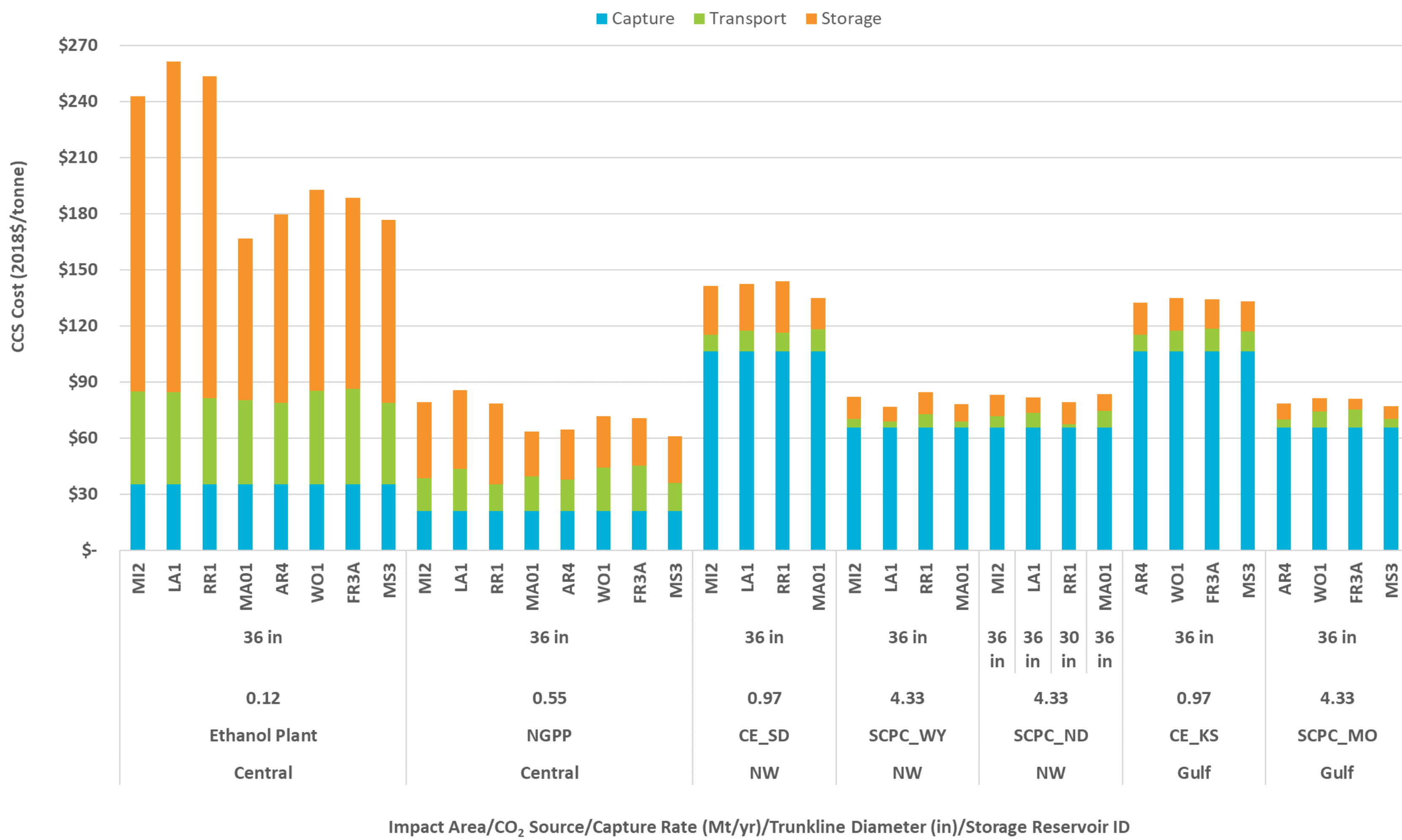


Exhibit 4-12. Bar chart showing total CCS cost and break-down of each cost component for all sources across regional impact areas by capture rate for the trunkline network (dome)



5 CONCLUSION

This analysis evaluated CCS cost options through integrated CCS networks for source types and geologic storage reservoirs specific to the Central United States. The Central United States was divided into three regional impact areas to explore the benefits and challenges a CO_2 source encounters, depending on its location within this area. A goal of this analysis was to assess options a source faces in selecting suitable storage for its captured CO_2, particularly storage and transport options since its capture options are fixed (i.e., a source cannot change its location or amount of CO_2 produced, which is linked to its capture cost). Findings demonstrated the importance in considering the geographical and geological impact a region has on costs.

Four regionally specific source types were modeled at seven regionally significant locations in the Central United States with an option to store their captured CO_2 in one of eight geologic storage reservoirs using one of two transportation networks that followed existing natural gas pipeline ROWs, thus, potentially representing more realistic CCS networks. Scenarios reflected a range of storage reservoir qualities and transportation distances. Each component of the CCS value chain and relevant cost drivers associated with each were considered to calculate the total CCS costs (i.e., summation of capture, storage, and transport costs) from a CO_2 source's perspective. Overall, results indicated that each CCS cost component is significantly affected by a source's location and sometimes a trunkline network does not provide the best option (i.e., when the transport distance is less than 30 mi). These findings also supported the factors highlighted in the 2018 Grant et al. study [24] that have the biggest influence on costs such as transportation distance and volume of CO_2. Key outcomes from the analysis results that support these findings (limited to dome structure storage setting and largest trunkline diameter) include the following:

- **Source location as well as source type play a role in costs of CCS components and, thus, overall CCS costs:** The ethanol plant and natural gas processing plant within the Central Impact Area have small capture rates, which already provide a disadvantage to storage and dedicated transport costs. With the absence of local storage reservoir options within 400 mi only increases dedicated transport costs, making it the largest cost component of total CCS costs. These two sources provide the lowest cost of capture out of the four source types modeled but it is not enough to overcome the large storage and dedicated transport costs. Sources with larger capture rates are modeled in both the Northwest and Gulf Impact Areas. Because both of these regional impact areas provide local storage reservoirs with some of the best storage reservoir quality, CCS costs are affected more by the high capture costs of both sources. Dedicated transport costs are also lower due to the shorter distances between source and sink and the higher mass of CO_2 transported lowering unit costs. When a trunkline network is utilized, a shift occurs in the portion that each cost component plays on total CCS costs (Exhibit 4-2, Exhibit 4-4, and Exhibit 4-8). Trunkline transport costs for these two sources modeled in the Central Impact Area are significantly reduced from dedicated pipeline costs by \$51–572/tonne. With trunkline transport, storage costs become the largest cost component of overall CCS costs. Even though the cost savings are seen more with the ethanol plant, the natural gas processing plant still benefits from the trunkline. The lower unit cost of transport provides such a benefit to the sources that storage reservoir quality cannot outweigh it. The larger capture rates of the sources within the Northwest Impact Area and Gulf Impact Area already provide a benefit, the trunkline simply adds savings to the transport costs. Capture costs were still the largest cost component.

Additionally, a case study was performed by modeling a SCPC power plant (capture rate 4.33 Mt/yr) in the same location as the ethanol plant for both the dedicated pipeline and trunkline networks to see the impacts on a larger source located further away from storage reservoirs. The results of this case study can be found in Appendix D: Economies of Scale – A Case Study.

- **Trunkline network reduces costs for sources but is not always best option:** Overall, the use of a trunkline network reduced transport costs for all CO_2 sources to provide lower overall CCS costs with the exception of the SCPC plant in North Dakota within the Northwest Impact Area transporting to Red River 1, which is also in North Dakota. Since gathering and distribution pipelines are each 30 mi a trunkline network is not possible for this scenario given the total distance from source to sink is around 30 mi. A 99-mi trunkline network was designed for this scenario for consistency purposes. It is $1/tonne cheaper for the SCPC plant in North Dakota to transport its CO_2 via a dedicated pipeline network when storing in Red River 1. Smaller sources benefit more from a trunkline network. Transport costs for the ethanol plant is the most affected by the trunkline pipeline followed by the natural gas processing plant. Even though the cement plant is also considered a small source; it does not see as much of a benefit from the trunkline due to shorter transport distances modeled in this study for that source type. For longer transport distances, similar to that of the ethanol plant, it is estimated a cement plant could expect a 30 percent CCS cost reduction with a trunkline network compared to a dedicated pipeline network. The SCPC plants are not affected by a trunkline due to their percentage of the trunkline volume compared to a smaller source and, thus, not being able to reap the benefits of the lower unit cost of transport. For example, a SCPC plant would occupy 10 percent of the volume in a trunkline with a capacity of 40 Mt/yr, while an ethanol plant would only take up 0.3 percent. Unlike the dedicated pipeline network where SCPC plants have the lowest CCS costs across all source types, the natural gas processing plant provides the lowest CCS in the trunkline network, except when storing CO_2 in Lance 1 where the SCPC plant in Wyoming provides the lowest cost for that storage reservoir. The cost of capture for the natural gas processing plant is low enough to give it the cost advantage over the other SCPC plants in the trunkline system.
- **Distant reservoirs become cost competitive (more so in trunkline network) depending on source type**: Throughout each regional impact area, distant reservoirs become more cost competitive depending on the source. For the smaller sources, more distant reservoirs become more cost competitive when using a trunkline network. For the ethanol plant in the Central Impact Area, Maha 01 (the third closet storage reservoir) is the lowest CCS cost option. Even though Woodbine 1 and Frio 3a are 1,004 mi and 1,099 mi (Exhibit C-7) from the source, respectively, the trunkline network allows them to be

competitive with their CCS costs, and is only $22–25/tonne more than Maha 01 (compared to $306–355/tonne more than the lowest CCS cost option in the dedicated pipeline network (Exhibit 4-1), the Mt. Simon 3). Frio 3a is actually $4/tonne cheaper than Woodbine 1 in the trunkline system even though its further away from the source; its high storage reservoir quality provides a storage cost advantage over Woodbine 1. For the natural gas processing plant, the Mt. Simon 3 (second closet storage reservoir to the source) is the lowest CCS trunkline cost option in the Central Impact Area. However, unlike the dedicated pipeline network, Maha 01 is the second lowest CCS cost options even though it is further away from the source. As with the ethanol plant, Woodbine 1 and Frio 3a become cost competitive even though they are 1,196 mi and 1,292 mi (Exhibit C-7), respectively, from the natural gas processing plant. CCS costs for these two reservoirs are only $6–7/tonne cheaper than Arbuckle 4 (Exhibit 4-3), which is the third best storage option. Again, Woodbine 1's shorter transport distance cannot overcome its slightly higher storage costs causing it to be more expensive than Frio 3a.

For the cement plants and SCPC plants in the Northwest Impact Area and Gulf Impact Areas, CCS costs have a smaller range. In the dedicated pipeline network for the cement plants in the Northwest Impact Area (Exhibit 4-5) and Gulf Impact Area (Exhibit 4-9), costs have a range of $13–25/tonne. SCPC plant CSS costs within these two regional impact areas are within $1–17/tonne. When using a trunkline network, the CCS costs are drastically different and more distant reservoirs become attractive. In the Northwest Impact Area and Gulf Impact Area, CCS costs for the cement plants are within approximately $1–9/tonne of each other, while CCS costs for SCPC plants are within $1–8/tonne. Maha 01 provides the lowest CCS cost option for the cement plant in South Dakota (Northwest Impact Area) even though it is the furthest reservoir from the source. Its cheap storage costs and reduction in transport costs allows it to be more attractive than closer storage reservoirs. The closest storage reservoir to the cement plant in Kansas (Gulf Impact Area), Arbuckle 4, provides the lowest CCS cost, but for $2/tonne more, the source could store its CO_2 in Woodbine 1 or Frio 3a, which are 197 mi and 243 mi further, respectively. In fact, Frio 3a is actually cheaper than Woodbine 1 even though it is the more distant storage reservoir. In the dedicated pipeline network, its low storage costs were not enough to compensate its larger transport costs. Mt. Simon 3, the second closest storage reservoir, is the lowest CCS cost option for the SCPC plant in Missouri (Gulf Impact Area). Frio 3a and Woodbine 1, the furthest storage reservoirs, are unattractive storage options for the SCPC plant in the dedicated pipeline network due to their transport distance; however, in the trunkline network they both provide the same CCS cost, which is only $4/tonne more than the cheapest option. The SCPC plant could choose to transport its captured CO_2 the 632 mi to Woodbine 1 or 728 mi to Frio 3a for storage in a better-quality reservoir. In addition to cost and reservoir quality, storage potential should also be considered when deciding on a storage location. Although not directly assessed in this study, distant reservoirs with a higher storage potential that are cost competitive give projects the option to scale-up operations in the future, which may not be the case if the closest and/or cheapest storage reservoir is selected.

As mentioned in the 2017 Vikara et al. study [5] and 2018 Grant et al. study [24] it is important to analyze each portion of the CCS value chain and understand the cost drivers associated with each link (i.e., CO_2 source location, CO_2 capture rate, storage reservoir quality, and pipeline distance). This analysis demonstrates this approach to determine the lowest CCS cost option and highlight possible first movers within the Central United States. The Central United States has clusters of anthropogenic sources but, depending on the area the source is located within, there could be little to no storage options. However, other areas of the region could provide benefits, so it is key to consider a storage reservoir's quality, if possible, and other options for transporting CO_2 when determining lowest CCS cost options. The NETL-developed resources and models used in this analysis enable evaluation of the economics of each component of the CCS value chain separately or as an integrated whole. [5] [22] [24] However, it is important to note that the cost estimation tools implemented as part of this study provide prospective, screening-level certainty on total project costs for the integrated CCS systems evaluated. This analysis is not intended to represent "as-spent" levels of cost detail for the CCS scenarios evaluated. With that said, the framework implemented offers utility in assessing, comparing, and differentiating CCS integration options on the basis of the first-year breakeven cost metric. Additionally, cost of capture data from the CO_2 point sources reflected NETL's Bituminous baseline and Industrial Carbon Capture resources used for this analysis were generated for a single, specific power or industrial plant configuration. The same point source configurations were used to reflect CO_2 emitters common to the central U.S. region. In actuality, factors affecting levelized CO_2 costs of capture are expected to vary amongst common CO_2 source types. Therefore, it's expected that each real-world point source may have a unique associated cost of capture depending on its specific design and operational characteristics – thereby impacting integrated CCS cost estimates to some degree.

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APPENDIX A: CO_2 PLUME DATA AND CO_2 STORAGE COSTS

This appendix includes data related to the carbon dioxide (CO_2) plume, such as uncertainty area and pressure front area, for the storage reservoirs modeled under both dome and regional dip structural settings based on the mass of CO_2 injected. Storage cost of CO_2 related to each storage reservoir modeled (in nominal 2018 dollars per metric ton [tonne]) is also included. Data can be found in Exhibit A-2 through Exhibit A-4. All values within the tables are rounded to the nearest whole number or in the case of the annual mass of CO_2 injected and CO_2 storage cost, two decimal places.

For simplicity, abbreviations are used within the tables in this appendix. Their definitions are given in Exhibit A-1.

Exhibit A-1. Abbreviations used within tables in Appendix A

Abbreviation	Definition
2018$/tonne	2018 nominal dollars per metric ton of carbon dioxide
AR4	Arbuckle 4 saline storage reservoir
CCS	Carbon capture and storage
CE_KS	Cement production plant in Kansas
CE_SD	Cement production plant in South Dakota
Central Impact Area	Central CCS Network Regional Impact Area
CO_2	Carbon dioxide
Dome	Dome structural setting for storage
ET	Ethanol production plant
FR3A	Frio 3a saline storage reservoir
Gulf Impact Area	Gulf CCS Network Regional Impact Area
ID	Identifier
LA1	Lance 1 saline storage reservoir
MA01	Maha 01 saline storage reservoir
mi^2	Square mile
MI2	Minnelusa 2 saline storage reservoir
MS3	Mount Simon 3 saline storage reservoir
Mt	Million metric tons
NGPP	Natural gas processing plant
Northwest Impact Area	Northwest CCS Network Regional Impact Area
Regional dip	Regional dip structural setting for storage
RR1	Red River 1 saline storage reservoir
SCPC_MO	Supercritical pulverized coal electric power plant in Missouri
SCPC_ND	Supercritical pulverized coal electric power plant in North Dakota
SCPC_WY	Supercritical pulverized coal electric power plant in Wyoming
WO1	Woodbine 1 saline storage reservoir

Exhibit A-2. Areal extent of CO_2 plume, uncertainty, and pressure front boundaries and CO_2 storage cost based on CO_2 injection rate for storage reservoirs modeled in Central Impact Area (dome and regional dip)

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.12 (ET)	0.55 (NGPP)
	Total Mass of CO_2 Stored (Mt)	**4**	**17**
MI2	**Dome Structure Area = 45 mi²**		
	Plume area (mi²)	1	3
	Uncertainty area (mi²)	1	5
	Pressure front area (mi²)	12	55
	CO_2 storage cost (2018$/tonne)	157.83	40.40
	Regional Dip Structure Area = 3,521 mi²		
	Plume area (mi²)	2	9
	Uncertainty area (mi²)	3	15
	Pressure front area (mi²)	33	152
	CO_2 storage cost (2018$/tonne)	168.11	49.50
LA1	**Dome Structure Area = 49 mi²**		
	Plume area (mi²)	0	1
	Uncertainty area (mi²)	0	1
	Pressure front area (mi²)	2	11
	CO_2 storage cost (2018$/tonne)	176.89	41.98
	Regional Dip Structure Area = 3,829 mi²		
	Plume area (mi²)	0	2
	Uncertainty area (mi²)	1	4
	Pressure front area (mi²)	9	39
	CO_2 storage cost (2018$/tonne)	182.32	45.09
RR1	**Dome Structure Area = 695 mi²**		
	Plume area (mi²)	1	3
	Uncertainty area (mi²)	1	5
	Pressure front area (mi²)	10	47
	CO_2 storage cost (2018$/tonne)	172.05	43.42
	Regional Dip Structure Area = 54,224 mi²		
	Plume area (mi²)	1	5
	Uncertainty area (mi²)	2	10
	Pressure front area (mi²)	21	96
	CO_2 storage cost (2018$/tonne)	178.42	48.03
MA01	**Dome Structure Area = 77 mi²**		
	Plume area (mi²)	1	4
	Uncertainty area (mi²)	1	7
	Pressure front area (mi²)	14	65
	CO_2 storage cost (2018$/tonne)	86.44	23.95
	Regional Dip Structure Area = 6,012 mi²		
	Plume area (mi²)	2	10
	Uncertainty area (mi²)	4	18
	Pressure front area (mi²)	39	177
	CO_2 storage cost (2018$/tonne)	94.41	32.55

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.12 (ET)	0.55 (NGPP)
	Total Mass of CO_2 Stored (Mt)	**4**	**17**
AR4	**Dome Structure Area = 406 mi²**		
	Plume area (mi²)	1	3
	Uncertainty area (mi²)	1	5
	Pressure front area (mi²)	10	46
	CO_2 storage cost (2018$/tonne)	100.62	26.76
	Regional Dip Structure Area = 31,649 mi²		
	Plume area (mi²)	1	5
	Uncertainty area (mi²)	2	9
	Pressure front area (mi²)	21	93
	CO_2 storage cost (2018$/tonne)	105.40	30.32
WO1	**Dome Structure Area = 170 mi²**		
	Plume area (mi²)	0	2
	Uncertainty area (mi²)	1	3
	Pressure front area (mi²)	6	28
	CO_2 storage cost (2018$/tonne)	107.49	27.43
	Regional Dip Structure Area = 13,236 mi²		
	Plume area (mi²)	1	4
	Uncertainty area (mi²)	2	7
	Pressure front area (mi²)	16	72
	CO_2 storage cost (2018$/tonne)	112.42	30.60
FR3A	**Dome Structure Area = 15 mi²**		
	Plume area (mi²)	0	1
	Uncertainty area (mi²)	0	1
	Pressure front area (mi²)	3	12
	CO_2 storage cost (2018$/tonne)	102.19	25.24
	Regional Dip Structure Area = 1,163 mi²		
	Plume area (mi²)	0	2
	Uncertainty area (mi²)	1	3
	Pressure front area (mi²)	7	33
	CO_2 storage cost (2018$/tonne)	105.28	27.12
MS3	**Dome Structure Area = 258 mi²**		
	Plume area (mi²)	0	2
	Uncertainty area (mi²)	1	3
	Pressure front area (mi²)	6	28
	CO_2 storage cost (2018$/tonne)	97.73	25.05
	Regional Dip Structure Area = 20,117 mi²		
	Plume area (mi²)	1	4
	Uncertainty area (mi²)	2	8
	Pressure front area (mi²)	17	76
	CO_2 storage cost (2018$/tonne)	102.65	28.32

Note: A zero for any CO_2 plume boundary does not indicate that the areal extent of the boundary is zero; it is just due to rounding to the nearest whole number.

Exhibit A-3. Areal extent of CO_2 plume, uncertainty, and pressure front boundaries and CO_2 storage cost based on CO_2 injection rate for storage reservoirs modeled in Northwest Impact Area (dome and regional dip)

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.97 (CE_SD)	4.33 (SCPC_WY, SCPC_ND)
	Total Mass of CO_2 Stored (Mt)	29	130
MI2	Dome Structure Area = 45 mi^2		
	Plume area (mi^2)	5	25
	Uncertainty area (mi^2)	10	43
	Pressure front area (mi^2)	96	430
	CO_2 storage cost (2018$/tonne)	25.98	11.76
	Regional Dip Structure Area = 3,521 mi^2		
	Plume area (mi^2)	15	68
	Uncertainty area (mi^2)	27	119
	Pressure front area (mi^2)	267	1,192
	CO_2 storage cost (2018$/tonne)	36.02	20.66
LA1	Dome Structure Area = 49 mi^2		
	Plume area (mi^2)	1	5
	Uncertainty area (mi^2)	2	8
	Pressure front area (mi^2)	19	84
	CO_2 storage cost (2018$/tonne)	25.32	8.20
	Regional Dip Structure Area = 3,829 mi^2		
	Plume area (mi^2)	4	17
	Uncertainty area (mi^2)	7	30
	Pressure front area (mi^2)	68	304
	CO_2 storage cost (2018$/tonne)	27.95	11.15

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.97 (CE_SD)	4.33 (SCPC_WY, SCPC_ND)
	Total Mass of CO_2 Stored (Mt)	29	130
RR1	Dome Structure Area = 695 mi^2		
	Plume area (mi^2)	5	21
	Uncertainty area (mi^2)	8	37
	Pressure front area (mi^2)	82	367
	CO_2 storage cost (2018$/tonne)	27.63	11.77
	Regional Dip Structure Area = 54,224 mi^2		
	Plume area (mi^2)	10	43
	Uncertainty area (mi^2)	17	75
	Pressure front area (mi^2)	168	751
	CO_2 storage cost (2018$/tonne)	33.18	16.54
MA01	Dome Structure Area = 77 mi^2		
	Plume area (mi^2)	7	29
	Uncertainty area (mi^2)	11	51
	Pressure front area (mi^2)	115	511
	CO_2 storage cost (2018$/tonne)	16.72	9.10
	Regional Dip Structure Area = 6,012 mi^2		
	Plume area (mi^2)	18	79
	Uncertainty area (mi^2)	31	139
	Pressure front area (mi^2)	311	1,389
	CO_2 storage cost (2018$/tonne)	25.08	17.11

Exhibit A-4. Areal extent of CO_2 plume, uncertainty, and pressure front boundaries and CO_2 storage cost based on CO_2 injection rate for storage reservoirs modeled in Gulf Impact Area (dome and regional dip)

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.97 (CE_KS)	4.33 (SCPC_MO)
	Total Mass of CO_2 Stored (Mt)	29	130
AR4	Dome Structure Area = 406 mi^2		
	Plume area (mi^2)	5	20
	Uncertainty area (mi^2)	8	36
	Pressure front area (mi^2)	80	357
	CO_2 storage cost (2018$/tonne)	17.44	8.43
	Regional Dip Structure Area = 31,649 mi^2		
	Plume area (mi^2)	9	42
	Uncertainty area (mi^2)	16	73
	Pressure front area (mi^2)	164	730
	CO_2 storage cost (2018$/tonne)	21.42	12.31
WO1	Dome Structure Area = 170 mi^2		
	Plume area (mi^2)	3	13
	Uncertainty area (mi^2)	5	22
	Pressure front area (mi^2)	50	223
	CO_2 storage cost (2018$/tonne)	17.42	7.38
	Regional Dip Structure Area = 3,829 mi^2		
	Plume area (mi^2)	7	32
	Uncertainty area (mi^2)	13	56
	Pressure front area (mi^2)	126	564
	CO_2 storage cost (2018$/tonne)	21.22	11.06

Storage Reservoir ID	Annual Mass of CO_2 Injected (Mt)	0.97 (CE_KS)	4.33 (SCPC_MO)
	Total Mass of CO_2 Stored (Mt)	29	130
FR3A	Dome Structure Area = 15 mi^2		
	Plume area (mi^2)	1	5
	Uncertainty area (mi^2)	2	9
	Pressure front area (mi^2)	21	94
	CO_2 storage cost (2018$/tonne)	15.71	5.82
	Regional Dip Structure Area = 1,163 mi^2		
	Plume area (mi^2)	3	15
	Uncertainty area (mi^2)	6	26
	Pressure front area (mi^2)	57	256
	CO_2 storage cost (2018$/tonne)	17.34	7.66
MS3	Dome Structure Area = 258 mi^2		
	Plume area (mi^2)	3	12
	Uncertainty area (mi^2)	5	22
	Pressure front area (mi^2)	49	218
	CO_2 storage cost (2018$/tonne)	15.99	6.91
	Regional Dip Structure Area = 20,117 mi^2		
	Plume area (mi^2)	8	34
	Uncertainty area (mi^2)	13	59
	Pressure front area (mi^2)	133	592
	CO_2 storage cost (2018$/tonne)	19.82	10.63

Appendix B: Pipeline/Trunkline Diameter, Pipeline/Trunkline Distance, Booster Pumps, and CO_2 Transport Costs

This appendix includes the pipeline/trunkline diameter, number of booster pumps, and pipeline/trunkline distance for the pipeline/trunkline segments of the dedicated pipeline and trunkline networks based on carbon dioxide (CO_2) transport rate or trunkline capacity. Transport cost of CO_2 related to each pipeline/trunkline modeled (in nominal 2018 dollars per metric ton [tonne]) are also included. Data can be found in Exhibit B-2 through Exhibit B-10. All values within the tables are rounded to the nearest whole number or in the case of the annual mass of CO_2 transported, trunkline capacity, and CO_2 transport costs, two decimal places.

For simplicity, abbreviations are used within the tables in this appendix. Their definitions are given in Exhibit B-1.

Exhibit B-1. Abbreviations used within tables in Appendix B

Abbreviation	Definition
2018$/tonne	2018 nominal dollars per metric ton of carbon dioxide
AR4	Arbuckle 4 saline storage reservoir
CCS	Carbon capture and storage
CE_KS	Cement production plant in Kansas
CE_SD	Cement production plant in South Dakota
Central Impact Area	Central CCS Network Regional Impact Area
CO_2	Carbon dioxide
ET	Ethanol production plant
FR3A	Frio 3a saline storage reservoir
Gulf Impact Area	Gulf CCS Network Regional Impact Area
HIA	Gathering hub in Iowa for ethanol production plant in Central CCS Network Regional Impact Area
HIL1	Distribution hub in Illinois for Mt. Simon 3 saline storage reservoir in Central CCS Network Regional Impact Area
HIL2	Distribution hub in Illinois for Mt. Simon 3 saline storage reservoir in Gulf CCS Network Regional Impact Area
HKS1	Gathering hub in Kansas for cement production plant in Gulf CCS Network Regional Impact Area
HKS2	Distribution hub in Kansas for Arbuckle 4 saline storage reservoir in Central CCS Network Regional Impact Area
HKS3	Distribution hub in Kansas for Arbuckle 4 saline storage reservoir from cement production plant in Gulf CCS Network Regional Impact Area
HKS4	Distribution hub in Kansas Arbuckle 4 saline storage reservoir from supercritical pulverized coal electric power plant in Gulf CCS Network Regional Impact Area
HMN	Gathering hub in Minnesota for natural gas processing plant in Central CCS Network Regional Impact Area
HMO	Gathering hub in Missouri for supercritical pulverized coal electric power plant in Gulf CCS Network Regional Impact Area

Abbreviation	Definition
HMT1	Distribution hub in Montana for Minnelusa 2 saline storage reservoir in Central CCS Network Regional Impact Area
HMT2	Distribution hub in Montana for Minnelusa 2 saline storage reservoir in Northwest CCS Network Regional Impact Area
HND1	Gathering hub in North Dakota for supercritical pulverized coal electric power plant in Northwest CCS Network Regional Impact Area
HND2	Distribution hub in North Dakota for Red River 1 saline storage reservoir in Central CCS Network Regional Impact Area
HND3	Distribution hub in North Dakota for Red River 1 saline storage reservoir in Northwest CCS Network Regional Impact Area
HNE1	Distribution hub in Nebraska for Maha 01 saline storage reservoir in Central CCS Network Regional Impact Area
HNE2	Distribution hub in Nebraska for Maha 01 saline storage reservoir in Northwest CCS Network Regional Impact Area
HSD	Gathering hub in South Dakota for cement production plant in Northwest CCS Network Regional Impact Area
HTX1	Distribution hub in Texas for Woodbine 1 saline storage reservoir in Central CCS Network Regional Impact Area and Gulf CCS Network Regional Impact Area
HTX2	Distribution hub in Texas for Frio 3a saline storage reservoir in Central CCS Network Impact Area and Gulf CCS Network Regional Impact Area
HWY1	Gathering hub in Wyoming for supercritical pulverized coal electric power plant in Northwest CCS Network Regional Impact Area
HWY2	Distribution hub in Wyoming for Lance 1 saline storage reservoir in Central CCS Network Regional Impact Area and Northwest CCS Network Regional Impact Area
ID	Identifier
in	Inch
LA1	Lance 1 saline storage reservoir
MA01	Maha 01 saline storage reservoir
mi	Mile
MI2	Minnelusa 2 saline storage reservoir
MS3	Mount Simon 3 saline storage reservoir
Mt	Million metric tons
N/A	Not applicable
NGPP	Natural gas processing plant
Northwest Impact Area	Northwest CCS Network Regional Impact Area
RR1	Red River 1 saline storage reservoir
SCPC_MO	Supercritical pulverized coal electric power plant in Missouri
SCPC_ND	Supercritical pulverized coal electric power plant in North Dakota
SCPC_WY	Supercritical pulverized coal electric power plant in Wyoming
WO1	Woodbine 1 saline storage reservoir

Exhibit B-2. Pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost by storage reservoir modeled for dedicated pipeline network in Central Impact Area based on CO_2 transport rate

Storage Reservoir ID	ET Pipeline Distance (mi)	NGPP Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt) 0.12 (ET)	0.55 (NGPP)
MI2	958	722	Pipeline diameter (in)	4	6
			Number of booster pumps	7	12
			CO_2 Transport Cost (2018$/tonne)	543.79	103.17
LA1	880	1,073	Pipeline diameter (in)	4	6
			Number of booster pumps	7	18
			CO_2 Transport Cost (2018$/tonne)	500.10	153.08
RR1	695	460	Pipeline diameter (in)	4	6
			Number of booster pumps	4	7
			CO_2 Transport Cost (2018$/tonne)	394.96	65.65
MA01	585	777	Pipeline diameter (in)	4	6
			Number of booster pumps	4	13
			CO_2 Transport Cost (2018$/tonne)	332.64	111.03

Storage Reservoir ID	ET Pipeline Distance (mi)	NGPP Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt) 0.12 (ET)	0.55 (NGPP)
AR4	487	680	Pipeline diameter (in)	4	6
			Number of booster pumps	3	11
			CO_2 Transport Cost (2018$/tonne)	277.40	97.05
WO1	1,004	1,196	Pipeline diameter (in)	4	6
			Number of booster pumps	6	18
			CO_2 Transport Cost (2018$/tonne)	569.14	169.96
FR3A	1,099	1,292	Pipeline diameter (in)	4	6
			Number of booster pumps	6	20
			CO_2 Transport Cost (2018$/tonne)	622.97	183.71
MS3	480	526	Pipeline diameter (in)	4	6
			Number of booster pumps	2	8
			CO_2 Transport Cost (2018$/tonne)	272.76	74.97

Exhibit B-3. Gathering/distribution pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost for pipeline segments of trunkline network in Central Impact Area based on CO_2 transport rate

Pipeline Segment	Pipeline Type	Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)	
				0.12 (ET)	0.55 (NGPP)
ET-HIA	Gathering	30	Pipeline diameter (in)	4	N/A
			Number of booster pumps	0	N/A
			CO_2 Transport Cost (2018$/tonne)	19.15	N/A
NGPP-HMN	Gathering	30	Pipeline diameter (in)	N/A	6
			Number of booster pumps	N/A	0
			CO_2 Transport Cost (2018$/tonne)	N/A	4.61
HMT1-MI2	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HWY2-LA1	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HND2-RR1	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HNE1-MA01	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HKS2-AR4	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HTX1-WO1	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HTX2-FR3A	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61
HIL1-MS3	Distribution	30	Pipeline diameter (in)	4	6
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	19.15	4.61

Exhibit B-4. Trunkline distance, trunkline diameter, number of booster pumps, and CO_2 transport cost for trunkline segments of trunkline network in Central Impact Area based on trunkline capacity

Trunkline Segment	Trunkline Distance (mi)	Parameter	Annual Trunkline Capacity (Mt)			
			4.50	7.50	18.50	40.00
HIA-HMT1	898	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	26	21	16	9
		CO_2 Transport Cost (2018$/tonne)	28.77	23.10	15.87	11.31
HIA-HWY2	820	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	25	21	16	10
		CO_2 Transport Cost (2018$/tonne)	26.68	21.66	14.92	10.88
HIA-HND2	635	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	18	15	3	6
		CO_2 Transport Cost (2018$/tonne)	20.26	16.39	11.12	7.90
HIA-HNE1	525	Trunkline diameter (in)	12	20	30	36
		Number of booster pumps	15	4	3	6
		CO_2 Transport Cost (2018$/tonne)	16.78	13.64	9.35	6.85
HIA-HKS2	427	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	12	10	7	4
		CO_2 Transport Cost (2018$/tonne)	13.60	11.01	7.37	5.30
HIA-HTX1	944	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	26	21	4	9
		CO_2 Transport Cost (2018$/tonne)	29.82	23.93	16.36	11.76
HIA-HTX2	1,039	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	29	23	17	9
		CO_2 Transport Cost (2018$/tonne)	32.95	26.32	17.89	12.67
HIA-HIL1	420	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	11	2	7	4
		CO_2 Transport Cost (2018$/tonne)	13.12	10.54	7.28	5.24
HMN-HMT1	662	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	19	5	12	7
		CO_2 Transport Cost (2018$/tonne)	21.18	17.18	11.77	8.46
HMN -HWY2	1,013	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	30	25	19	12
		CO_2 Transport Cost (2018$/tonne)	32.65	26.45	18.19	13.33
HMN -HND2	400	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	11	9	2	4
		CO_2 Transport Cost (2018$/tonne)	12.67	10.20	7.03	5.04
HMN-HNE1	717	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	21	17	4	8
		CO_2 Transport Cost (2018$/tonne)	23.06	18.52	12.73	9.30
HMN-HKS2	620	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	17	14	3	6
		CO_2 Transport Cost (2018$/tonne)	19.58	15.80	10.87	7.75
HMN-HTX1	1,136	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	32	26	19	11
		CO_2 Transport Cost (2018$/tonne)	36.11	29.04	19.69	14.21
HMN-HTX2	1.232	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	34	28	21	11
		CO_2 Transport Cost (2018$/tonne)	38.93	31.42	21.46	15.12
HMN-HIL1	466	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	13	10	7	4
		CO_2 Transport Cost (2018$/tonne)	14.80	11.72	7.83	5.67

Exhibit B-5. Pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost by storage reservoir modeled for dedicated pipeline network in Northwest Impact Area based on CO_2 transport rate

Storage Reservoir ID	CE_SD Pipeline Distance (mi)	SCPC_WY Pipeline Distance (mi)	SCPC_ND Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)		
					0.97 (CE_SD)	4.33 (SCPC_WY)	4.33 (SCPC_ND)
MI2	302	336	393	Pipeline diameter (in)	8	12	12
				Number of booster pumps	3	6	11
				CO_2 Transport Cost (2018$/tonne)	27.32	9.95	12.88
LA1	455	191	546	Pipeline diameter (in)	8	12	12
				Number of booster pumps	6	3	15
				CO_2 Transport Cost (2018$/tonne)	41.45	5.57	17.77
RR1	415	541	30	Pipeline diameter (in)	8	12	12
				Number of booster pumps	4	11	0
				CO_2 Transport Cost (2018$/tonne)	37.40	16.42	0.80
MA01	545	222	636	Pipeline diameter (in)	8	12	12
				Number of booster pumps	6	3	17
				CO_2 Transport Cost (2018$/tonne)	49.24	6.30	20.55

Exhibit B-6. Gathering/distribution pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost for pipeline segments of trunkline network in Northwest Impact Area based on CO_2 transport rate

Pipeline Segment	Pipeline Type	Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)		
				0.97 (CE_SD)	4.33 (SCPC_WY)	4.33 (SCPC_ND)
CE_SD-HSD	Gathering	30	Pipeline diameter (in)	8	N/A	N/A
			Number of booster pumps	0	N/A	N/A
			CO_2 Transport Cost (2018$/tonne)	2.88	N/A	N/A
SCPC_WY-HWY1	Gathering	30	Pipeline diameter (in)	N/A	12	N/A
			Number of booster pumps	N/A	0	N/A
			CO_2 Transport Cost (2018$/tonne)	N/A	0.79	N/A
SCPC_ND-HND1	Distribution	30	Pipeline diameter (in)	N/A	N/A	12
			Number of booster pumps	N/A	N/A	0
			CO_2 Transport Cost (2018$/tonne)	N/A	N/A	0.79
HMT2-MI2	Distribution	30	Pipeline diameter (in)	8	12	12
			Number of booster pumps	0	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79	0.79
HWY2-LA1	Distribution	30	Pipeline diameter (in)	8	12	12
			Number of booster pumps	0	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79	0.79
HND3-RR1	Distribution	30	Pipeline diameter (in)	8	12	12
			Number of booster pumps	0	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79	0.79
HNE2-MA01	Distribution	30	Pipeline diameter (in)	8	12	12
			Number of booster pumps	0	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79	0.79

Exhibit B-7. Trunkline distance, trunkline diameter, number of booster pumps, and CO_2 transport cost for trunkline segments of trunkline network in Northwest Impact Area based on trunkline capacity

Trunkline Segment	Trunkline Distance (mi)	Parameter	Annual Trunkline Capacity (Mt)			
			4.50	7.50	18.50	40.00
HSD-HMT2	242	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	7	5	4	2
		CO_2 Transport Cost (2018$/tonne)	7.81	6.05	4.19	2.93
HSD-HWY2	395	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	12	3	7	4
		CO_2 Transport Cost (2018$/tonne)	12.86	10.27	6.97	4.99
HSD-HND3	355	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	9	1	5	2
		CO_2 Transport Cost (2018$/tonne)	11.03	8.72	5.88	4.01
HSD-HNE2	485	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	13	11	8	4
		CO_2 Transport Cost (2018$/tonne)	15.26	12.40	8.39	5.85
HWY1-HMT2	276	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	7	1	4	2
		CO_2 Transport Cost (2018$/tonne)	8.57	6.85	4.60	3.25
HWY1-HWY2	131	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	4	3	2	1
		CO_2 Transport Cost (2018$/tonne)	4.33	3.39	2.23	1.57
HWY1-HND3	481	Trunkline diameter (in)	12	20	30	36
		Number of booster pumps	12	2	1	3
		CO_2 Transport Cost (2018$/tonne)	14.84	12.00	8.03	5.51
HWY1-HNE2	162	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	4	0	2	1
		CO_2 Transport Cost (2018$/tonne)	5.02	3.85	2.60	1.86
HND1-HMT2	334	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	10	8	6	4
		CO_2 Transport Cost (2018$/tonne)	10.85	8.68	5.93	4.42
HND1-HWY2	487	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	15	13	10	6
		CO_2 Transport Cost (2018$/tonne)	15.91	13.04	9.01	6.49
HND1-HND3	39	Trunkline diameter (in)	16	16	24	30
		Number of booster pumps	0	0	0	0
		CO_2 Transport Cost (2018$/tonne)	1.27	0.76	0.49	0.30
HND1-HNE2	577	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	17	14	10	6
		CO_2 Transport Cost (2018$/tonne)	18.61	15.02	10.12	7.35

Exhibit B-8. Pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost by storage reservoir modeled for dedicated pipeline network in Gulf Impact Area based on CO_2 transport rate

Storage Reservoir ID	CE_KS Pipeline Distance (mi)	SCPC_MO Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)	
				0.97 (CE_KS)	4.33 (SCPC_MO)
AR4	291	292	Pipeline diameter (in)	8	12
			Number of booster pumps	3	8
			CO_2 Transport Cost (2018$/tonne)	26.34	9.52
WO1	632	488	Pipeline diameter (in)	8	12
			Number of booster pumps	5	16
			CO_2 Transport Cost (2018$/tonne)	43.98	20.15

Storage Reservoir ID	CE_KS Pipeline Distance (mi)	SCPC_MO Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)	
				0.97 (CE_KS)	4.33 (SCPC_MO)
FR3A	584	728	Pipeline diameter (in)	8	12
			Number of booster pumps	6	18
			CO_2 Transport Cost (2018$/tonne)	52.56	23.05
MS3	457	328	Pipeline diameter (in)	8	12
			Number of booster pumps	4	8
			CO_2 Transport Cost (2018$/tonne)	40.95	10.39

Exhibit B-9. Gathering/distribution pipeline distance, pipeline diameter, number of booster pumps, and CO_2 transport cost for pipeline segments of trunkline network in Gulf Impact Area based on CO_2 transport rate

Pipeline Segment	Pipeline Type	Pipeline Distance (mi)	Parameter	Annual Mass of CO_2 Transported (Mt)	
				0.97 (CE_KS)	4.33 (SCPC_MO)
CE_KS-HKS1	Gathering	30	Pipeline diameter (in)	8	N/A
			Number of booster pumps	0	N/A
			CO_2 Transport Cost (2018$/tonne)	2.88	N/A
SCPC_MO-HMO	Gathering	30	Pipeline diameter (in)	N/A	12
			Number of booster pumps	N/A	0
			CO_2 Transport Cost (2018$/tonne)	N/A	0.79
HKS3-AR4	Distribution	30	Pipeline diameter (in)	8	N/A
			Number of booster pumps	0	N/A
			CO_2 Transport Cost (2018$/tonne)	2.88	N/A
HKS4-AR4	Distribution	30	Pipeline diameter (in)	N/A	12
			Number of booster pumps	N/A	0
			CO_2 Transport Cost (2018$/tonne)	N/A	0.79
HTX1-WO1	Distribution	30	Pipeline diameter (in)	8	12
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79
HTX2-FR3A	Distribution	30	Pipeline diameter (in)	8	12
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79
HIL2-MS3	Distribution	30	Pipeline diameter (in)	8	12
			Number of booster pumps	0	0
			CO_2 Transport Cost (2018$/tonne)	2.88	0.79

Exhibit B-10. Trunkline distance, trunkline diameter, number of booster pumps, and CO_2 transport cost for trunkline segments of trunkline network in Gulf Impact Area based on trunkline capacity

Trunkline Segment	Trunkline Distance (mi)	Parameter	Annual Trunkline Capacity (Mt)			
			4.50	7.50	18.50	40.00
HKS1-HKS3	231	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	7	5	1	2
		CO_2 Transport Cost (2018$/tonne)	7.55	5.85	4.02	2.83
HKS1-HTX1	428	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	12	9	7	4
		CO_2 Transport Cost (2018$/tonne)	13.63	10.72	7.38	5.31
HKS1-HTX2	524	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	14	11	8	4
		CO_2 Transport Cost (2018$/tonne)	16.46	13.11	8.86	6.22
HKS1-HIL2	397	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	11	2	6	3
		CO_2 Transport Cost (2018$/tonne)	12.59	10.01	6.69	4.71
HMO-HKS4	232	Trunkline diameter (in)	12	16	30	36
		Number of booster pumps	7	5	1	2
		CO_2 Transport Cost (2018$/tonne)	7.56	5.87	4.03	2.83
HMO-HTX1	572	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	16	13	9	5
		CO_2 Transport Cost (2018$/tonne)	18.19	14.62	9.75	7.00
HMO-HTX2	668	Trunkline diameter (in)	12	16	24	36
		Number of booster pumps	18	15	11	6
		CO_2 Transport Cost (2018$/tonne)	21.01	17.00	11.52	8.22
HMO-HIL2	268	Trunkline diameter (in)	12	20	24	36
		Number of booster pumps	7	1	4	2
		CO_2 Transport Cost (2018$/tonne)	8.40	6.68	4.51	3.19

Appendix C: Total CCS Costs for Scenarios

This appendix shows total carbon capture and storage (CCS) costs for each scenario in this analysis including a cost break-out of all components in the CCS value chain (i.e., capture, transport, and storage). Cost data is shown for both transport networks (dedicated and trunkline) and storage structural settings (dome and regional dip). All values within the tables are rounded to the nearest whole number or in the case of the annual carbon dioxide (CO_2) capture rate and costs, two decimal places. Exhibit C-2 through Exhibit C-15 show pipeline/trunkline distances and diameters. Costs are listed by storage reservoir and regional impact area and are in nominal 2018 dollars per metric ton (tonne).

For simplicity, abbreviations are used within the tables in this appendix. Their definitions are given in Exhibit C-1.

Exhibit C-1. Abbreviations used within tables in Appendix C

Abbreviation	Definition
2018$/tonne	2018 nominal dollars per metric ton of carbon dioxide
AR4	Arbuckle 4 saline storage reservoir
CCS	Carbon capture and storage
CE_KS	Cement production plant in Kansas
CE_SD	Cement production plant in South Dakota
Central, Central Impact Area	Central CCS Network Regional Impact Area
CO_2	Carbon dioxide
Dedicated	Dedicated pipeline network
Dome	Dome structural setting for storage
ET	Ethanol production plant
FR3A	Frio 3a saline storage reservoir
Gulf, Gulf Impact Area	Gulf CCS Network Regional Impact Area
ID	Identifier
in	Inch
LA1	Lance 1 saline storage reservoir
MA01	Maha 01 saline storage reservoir
mi	Mile
MI2	Minnelusa 2 saline storage reservoir
MS3	Mount Simon 3 saline storage reservoir
Mt/yr	Million metric tons per year
NGPP	Natural gas processing plant
Northwest Impact Area, NW	Northwest CCS Network Regional Impact Area
Regional dip	Regional dip structural setting for storage
RR1	Red River 1 saline storage reservoir
SCPC_MO	Supercritical pulverized coal power plant in Missouri
SCPC_ND	Supercritical pulverized coal power plant in North Dakota
SCPC_WY	Supercritical pulverized coal power plant in Wyoming
Trunkline	Trunkline network
WO1	Woodbine 1 saline storage reservoir

Exhibit C-2. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Central Impact Area (dome)

Central – Dedicated – Dome Capture Rate (Source) – Pipeline Diameter			0.12 Mt/yr (ET) – 4-in pipeline				0.55 Mt/yr (NGPP) – 6-in pipeline			
Storage Reservoir ID	ET Pipeline Distance (mi)	NGPP Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
			2018$/tonne				2018$/tonne			
MI2	958	722	35.22	543.79	157.83	**736.84**	20.92	103.17	40.40	**164.49**
LA1	880	1,073	35.22	500.10	176.89	**712.21**	20.92	153.08	41.98	**215.98**
RR1	695	460	35.22	394.96	172.05	**602.23**	20.92	65.65	43.42	**129.99**
MA01	585	777	35.22	332.64	86.44	**454.30**	20.92	111.03	23.95	**155.90**
AR4	487	680	35.22	277.40	100.62	**413.24**	20.92	97.05	26.76	**144.73**
WO1	1,004	1,196	35.22	569.14	107.49	**711.85**	20.92	169.96	27.43	**218.31**
FR3A	1,099	1,292	35.22	622.97	102.19	**760.38**	20.92	183.71	25.24	**229.87**
MS3	480	526	35.22	272.76	97.73	**405.71**	20.92	74.97	25.05	**120.94**

Exhibit C-3. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Central Impact Area (regional dip)

Central – Dedicated – Regional Dip Capture Rate (Source) – Pipeline Diameter			0.12 Mt/yr (ET) – 4-in pipeline				0.55 Mt/yr (NGPP) – 6-in pipeline			
Storage Reservoir ID	ET Pipeline Distance (mi)	NGPP Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
			2018$/tonne				2018$/tonne			
MI2	958	722	35.22	543.79	168.11	**747.12**	20.92	103.17	49.50	**173.59**
LA1	880	1,073	35.22	500.10	182.32	**717.64**	20.92	153.08	45.09	**219.09**
RR1	695	460	35.22	394.96	178.42	**608.60**	20.92	65.65	48.03	**134.60**
MA01	585	777	35.22	332.64	94.41	**462.27**	20.92	111.03	32.55	**164.50**
AR4	487	680	35.22	277.40	105.40	**418.02**	20.92	97.05	30.32	**148.29**
WO1	1,004	1,196	35.22	569.14	112.42	**716.78**	20.92	169.96	30.60	**221.48**
FR3A	1,099	1,292	35.22	622.97	105.28	**763.47**	20.92	183.71	27.12	**231.75**
MS3	480	526	35.22	272.76	102.65	**410.63**	20.92	74.97	28.32	**124.21**

Exhibit C-4. Total CCS costs for trunkline network by storage reservoir modeled for Central Impact Area (dome)

Central – Trunkline – Dome Capture Rate (Source)					0.12 Mt/yr (ET)				0.55 Mt/yr (NGPP)			
Storage Reservoir ID	ET Distance (mi)	NGPP Distance (mi)	ET Trunkline Diameter (in)	NGPP Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
MI2	958	722	12	12	35.22	67.07	157.83	260.12	20.92	30.40	40.40	91.72
	958	722	16	20	35.22	61.40	157.83	254.45	20.92	26.40	40.40	87.72
	958	722	24	24	35.22	54.17	157.83	247.22	20.92	20.99	40.40	82.31
	958	722	36	36	35.22	49.61	157.83	242.66	20.92	17.68	40.40	79.00
LA1	880	1,073	12	12	35.22	64.98	176.89	277.09	20.92	41.87	41.98	104.77
	880	1,073	16	16	35.22	59.96	176.89	272.07	20.92	35.67	41.98	98.57
	880	1,073	24	24	35.22	53.22	176.89	265.33	20.92	27.41	41.98	90.31
	880	1,073	36	36	35.22	49.18	176.89	261.29	20.92	22.55	41.98	85.45
RR1	695	460	12	12	35.22	58.56	172.05	265.83	20.92	21.89	43.42	86.23
	695	460	16	16	35.22	54.69	172.05	261.96	20.92	19.42	43.42	83.76
	695	460	30	30	35.22	49.42	172.05	256.69	20.92	16.25	43.42	80.59
	695	460	36	36	35.22	46.20	172.05	253.47	20.92	14.26	43.42	78.60
MA01	585	777	12	12	35.22	55.08	86.44	176.74	20.92	32.28	23.95	77.15
	585	777	20	16	35.22	51.94	86.44	173.60	20.92	27.74	23.95	72.61
	585	777	30	30	35.22	47.65	86.44	169.31	20.92	21.95	23.95	66.82
	585	777	36	36	35.22	45.15	86.44	166.81	20.92	18.52	23.95	63.39

Exhibit C-5. Total CCS costs for trunkline network by storage reservoir modeled for Central Impact Area (dome) – continued

Central – Trunkline – Dome Capture Rate (Source)					0.12 Mt/yr (ET)				0.55 Mt/yr (NGPP)			
Storage Reservoir ID	ET Distance (mi)	NGPP Distance (mi)	ET Trunkline Diameter (in)	NGPP Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
AR4	487	680	12	12	35.22	51.90	100.62	187.74	20.92	28.80	26.76	76.48
	487	680	16	16	35.22	49.31	100.62	185.15	20.92	25.02	26.76	72.70
	487	680	24	30	35.22	45.67	100.62	181.51	20.92	20.09	26.76	67.77
	487	680	36	36	35.22	43.60	100.62	179.44	20.92	16.97	26.76	64.65
WO1	1,004	1,196	12	12	35.22	68.12	107.49	210.83	20.92	45.33	27.43	93.68
	1,004	1,196	16	16	35.22	62.23	107.49	204.94	20.92	38.26	27.43	86.61
	1,004	1,196	30	24	35.22	54.66	107.49	197.37	20.92	28.91	27.43	77.26
	1,004	1,196	36	36	35.22	50.06	107.49	192.77	20.92	23.43	27.43	71.78
FR3A	1,099	1,292	12	12	35.22	71.25	102.19	208.66	20.92	48.15	25.24	94.31
	1,099	1,292	16	16	35.22	64.62	102.19	202.03	20.92	40.64	25.24	86.80
	1,099	1,292	24	24	35.22	56.19	102.19	193.60	20.92	30.68	25.24	76.84
	1,099	1,292	36	36	35.22	50.97	102.19	188.38	20.92	24.34	25.24	70.50
MS3	480	526	12	12	35.22	51.42	97.73	184.37	20.92	24.02	25.05	69.99
	480	526	20	16	35.22	48.84	97.73	181.79	20.92	20.94	25.05	66.91
	480	526	24	24	35.22	45.58	97.73	178.53	20.92	17.05	25.05	63.02
	480	526	36	36	35.22	43.54	97.73	176.49	20.92	14.89	25.05	60.86

Exhibit C-6. Total CCS costs for trunkline network by storage reservoir modeled for Central Impact Area (regional dip)

Central – Trunkline – Regional Dip Capture Rate (Source)					0.12 Mt/yr (ET)				0.55 Mt/yr (NGPP)			
Storage Reservoir ID	ET Distance (mi)	NGPP Distance (mi)	ET Trunkline Diameter (in)	NGPP Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
MI2	958	722	12	12	35.22	67.07	168.11	270.40	20.92	30.40	49.50	100.82
	958	722	16	20	35.22	61.40	168.11	264.73	20.92	26.40	49.50	96.82
	958	722	24	24	35.22	54.17	168.11	257.50	20.92	20.99	49.50	91.41
	958	722	36	36	35.22	49.61	168.11	252.94	20.92	17.68	49.50	88.10
LA1	880	1,073	12	12	35.22	64.98	182.32	282.52	20.92	41.87	45.09	107.88
	880	1,073	16	16	35.22	59.96	182.32	277.50	20.92	35.67	45.09	101.68
	880	1,073	24	24	35.22	53.22	182.32	270.76	20.92	27.41	45.09	93.42
	880	1,073	36	36	35.22	49.18	182.32	266.72	20.92	22.55	45.09	88.56
RR1	695	460	12	12	35.22	58.56	178.42	272.20	20.92	21.89	48.03	90.84
	695	460	16	16	35.22	54.69	178.42	268.33	20.92	19.42	48.03	88.37
	695	460	30	30	35.22	49.42	178.42	263.06	20.92	16.25	48.03	85.20
	695	460	36	36	35.22	46.20	178.42	259.84	20.92	14.26	48.03	83.21
MA01	585	777	12	12	35.22	55.08	94.41	184.71	20.92	32.28	32.55	85.75
	585	777	20	16	35.22	51.94	94.41	181.57	20.92	27.74	32.55	81.21
	585	777	30	30	35.22	47.65	94.41	177.28	20.92	21.95	32.55	75.42
	585	777	36	36	35.22	45.15	94.41	174.78	20.92	18.52	32.55	71.99

Exhibit C-7. Total CCS costs for trunkline network by storage reservoir modeled for Central Impact Area (regional dip) – continued

Central – Trunkline – Regional Dip Capture Rate (Source)					0.12 Mt/yr (ET)				0.55 Mt/yr (NGPP)			
Storage Reservoir ID	ET Distance (mi)	NGPP Distance (mi)	ET Trunkline Diameter (in)	NGPP Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
AR4	487	680	12	12	35.22	51.90	105.40	**192.52**	20.92	28.80	30.32	**80.04**
	487	680	16	16	35.22	49.31	105.40	**189.93**	20.92	25.02	30.32	**76.26**
	487	680	24	30	35.22	45.67	105.40	**186.29**	20.92	20.09	30.32	**71.33**
	487	680	36	36	35.22	43.60	105.40	**184.22**	20.92	16.97	30.32	**68.21**
WO1	1,004	1,196	12	12	35.22	68.12	112.42	**215.76**	20.92	45.33	30.60	**96.85**
	1,004	1,196	16	16	35.22	62.23	112.42	**209.87**	20.92	38.26	30.60	**89.78**
	1,004	1,196	24	24	35.22	54.66	112.42	**202.30**	20.92	28.91	30.60	**80.43**
	1,004	1,196	36	36	35.22	50.06	112.42	**197.70**	20.92	23.43	30.60	**74.95**
FR3A	1,099	1,292	12	12	35.22	71.25	105.28	**211.75**	20.92	48.15	27.12	**96.19**
	1,099	1,292	16	16	35.22	64.62	105.28	**205.12**	20.92	40.64	27.12	**88.68**
	1,099	1,292	24	24	35.22	56.19	105.28	**196.69**	20.92	30.68	27.12	**78.72**
	1,099	1,292	36	36	35.22	50.97	105.28	**191.47**	20.92	24.34	27.12	**72.38**
MS3	480	526	12	12	35.22	51.42	102.65	**189.29**	20.92	24.02	28.32	**73.26**
	480	526	20	16	35.22	48.84	102.65	**186.71**	20.92	20.94	28.32	**70.18**
	480	526	24	24	35.22	45.58	102.65	**183.45**	20.92	17.05	28.32	**66.29**
	480	526	36	36	35.22	43.54	102.65	**181.41**	20.92	14.89	28.32	**64.13**

Exhibit C-8. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Northwest Impact Area (dome)

NW – Dedicated – Dome Capture Rate (Source) – Pipeline Diameter				0.97 Mt/yr (CE_SD) – 8-in pipeline				4.33 Mt/yr (SCPC_WY) – 12-in pipeline				4.33 Mt/yr (SCPC_ND) – 12-in pipeline			
Storage Reservoir ID	CE_SD Pipeline Distance (mi)	SCPC_WY Pipeline Distance (mi)	SCPC_ND Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
				2018$/tonne				2018$/tonne				2018$/tonne			
MI2	302	336	393	106.48	27.32	25.98	159.78	65.50	9.95	11.76	87.21	65.50	12.88	11.76	90.14
LA1	455	191	546	106.48	41.45	25.32	173.25	65.50	5.57	8.20	79.27	65.50	17.77	8.20	91.47
RR1	415	541	30	106.48	37.40	27.63	171.51	65.50	16.42	11.77	93.69	65.50	0.80	11.77	78.07
MA01	545	222	636	106.48	49.24	16.72	172.44	65.50	6.30	9.10	80.90	65.50	20.55	9.10	95.15

Exhibit C-9. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Northwest Impact Area (regional dip)

NW – Dedicated – Regional Dip Capture Rate (Source) – Pipeline Diameter				0.97 Mt/yr (CE_SD) – 8-in pipeline				4.33 Mt/yr (SCPC_WY) – 12-in pipeline				4.33 Mt/yr (SCPC_ND) – 12-in pipeline			
Storage Reservoir ID	CE_SD Pipeline Distance (mi)	SCPC_WY Pipeline Distance (mi)	SCPC_ND Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
				2018$/tonne				2018$/tonne				2018$/tonne			
MI2	302	336	393	106.48	27.32	36.02	169.82	65.50	9.95	20.66	96.11	65.50	12.88	20.66	99.04
LA1	455	191	546	106.48	41.45	27.95	175.88	65.50	5.57	11.15	82.22	65.50	17.77	11.15	94.42
RR1	415	541	30	106.48	37.40	33.18	177.06	65.50	16.42	16.54	98.46	65.50	0.80	16.54	82.84
MA01	545	222	636	106.48	49.24	25.08	180.80	65.50	6.30	17.11	88.91	65.50	20.55	17.11	103.16

Exhibit C-10. Total CCS costs for trunkline network by storage reservoir modeled for Northwest Impact Area (dome)

NW – Trunkline – Dome Capture Rate (Source)							0.97 Mt/yr (CE_SD)				4.33 Mt/yr (SCPC_WY)				4.33 Mt/yr (SCPC_ND)			
Storage Reservoir ID	CE_SD Distance (mi)	SCPC_WY Distance (mi)	SCPC_ND Distance (mi)	CE_SD Trunkline Diameter (in)	SCPC_WY Trunkline Diameter (in)	SCPC_ND Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
							2018$/tonne				2018$/tonne				2018$/tonne			
MI2	302	336	394	12	12	12	106.48	13.57	25.98	146.03	65.50	10.15	11.76	87.41	65.50	12.43	11.76	89.69
	302	336	394	16	20	16	106.48	11.81	25.98	144.27	65.50	8.43	11.76	85.69	65.50	10.26	11.76	87.52
	302	336	394	24	24	24	106.48	9.95	25.98	142.41	65.50	6.18	11.76	83.44	65.50	7.51	11.76	84.77
	302	336	394	36	36	36	106.48	8.69	25.98	141.15	65.50	4.83	11.76	82.09	65.50	6.00	11.76	83.26
LA1	455	191	547	12	12	12	106.48	18.62	25.32	150.42	65.50	5.91	8.20	79.61	65.50	17.49	8.20	91.19
	455	191	547	20	16	16	106.48	16.03	25.32	147.83	65.50	4.97	8.20	78.67	65.50	14.62	8.20	88.32
	455	191	547	24	24	24	106.48	12.73	25.32	144.53	65.50	3.81	8.20	77.51	65.50	10.59	8.20	84.29
	455	191	547	36	36	36	106.48	10.75	25.32	142.55	65.50	3.15	8.20	76.85	65.50	8.07	8.20	81.77
RR1	415	541	99	12	12	16	106.48	16.79	27.63	150.90	65.50	16.42	11.77	93.69	65.50	2.85	11.77	80.12
	415	541	99	20	20	16	106.48	14.48	27.63	148.59	65.50	13.58	11.77	90.85	65.50	2.34	11.77	79.61
	415	541	99	24	30	24	106.48	11.64	27.63	145.75	65.50	9.61	11.77	86.88	65.50	2.07	11.77	79.34
	415	541	99	36	36	30	106.48	9.77	27.63	143.88	65.50	7.09	11.77	84.36	65.50	1.88	11.77	79.15
MA01	545	222	637	12	12	12	106.48	21.02	16.72	144.22	65.50	6.60	9.10	81.20	65.50	20.19	9.10	94.79
	545	222	637	16	20	16	106.48	18.16	16.72	141.36	65.50	5.43	9.10	80.03	65.50	16.60	9.10	91.20
	545	222	637	24	24	24	106.48	14.15	16.72	137.35	65.50	4.18	9.10	78.78	65.50	11.70	9.10	86.30
	545	222	637	36	36	36	106.48	11.61	16.72	134.81	65.50	3.44	9.10	78.04	65.50	8.93	9.10	83.53

Exhibit C-11. Total CCS costs for trunkline network by storage reservoir modeled for Northwest Impact Area (regional dip)

NW – Trunkline – Regional Dip Capture Rate (Source)							0.97 Mt/yr (CE_SD)				4.33 Mt/yr (SCPC_WY)				4.33 Mt/yr (SCPC_ND)			
Storage Reservoir ID	CE_SD Distance (mi)	SCPC_WY Distance (mi)	SCPC_ND Distance (mi)	CE_SD Trunkline Diameter (in)	SCPC_WY Trunkline Diameter (in)	SCPC_ND Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
							2018$/tonne				2018$/tonne				2018$/tonne			
MI2	302	336	394	12	12	12	106.48	13.57	36.02	**156.07**	65.50	10.15	20.66	**96.31**	65.50	12.43	20.66	**98.59**
	302	336	394	16	20	16	106.48	11.81	36.02	**154.31**	65.50	8.43	20.66	**94.59**	65.50	10.26	20.66	**96.42**
	302	336	394	24	24	24	106.48	9.95	36.02	**152.45**	65.50	6.18	20.66	**92.34**	65.50	7.51	20.66	**93.67**
	302	336	394	36	36	36	106.48	8.69	36.02	**151.19**	65.50	4.83	20.66	**90.99**	65.50	6.00	20.66	**92.16**
LA1	455	191	547	12	12	12	106.48	18.62	27.95	**153.05**	65.50	5.91	11.15	**82.56**	65.50	17.49	11.15	**94.14**
	455	191	547	20	16	16	106.48	16.03	27.95	**150.46**	65.50	4.97	11.15	**81.62**	65.50	14.62	11.15	**91.27**
	455	191	547	24	24	24	106.48	12.73	27.95	**147.16**	65.50	3.81	11.15	**80.46**	65.50	10.59	11.15	**87.24**
	455	191	547	36	36	36	106.48	10.75	27.95	**145.18**	65.50	3.15	11.15	**79.80**	65.50	8.07	11.15	**84.72**
RR1	415	541	99	12	12	16	106.48	16.79	33.18	**156.45**	65.50	16.42	16.54	**98.46**	65.50	2.85	16.54	**84.89**
	415	541	99	20	20	16	106.48	14.48	33.18	**154.14**	65.50	13.58	16.54	**95.62**	65.50	2.34	16.54	**84.38**
	415	541	99	24	30	24	106.48	11.64	33.18	**151.30**	65.50	9.61	16.54	**91.65**	65.50	2.07	16.54	**84.11**
	415	541	99	36	36	30	106.48	9.77	33.18	**149.43**	65.50	7.09	16.54	**89.13**	65.50	1.88	16.54	**83.92**
MA01	545	222	637	12	12	12	106.48	21.02	25.08	**152.58**	65.50	6.60	17.11	**89.21**	65.50	20.19	17.11	**102.80**
	545	222	637	16	20	16	106.48	18.16	25.08	**149.72**	65.50	5.43	17.11	**88.04**	65.50	16.60	17.11	**99.21**
	545	222	637	24	24	24	106.48	14.15	25.08	**145.71**	65.50	4.18	17.11	**86.79**	65.50	11.70	17.11	**94.31**
	545	222	637	36	36	36	106.48	11.61	25.08	**143.17**	65.50	3.44	17.11	**86.05**	65.50	8.93	17.11	**91.54**

Exhibit C-12. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Gulf Impact Area (dome)

Gulf – Dedicated – Dome Capture Rate (Source) – Pipeline Diameter			0.97 Mt/yr (CE_KS) – 8-in pipeline				4.33 Mt/yr (SCPC_MO) – 12-in pipeline			
Storage Reservoir ID	CE_KS Pipeline Distance (mi)	SCPC_MO Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
			2018$/tonne				2018$/tonne			
AR4	291	292	106.48	26.34	17.44	150.26	65.50	9.52	8.43	83.45
WO1	488	632	106.48	43.98	17.42	167.88	65.50	20.15	7.38	93.03
FR3A	584	728	106.48	52.56	15.71	174.75	65.50	23.05	5.82	94.37
MS3	457	328	106.48	40.95	15.99	163.42	65.50	10.39	6.91	82.80

Exhibit C-13. Total CCS costs for dedicated pipeline network by storage reservoir modeled for Gulf Impact Area (regional dip)

Gulf – Dedicated – Regional Dip Capture Rate (Source) – Pipeline Diameter			0.97 Mt/yr (CE_KS) – 8-in pipeline				4.33 Mt/yr (SCPC_MO) – 12-in pipeline			
Storage Reservoir ID	CE_KS Pipeline Distance (mi)	SCPC_MO Pipeline Distance (mi)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
			2018$/tonne				2018$/tonne			
AR4	291	292	106.48	26.34	21.42	154.24	65.50	9.52	12.31	87.33
WO1	488	632	106.48	43.98	21.22	171.68	65.50	20.15	11.06	96.71
FR3A	584	728	106.48	52.56	17.34	176.38	65.50	23.05	7.66	96.21
MS3	457	328	106.48	40.95	19.82	167.25	65.50	10.39	10.63	86.52

Exhibit C-14. Total CCS costs for trunkline network by storage reservoir modeled for Gulf Impact Area (dome)

Gulf – Trunkline – Dome Capture Rate (Source)					0.97 Mt/yr (CE_KS)				4.33 Mt/yr (SCPC_MO)			
Storage Reservoir ID	CE_KS Distance (mi)	SCPC_MO Distance (mi)	CE_KS Trunkline Diameter (in)	SCPC_MO Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
AR4	291	292	12	12	106.48	13.31	17.44	137.23	65.50	9.14	8.43	83.07
	291	292	16	16	106.48	11.61	17.44	135.53	65.50	7.45	8.43	81.38
	291	292	30	30	106.48	9.78	17.44	133.70	65.50	5.61	8.43	79.54
	291	292	36	36	106.48	8.59	17.44	132.51	65.50	4.41	8.43	78.34
WO1	488	632	12	12	106.48	19.39	17.42	143.29	65.50	19.77	7.38	92.65
	488	632	16	16	106.48	16.48	17.42	140.38	65.50	16.20	7.38	89.08
	488	632	24	24	106.48	13.14	17.42	137.04	65.50	11.33	7.38	84.21
	488	632	36	36	106.48	11.07	17.42	134.97	65.50	8.58	7.38	81.46
FR3A	584	728	12	12	106.48	22.22	15.71	144.41	65.50	22.59	5.82	93.91
	584	728	16	16	106.48	18.87	15.71	141.06	65.50	18.58	5.82	89.90
	584	728	24	24	106.48	14.62	15.71	136.81	65.50	13.10	5.82	84.42
	584	728	36	36	106.48	11.98	15.71	134.17	65.50	9.80	5.82	81.12
MS3	457	328	12	12	106.48	18.35	15.99	140.82	65.50	9.98	6.91	82.39
	457	328	20	20	106.48	15.77	15.99	138.24	65.50	8.26	6.91	80.67
	457	328	24	24	106.48	12.45	15.99	134.92	65.50	6.09	6.91	78.50
	457	328	36	36	106.48	10.47	15.99	132.94	65.50	4.77	6.91	77.18

Exhibit C-15. Total CCS costs for trunkline network by storage reservoir modeled for Gulf Impact Area (regional dip)

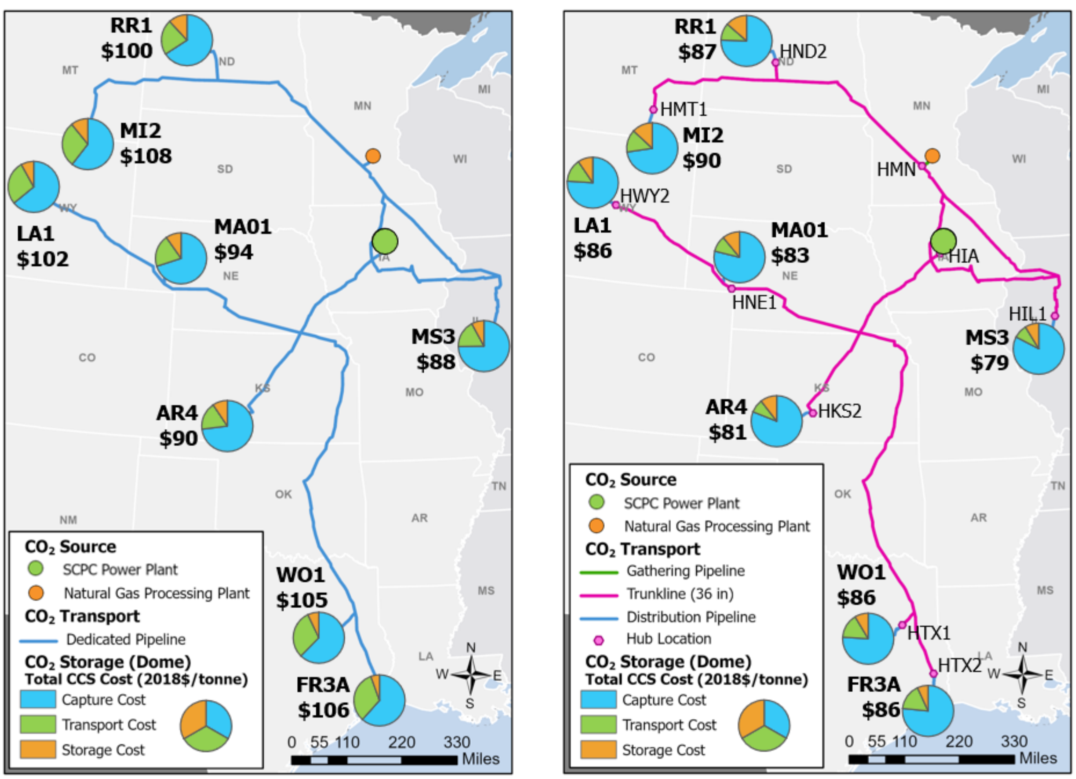
Gulf – Trunkline – Regional Dip Capture Rate (Source)					0.97 Mt/yr (CE_KS)				4.33 Mt/yr (SCPC_MO)			
Storage Reservoir ID	CE_KS Distance (mi)	SCPC_MO Distance (mi)	CE_KS Trunkline Diameter (in)	SCPC_MO Trunkline Diameter (in)	Capture	Transport	Storage	Total CCS	Capture	Transport	Storage	Total CCS
					2018$/tonne				2018$/tonne			
AR4	291	292	12	12	106.48	13.31	21.42	141.21	65.50	9.14	12.31	86.95
	291	292	16	16	106.48	11.61	21.42	139.51	65.50	7.45	12.31	85.26
	291	292	30	30	106.48	9.78	21.42	137.68	65.50	5.61	12.31	83.42
	291	292	36	36	106.48	8.59	21.42	136.49	65.50	4.41	12.31	82.22
WO1	488	632	12	12	106.48	19.39	21.22	147.09	65.50	19.77	11.06	96.33
	488	632	16	16	106.48	16.48	21.22	144.18	65.50	16.20	11.06	92.76
	488	632	24	24	106.48	13.14	21.22	140.84	65.50	11.33	11.06	87.89
	488	632	36	36	106.48	11.07	21.22	138.77	65.50	8.58	11.06	85.14
FR3A	584	728	12	12	106.48	22.22	17.34	146.04	65.50	22.59	7.66	95.75
	584	728	16	16	106.48	18.87	17.34	142.69	65.50	18.58	7.66	91.74
	584	728	24	24	106.48	14.62	17.34	138.44	65.50	13.10	7.66	86.26
	584	728	36	36	106.48	11.98	17.34	135.80	65.50	9.80	7.66	82.96
MS3	457	328	12	12	106.48	18.35	19.82	144.65	65.50	9.98	10.63	86.11
	457	328	20	20	106.48	15.77	19.82	142.07	65.50	8.26	10.63	84.39
	457	328	24	24	106.48	12.45	19.82	138.75	65.50	6.09	10.63	82.22
	457	328	36	36	106.48	10.47	19.82	136.77	65.50	4.77	10.63	80.90

APPENDIX D: ECONOMIES OF SCALE – A CASE STUDY

Economies of scale are present at each link in the CCS value chain. To demonstrate the effects on a large and small source, we performed a sensitivity analysis by modeling a SCPC power plant at the same location as the ethanol plant for both the dedicated pipeline and trunkline networks. This sensitivity analysis also showed the impact of a larger source without local storage.

As discussed in Section 4.1, the ethanol plant has high CCS costs due to its low capture rate and distance from storage reservoirs. However, if a plant with a larger capture rate is at the same location as the ethanol plant, CCS costs will be different. Since a cluster of electric power plants are around the ethanol plant's location, a SCPC electric power plant (with the same key items as those in Exhibit 3-1) was chosen to model a case study for a larger source (Exhibit D-1). Exhibit D-2 and Exhibit D-3 compare the costs for each component of the CCS value chain and overall CCS costs between the ethanol plant (left side of tables) and SCPC plant at the same location as the ethanol plant (right side of tables) for both the dedicated pipeline network and trunkline network, respectively.

Exhibit D-1. Maps showing total CCS cost and percent of each component for an SCPC plant at the same location as the ethanol plant in the Central Impact Area for dedicated pipeline (left) and trunkline (right) networks (dome)



As mentioned in Section 2, the methodology to achieve the total CCS costs used a concept from studies by Grant et al. [22] [24] that applied a modular approach for evaluating $/tonne costs for a given CO_2 source, storage option, and transportation network by taking the sum of each individual capture, storage, and transport cost. This methodology is demonstrated in Exhibit D-2 and Exhibit D-3. It is important to note that the method of obtaining transport costs is fundamentally different between the two transportation networks. As mentioned in Section 2.4.1, the dedicated pipeline network has one pipeline connecting a CO_2 source to a storage reservoir providing a single cost for transportation. For a trunkline network, there are multiple segments connecting a CO_2 source to a storage reservoir so each segment has to be summed to achieve the overall transport cost. For example, if the ethanol plant wanted to store its captured CO_2 in Minnelusa 2 (MI2) utilizing the trunkline network, a 30-mi, 4-in dedicated gathering pipeline (ET – HIA in Exhibit D-3) would connect to the gathering hub or entry hub (HIA) of the trunkline. At the other end of the 898 mi, 36-in trunkline segment, the HMT1 distribution hub connects to a 30-mi, 4-in dedicated distribution pipeline to the Minnelusa 2 storage reservoir (HMT1 – MI2 in Exhibit D-3). The total transport costs would be the sum of these three segments (i.e., \$19.15/tonne + \$11.31/tonne + \$19/15/tonne = \$49.61/tonne). Adding this total to the capture cost (\$35.22/tonne) and storage costs (\$157.83/tonne) gives a total CCS cost of \$242.66/tonne to store the Ethanol Plants' captured CO_2 in the Minnelusa 2 storage reservoir (Exhibit D-3)

Capture costs stay the same whether using the dedicated pipeline network or trunkline network. The cost of capture for the SCPC plant is almost double that of the ethanol plant due to the lower purity of its CO_2 stream and extra mass of CO_2 captured (Exhibit D-2 and Exhibit D-3). Storage costs also stay the same between both transportation networks. The storage costs for the ethanol plant are \$77–170/tonne more expensive than the SCPC plant due to its lower injection rate (0.12 Mt/yr versus 4.33 Mt/yr for the SCPC plant) and total mass of captured CO_2 stored. The lower capture rate for the ethanol plant is also a factor for the larger transport costs, which are \$256–588/tonne more expensive than the SCPC plant in the dedicated pipeline network (Exhibit D-2). Transport costs for the ethanol plant in the trunkline network are significantly reduced and are \$18/tonne more expensive than the SCPC plant with the difference in costs due to the gathering and distribution pipelines (Exhibit D-3). CCS costs for the SCPC plant using a dedicated pipeline are \$318–654/tonne cheaper than those for the ethanol plant even though the transport distances are far; the higher capture rate provides an advantage to the SCPC plant. CCS costs for the SCPC plant are \$84–155/tonne cheaper in the trunkline network even though the ethanol plant benefits more from the lower unit cost of the trunkline network. Costs associated with the trunkline portion of the network are the same for both sources since unit costs for the 36-in. trunkline are based on a transport rate of 40 Mt/yr.

Exhibit D-2. Comparison of costs across CCS value chain for SCPC plant in same location as ethanol plant for dedicated pipeline network

Dedicated Pipeline Network		Cost ($/tonne)
Capture	0.12 Mt/yr	35.22
Storage	*Dome*	
MI2		157.83
LA1		176.89
RR1		172.05
MA01		86.44
AR4		100.62
WO1		107.49

Dedicated Pipeline Network		Cost ($/tonne)
Capture	4.33 Mt/yr	65.50
Storage	*Dome*	
MI2		11.76
LA1		8.20
RR1		11.77
MA01		9.10
AR4		8.43
WO1		7.38

Dedicated Pipeline Network			Cost ($/tonne)
FR3A			102.19
MS3			97.73
Transport			
Route	*Diameter (in)*	*Distance (mi)*	
ET – MI2	4	958	543.79
ET – LA1	4	880	500.10
ET – RR1	4	695	394.96
ET – MA01	4	585	332.64
ET – AR4	4	487	277.40
ET – WO1	4	1,004	569.14
ET – FR3A	4	1,099	622.97
ET – MS3	4	480	272.76
CCS MI2			**736.84**
CCS LA1			**712.21**
CCS RR1			**602.23**
CCS MA01			**454.30**
CCS AR4			**413.24**
CCS WO1			**711.85**
CCS FR3A			**760.38**
CCS MS3			**405.71**

Dedicated Pipeline Network			Cost ($/tonne)
FR3A			5.82
MS3			6.91
Transport			
Route	*Diameter (in)*	*Distance (mi)*	
SCPC – MI2	12	958	31.02
SCPC – LA1	12	880	28.55
SCPC – RR1	12	695	22.27
SCPC – MA01	12	585	19.00
SCPC – AR4	12	487	15.74
SCPC – WO1	12	1,004	32.11
SCPC – FR3A	12	1,099	35.03
SCPC – MS3	12	480	15.25
CCS MI2			**108.28**
CCS LA1			**102.25**
CCS RR1			**99.54**
CCS MA01			**93.60**
CCS AR4			**89.67**
CCS WO1			**104.99**
CCS FR3A			**106.35**
CCS MS3			**87.66**

For the ethanol plant and SCPC plant in the dedicated pipeline network (Exhibit D-2), Mt. Simon 3 is the lowest CCS cost option at $406/tonne and $88/tonne, respectively. Its short transport distance (480 mi) and decent storage reservoir quality (Exhibit 3-4) factor into this low cost for each source. When looking at the trunkline network (Exhibit D-3), Mt. Simon 3 is still the lowest CCS cost option for the SCPC power plant at $79/tonne, while Maha 01 is the lowest for the ethanol plant at around $167/tonne, a significant reduction in costs for the ethanol plant. The trunkline network allows a source to consider storage reservoirs further away. In the dedicated pipeline network, the ethanol plant and SCPC plant would have considered Arbuckle 4 as their second-best storage options due to it being only 7 mi further than Mt. Simon 3; however, in the trunkline network, Mt. Simon 3 would be the second-best option for the ethanol plant, while Arbuckle 4 would be second best for the SCPC plant. The smaller unit costs associated with the SCPC power plant are due to the economies of scale at each point in the value chain. Economies of scale usually benefit a larger source (i.e., one with a larger capture rate). Increasing the mass of CO_2 allows the unit costs of transport and storage to decrease.

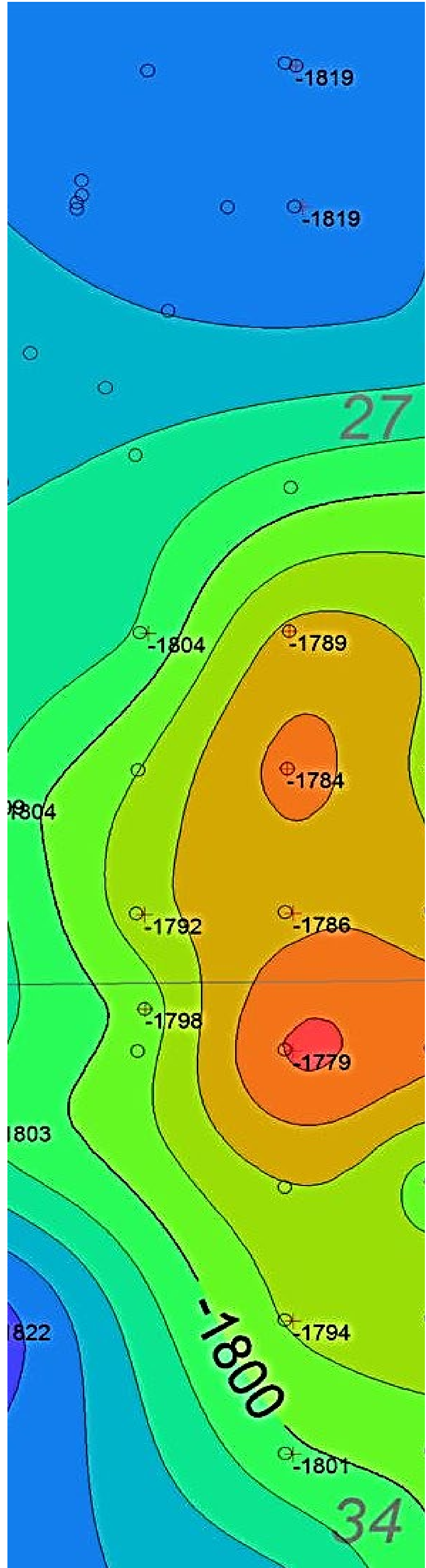
Exhibit D-3. Comparison of costs across CCS value chain for SCPC plant in same location as ethanol plant for trunkline network

Trunkline Network		Cost ($/tonne)
Capture	0.12 Mt/yr	35.22
Storage	*Dome*	
MI2		157.83
LA1		176.89
RR1		172.05
MA01		86.44
AR4		100.62
WO1		107.49
FR3A		102.19
MS3		97.73
Transport		

Trunkline Network		Cost ($/tonne)
Capture	4.33 Mt/yr	65.50
Storage	*Dome*	
MI2		11.76
LA1		8.20
RR1		11.77
MA01		9.10
AR4		8.43
WO1		7.38
FR3A		5.82
MS3		6.91
Transport		

Trunkline Network			**Cost ($/tonne)**
Route	*Diameter (in)*	*Distance (mi)*	
ET – HIA	4	30	19.15
HIA – HMT1	36	898	11.31
HIA – HWY2	36	820	10.88
HIA – HND2	36	635	7.90
HIA – HNE1	36	525	6.85
HIA – HKS2	36	427	5.30
HIA – HTX1	36	944	11.76
HIA – HTX2	36	1,039	12.67
HIA – HIL1	36	420	5.24
HMT1 – MI2	4	30	19.15
HWY2 – LA1	4	30	19,15
HND2 – RR1	4	30	19.15
HNE1 – MA01	4	30	19.15
HKS2 – AR4	4	30	19.15
HTX1 – WO1	4	30	19.15
HTX2 – FR3A	4	30	19.15
HIL1 – MS3	4	30	19.15
CCS MI2			**242.66**
CCS LA1			**261.29**
CCS RR1			**253.47**
CCS MA01			**166.81**
CCS AR4			**179.44**
CCS WO1			**192.77**
CCS FR3A			**188.38**
CCS MS3			**176.49**

Trunkline Network			**Cost ($/tonne)**
Route	*Diameter (in)*	*Distance (mi)*	
SCPC – HIA	12	30	0.79
HIA – HMT1	36	898	11.31
HIA – HWY2	36	820	10.88
HIA – HND2	36	635	7.90
HIA – HNE1	36	525	6.85
HIA – HKS2	36	427	5.30
HIA – HTX1	36	944	11.76
HIA – HTX2	36	1,039	12.67
HIA – HIL1	36	420	5.24
HMT1 – MI2	12	30	0.79
HWY2 – LA1	12	30	0.79
HND2 – RR1	12	30	0.79
HNE1 – MA01	12	30	0.79
HKS2 – AR4	12	30	0.79
HTX1 – WO1	12	30	0.79
HTX2 – FR3A	12	30	0.79
HIL1 – MS3	12	30	0.79
CCS MI2			**90.15**
CCS LA1			**86.16**
CCS RR1			**86.75**
CCS MA01			**83.03**
CCS AR4			**80.81**
CCS WO1			**86.22**
CCS FR3A			**85.57**
CCS MS3			**79.23**



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