Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

SIMULATION OF CCUS HUB BUILD-OUT SCENARIOS

Plains CO_2 Reduction (PCOR) Partnership Initiative
Task 4 – Deliverable 9

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EXECUTIVE SUMMARY

Comprising ten states and four Canadian provinces, the Plains CO_2 Reduction (PCOR) Partnership region is home to abundant and diverse sources of anthropogenic CO_2 (e.g., coal- and gas-fired power plants, gas-processing plants, ethanol plants), fitting geology for CO_2 storage and utilization, a history of CO_2 transport and expanding pipeline infrastructure, and an established industrial/energy commercial base.

Although significant CO_2 storage resources exist within and near the PCOR Partnership region, many CO_2 emission sources in the PCOR region, including most ethanol production facilities and a significant number of coal- and natural-gas-fired electric generating facilities, do not reside in these favorable storage areas. Development of carbon capture, utilization, and storage (CCUS) projects for these facilities will require the construction of transportation pipelines to connect these sources of CO_2 to the storage formations. Often, the most cost-effective solution for multiple facilities to pursue a CCUS project is by collectively creating a pipeline network that combines their CO_2 streams and transports the CO_2 stream volume to a single storage target (consisting of one or multiple injection wells in one area), referred to as CCUS hubs or hub and cluster development. The transport and storage components of the system may be owned collectively by the capture facilities or by a third party.

Multiple industrial facilities (CO_2 emission sources) and geologic storage sites located within and near the continental United States portion of the PCOR Partnership region were reduced to a select number of emission sources based on estimated carbon capture costs and a selected number of storage locations based on proximity to the facilities. This subset of data provided inputs for simulating CCUS hub development in SimCCS Gateway software. SimCCS Gateway identifies potential pipeline networks that could connect the emission sources with the storage sites by using internal routing algorithms. Simulations of these CCUS hub scenarios, which included carbon capture and pipeline costs, offer potential combinations of emission sources and geologic storage sites that could be developed into CCUS hub projects. The optimization of project costs will be driven by multiple factors, but pipeline costs will be less cost-effective as smaller sources are more geographically spread out. Terrain can also play a role in site selection as additional pumps or larger OD piping will be needed to combat pressure losses if flow moves toward higher elevations. However, based on the limited number of economic factors considered, all modeled scenarios are suggested to be profitable given the US$85/tonne of CO_2 stored for Section 45Q tax credits when evaluating the entire scenario's network.

As the number of CCUS projects continue to grow in the PCOR Partnership region, CCUS hub development will be important for maximizing the available CO_2 storage resource. Additional optimization and savings in costs could be investigated to understand how coordination among CCUS hubs could benefit multiple projects. Examples may include overlapping pipeline rights-of-way, optimizing available storage space, or sharing infrastructure or utilities (e.g., maximizing/ coordinating electrical generation for project operations).

SIMULATION OF CCUS HUB BUILD-OUT SCENARIOS

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, funded by the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), the North Dakota Industrial Commission's Oil and Gas Research Program and Lignite Research Program, along with more than 240 public and private partners, is accelerating the deployment of carbon capture utilization and storage (CCUS) technology. The PCOR Partnership is focused on a region comprising ten U.S. states and four Canadian provinces in the upper Great Plains and northwestern regions of North America. It is led by the University of North Dakota Energy & Environmental Research Center (EERC), with support from the University of Wyoming and the University of Alaska Fairbanks.

The deployment of commercial CCUS projects in the PCOR Partnership region includes geologic storage of carbon dioxide (CO_2) in saline formations (dedicated storage) and utilization of CO_2 stored in association with enhanced oil recovery (EOR) (CO_2 EOR and associated storage). Commercialization of CCUS has led to the expansion of existing CO_2 pipeline transportation networks and construction of new CO_2 pipelines connecting major industrial CO_2 sources within the PCOR Partnership region to geologic formations best suited for permanent storage. In 2021, Denbury Resources extended the Greencore CO_2 pipeline system from its Bell Creek operation in southeastern Montana to its Cedar Hills South Unit operations bordering Montana and western North Dakota. In addition, other companies such as Summit Carbon Solutions, Navigator CO_2 Ventures LLC, and Archer Daniels Midland (ADM) have announced and are actively developing new CO_2 pipelines within the PCOR Partnership region. The emission sources within the announced projects were not consider within this review.

A number of CO_2-emitting facilities (e.g., power plants, ethanol facilities, etc.) in the PCOR Partnership region do not reside in the immediate areas with favorable geologic storage opportunities (Figure 1). To further accelerate widespread deployment of CCUS, efficiently utilizing storage resources and minimizing project development and operational costs, development of CCUS hubs and CO_2 pipeline networks is needed. Often, the most cost-effective solution for multiple facilities to pursue a CCUS project is by collectively creating a pipeline network that combines their CO_2 streams and transports the CO_2 stream volume to a single storage target (consisting of one or multiple injection wells in one area), referred to as CCUS hubs or hub and cluster development. The transport and storage components of the system may be owned collectively by the capture facilities or by a third party.

An evaluation using SimCCS Gateway software, developed at Indiana University, identifies ideal sink/source matching and cost-effective pipeline network routes, and the simulated results can inform development of possible CCUS hubs across the PCOR Partnership region. Cost

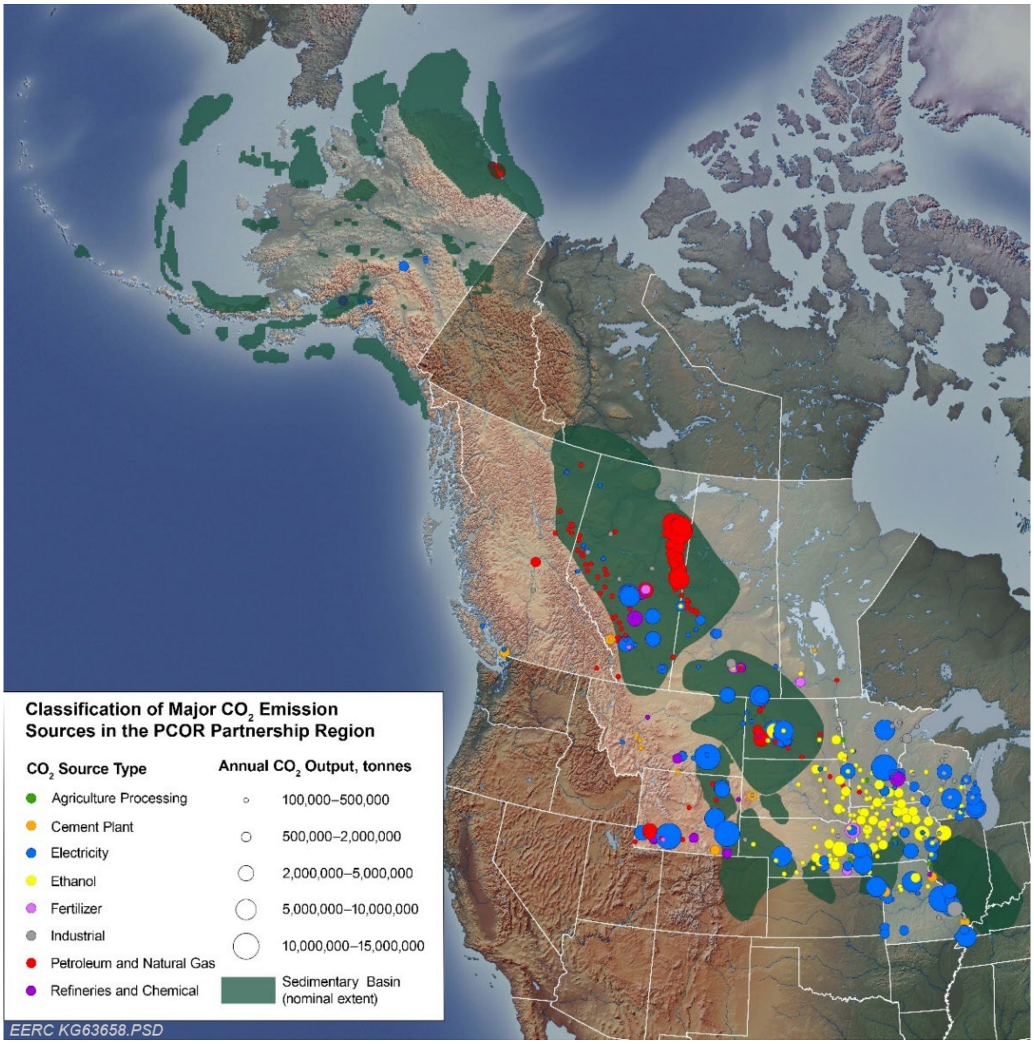

Figure 1. CO_2 emission sources and sedimentary basins in the PCOR Partnership region (Peck and others, 2021).

information used to support SimCCS Gateway results was developed using the Integrated Environmental Control Model (IECM). The IECM provides a generalized approach for estimating capture costs for facilities across the PCOR region. This cost information was verified using the EERC's in-house knowledge of capture system costs from front-end engineering and design (FEED) studies on developing CCUS projects in the PCOR Partnership region. Results of the simulated hub scenarios described in this report offer insight into optimizing project costs and potential areas for future CCUS hub development. However, one significant caveat to the simulated scenarios and the insights provided is that the software does not consider other business or investment decisions or regulatory considerations (e.g., Class VI primacy, pore space law, long-term liability, etc.). For example, while the software may find the optimized costs and pipeline routing based on algorithms within the software for a hypothetical CCUS hub project in Iowa should route to Illinois rather North Dakota, a project developer may actually elect to pursue storage in North Dakota because of a favorable regulatory environment, as the state has primacy on Class VI wells (CO_2 injection). Therefore, the reader should understand that while the SimCCS Gateway tool provides valuable information for project planning, a wider range of considerations are necessary as CCUS hub projects are being developed.

POTENTIAL CCUS INFRASTRUCTURE DEVELOPMENT IN THE PCOR PARTNERSHIP REGION

The PCOR Partnership region has over 500 large stationary CO_2 emission sources, defined as those facilities emitting more than 100,000 metric tons/year (Figure 1). Currently, most CCUS projects target coal-fired electric generating facilities and ethanol production plants. The PCOR Partnership region has about 150 electric generating facilities, with many of those located in the eastern parts of the region. About 120 ethanol facilities are found primarily in Iowa, South Dakota, Minnesota, North Dakota, and Nebraska, and a number of these facilities are part of developing CCUS projects, including hub projects such as Summit Carbon Solutions[1] and Navigator's Heartland Greenway[2] projects (Figure 2).

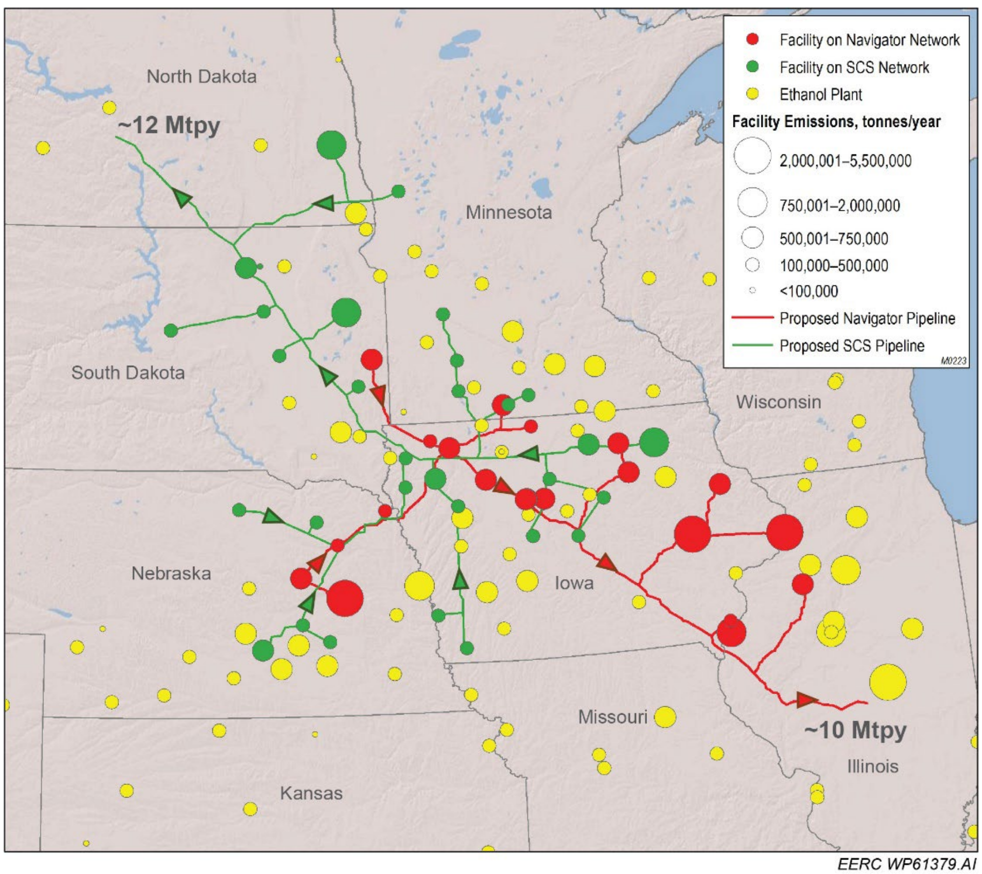

Figure 2. Summit Carbon Solutions- and Navigator-proposed pipeline networks and ethanol plant locations (Peck and others, 2022).

[1] https://summitcarbonsolutions.com/ (accessed 2023).
[2] https://heartlandgreenway.com/ (accessed March 2023).

Existing CO_2 pipelines cover about 1200 miles within the PCOR Partnership region. Earlier CO_2 pipeline development focused on delivering CO_2 for EOR efforts, e.g., Dakota Gasification Company's (DGC's) pipeline delivering CO_2 from North Dakota to the Weyburn/Midale oil fields in southern Saskatchewan and Salt Creek/Greencore pipelines in Wyoming to CO_2 EOR fields in Wyoming and southeastern Montana. More recent development includes the Alberta Carbon Trunk Line (ACTL) near Edmonton, Alberta, which is a CO_2 hub delivering CO_2 from multiple facilities to EOR fields south of the city. Current pipeline development efforts include not only the aforementioned Summit Carbon Solutions and Heartland Greenway projects but also a number of announced CCUS hub projects in the province of Alberta (Figure 3). Furthermore, the state of Wyoming has also designated CO_2 pipeline corridors under the Wyoming Pipeline Corridor Initiative that lay the groundwork for CCUS project expansion in the state.

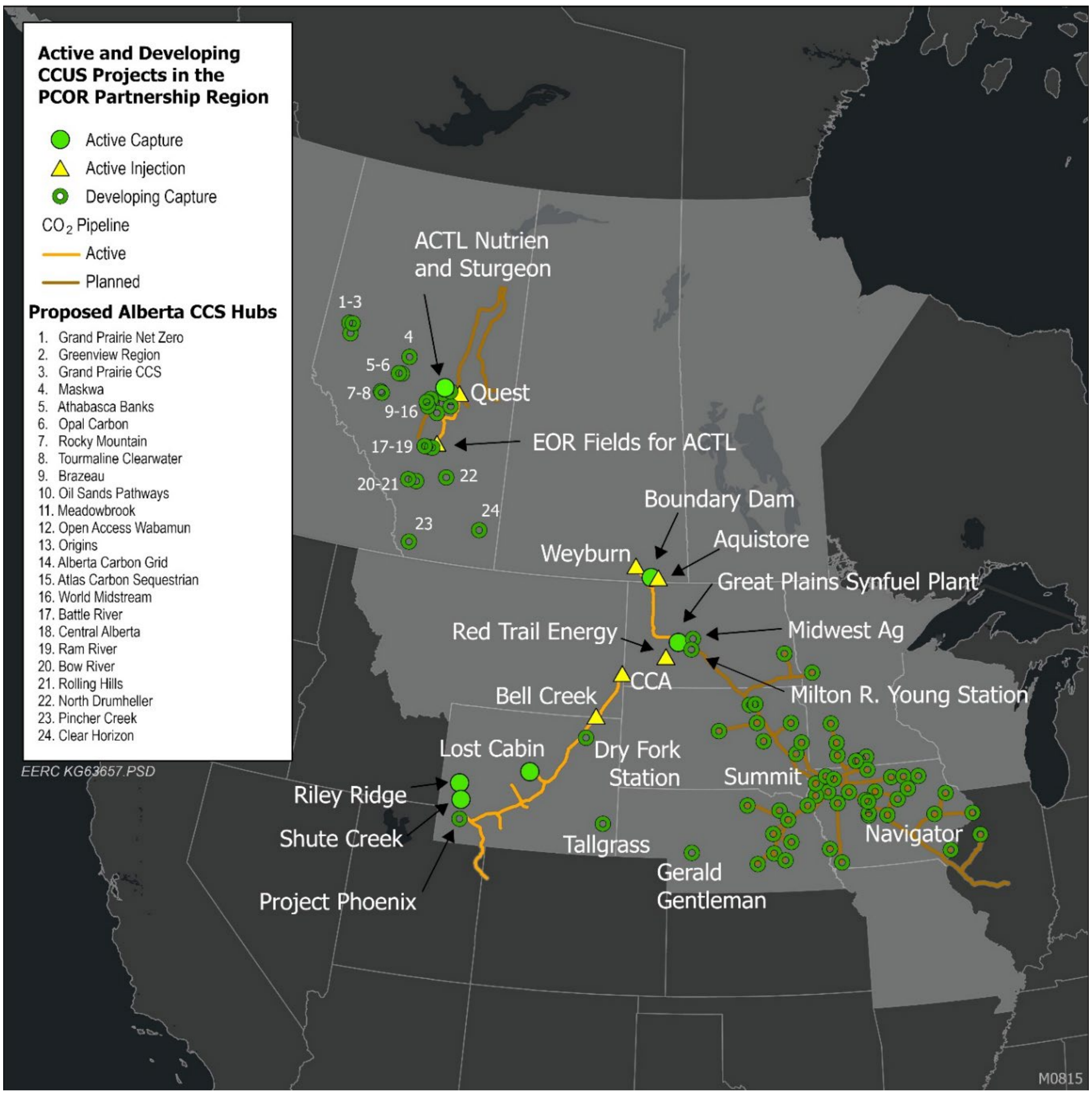

Figure 3. Current and developing CCUS projects in the PCOR Partnership region.

Geologic storage sites and multiple industrial facilities (CO_2 emission sources) located within and near the continental U.S. portion of the PCOR Partnership region were reduced to a select number of emission sources based on carbon capture costs and selected geologic storage locations based on proximity to the facilities. This sub set of data provided inputs for simulating CCUS hub development in the SimCCS Gateway software tool (described in the following section). SimCCS Gateway used capture cost inputs described in the capture cost section (IECM, Emissions & Generation Resource Integrated Database [eGrid], and FEED studies). Several scenarios run in SimCCS Gateway were performed by selecting from the aforementioned subset of emission sources and storage areas, and then SimCCS Gateway software algorithms optimized the potential pipeline routes and identified the most logical sets of emission sources to include in each scenario's network. The pipeline networks identified within these scenarios were pulled into a transport cost model, as described in the pipeline cost section, for comparison to SimCCS Gateway cost calculations and for additional evaluation of overall cost of the project.

Identification of Source-Sinks and Pipeline Routing with CCS Tool

SimCCS Gateway is a software tool that was originally introduced in 2009 for making carbon dioxide capture and storage decisions (SimCCS Gateway, 2022). SimCCS Gateway allows the upload of sets of CO_2 source and CO_2 sink (storage) data from a Microsoft Excel template and was leveraged for this study to identify optimal pipeline routings as part of a hypothetical CCUS hub development (Middleton et al., 2020). The data sets include fixed and variable costs associated with CO_2 capture and storage and total capture volumes and storage resource. These data are plotted against the software's pipeline cost surface map, which identifies regions of elevated cost for pipeline routing including adverse terrain, high-population-density municipalities, reservations, national/state parks, etc. SimCCS Gateway software allows the user to develop scenarios by selecting sources and sinks to use for the development of a hypothetical optimized set of routings based entirely on the cost surface and the sources and sinks locations. Figure 4 shows the candidate CO_2 sources in light blue and candidate sink well locations in gray used to develop a candidate pipeline network in SimCCS Gateway for the North Dakota–Minnesota region. These CO_2 sources are a combination of power plants, ethanol plants, and other industrial sources listed in Table A-16 of Appendix A.

The sink locations (potential storage hub locations) shown in Figure 5 are based on the EERC's knowledge of available and suitable geologic formations. The specific sink locations selected for inclusion were saline formations with larger storage resource potential and lower estimated storage costs within targeted regions. The software's cost surface map, proximity to defined CO_2 sources, and pipeline rights-of-way were also considered within the software.

A candidate pipeline network was then generated in SimCCS Gateway that shows an optimal network of possible pipeline routes for hub development, as shown in Figure 5. The capital recovery rate, length of project, and annual capture target were specified to setup a hypothetical CCUS hub scenario to identify an optimized capture solution.

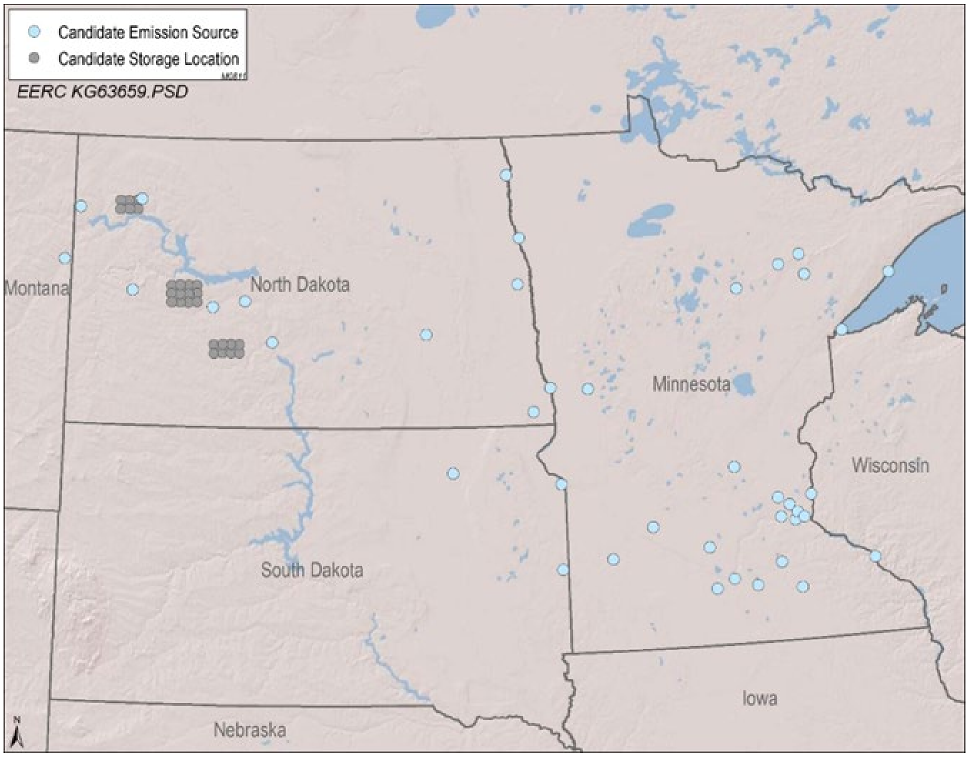

Figure 4. Candidate CO_2 emission source locations (light blue) and candidate storage/sink locations (gray) used for evaluating the North Dakota–Minnesota region.

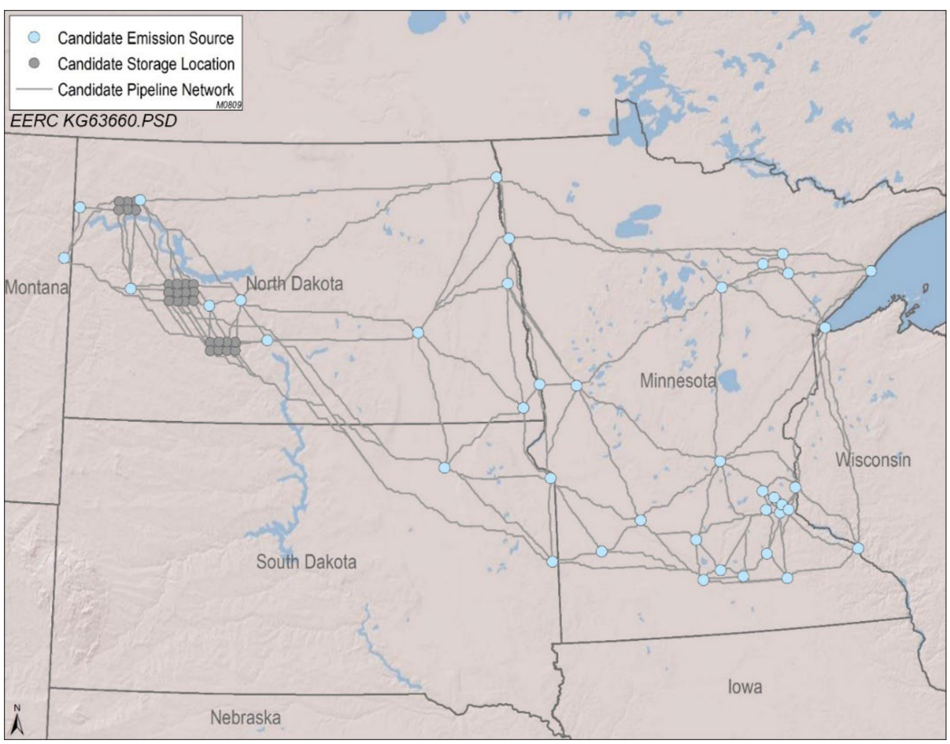

Figure 5. Candidate network showing optimal routes for pipeline connections between CO_2 sources and candidate storage well locations.

SimCCS Gateway software uses machine learning algorithms to identify optimized routings between sources and sinks using the user-specified CO_2 capture and storage cost information to achieve the targeted capture and storage volumes. This proposed network excludes sources that have higher capture costs or more expensive pipeline routing requirements to minimize network costs while hitting the user-defined annual capture target. Figure 6 shows the network identified for a capture target of 33% of the total scenario source emissions or approximately 16.8 million metric tons of CO_2 emissions annually.

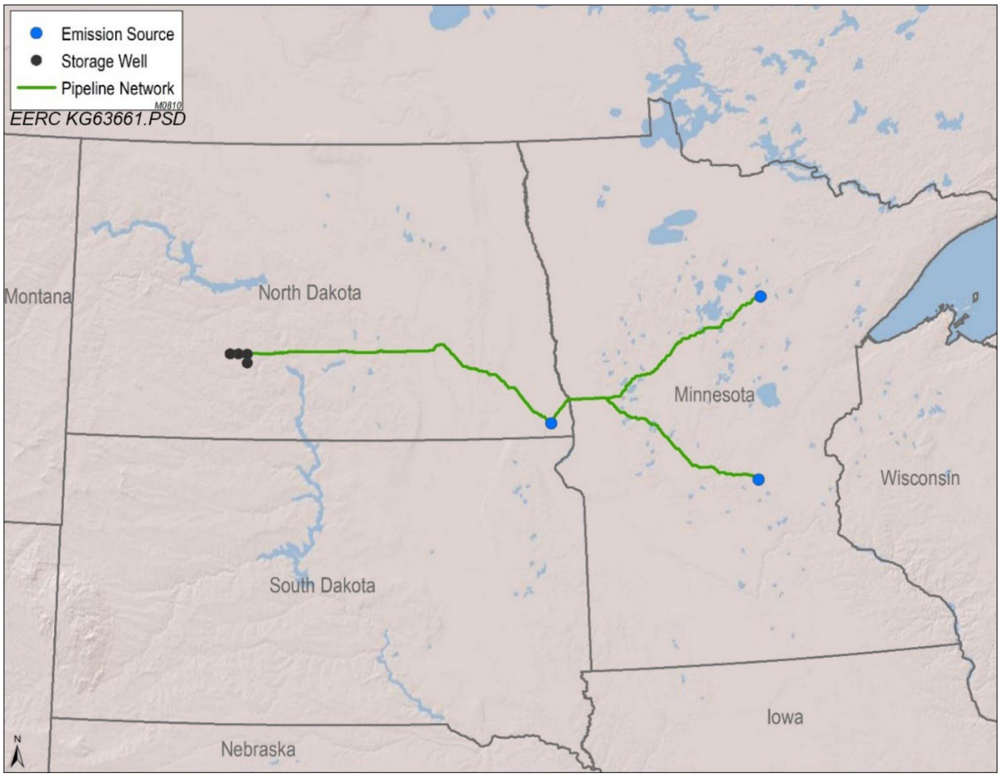

Figure 6. An optimized network layout targeting 33% of the total network CO_2 source emissions (16.8 million metric tons annually).

The sources selected represent the optimized network to capture approximately 33% of the emissions from sources in the candidate network. A 51% capture scenario is also simulated to allow for comparisons between proposed network layouts as network CO_2 capacity increases, shown in Figure 7. In general, as smaller sources are added with higher capture costs and smaller transport volumes, the total aggregated network cost of capture and storage goes up slightly.

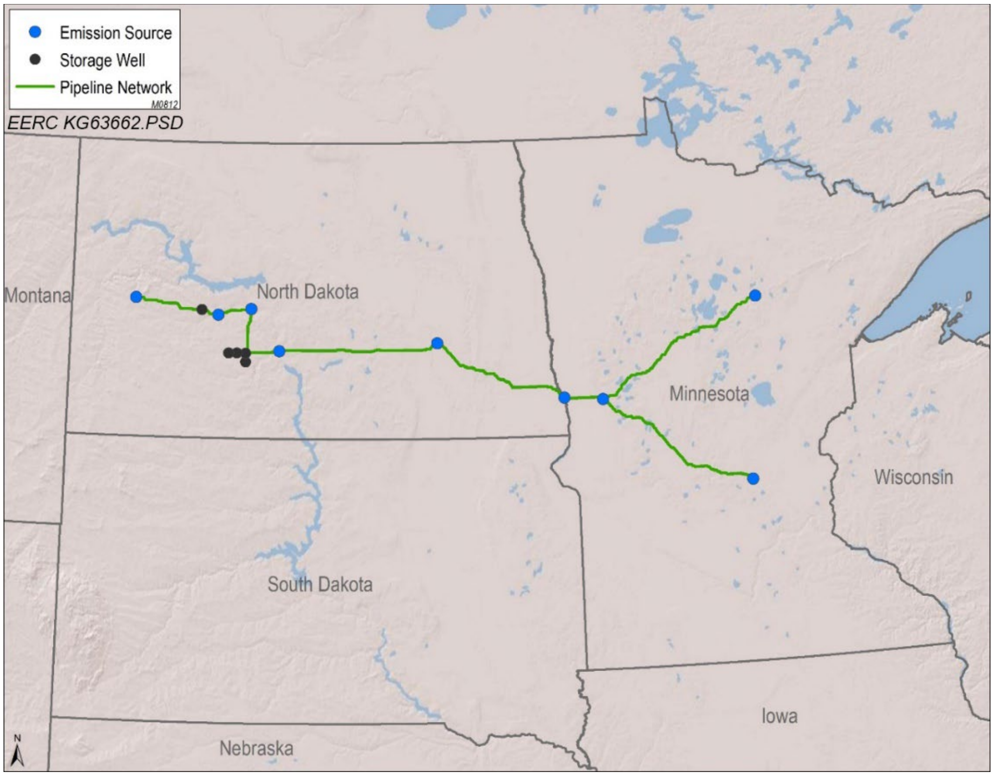

Figure 7. An optimized network layout targeting 51% of the total network CO_2 source emissions (25.75 million metric tons annually).

CAPTURE COST CALCULATIONS BASED ON IECM AND/OR EXISTING FEED STUDY

Cost of Carbon Capture System Retrofit Background

Estimating the cost of a carbon capture system for a source of CO_2 is challenging due to numerous factors. Factors that can affect the cost estimates are the source of the CO_2 emissions and operational parameters of the source; the availability of existing infrastructure and resources; governmental regulations and incentives; economic factors including labor, equipment deliveries and material costs; and finally, the type of capture technology used.

Therefore, to provide an accurate cost, it is essential to use a robust and thorough process when considering all relevant factors and uncertainties. This may involve working with experts in carbon capture technology, regulatory environments, and funding and incentives to ensure that the cost estimate is as accurate and reliable as possible. Costs of this level of detail tend to be completed in front-end engineering and design reviews.

In this type of study, it is more important that the differences in costs for different capture technology scenarios be assessed, rather than the absolute value of an expected project cost. Therefore, a broad and generalized approach was used. The tools most freely available to estimate the cost of carbon capture include eGRID and the IECM.

The eGRID is a comprehensive database that provides data on the environmental attributes of the electric power generation in the United States. The database is maintained by the U.S. Environmental Protection Agency (EPA) and serves as a primary source of information for policy makers, environmental analysts, and energy stakeholders. eGRID provides a comprehensive and up-to-date source of information on the emissions of various pollutants from power generation, including CO_2, sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg). Additionally, the database provides information on the type of fuel and energy sources used by power plants, their generation capacity, and the geographic location of the facilities.

The IECM is a free-to-use tool developed by Carnegie Mellon University (CMU) for analyzing the performance, emissions, and cost of fossil-fueled power plants. These models include process simulations that describe the behavior of the power plant's components, such as boilers, turbines, and scrubbers, as well as emissions models that predict the release of pollutants into the environment depending on the emission control operation used in the model. As an aside, the management and maintenance of the IECM has been moved from CMU to the University of Wyoming (UW) during the time of this report.

Cost of CCS Retrofit Approach

The approach to determine the cost of capture technology retrofit included gathering CO_2 emission sources and operational data from eGRID, using the data to simulate a base plant, and successively simulating the same plant with a carbon capture system. Then the resulting costs of the base plant and carbon capture plant can be compared to determine the increased costs of carbon capture in multiple ways.

IECM already has several base cases for pulverized coal power plants, including NETL Case 11 and Case 12 (Haslbeck and others, 2013), NETL Case B12A and B12B (James and others, 2019), and a "typical new plant" as defined by IECM. Case 11 is a greenfield 550 MWe net supercritical pulverized coal (SC PC) power plant with no carbon capture. Case 12 is a greenfield 550 MWe net SC PC plant with an amine capture unit with 90% CO_2 capture. Cases B12A and B12B are also based on a SC PC plant with a nominal net output of 650 MWe. Again, the only difference between the two plants is that Case B12B includes CO_2 capture while Case B12A does not.

These base cases were used as a starting point to input operational data from eGRID to estimate the costs associated with the base plant and carbon capture plant to estimate the cost of carbon capture retrofit throughout the PCOR Partnership region. There are several major assumptions in this retrofit analysis regarding plant design, plant performance, and financing that make this generalized approach. Full details on these assumptions regarding the base cases NETL Case 11 and NETL Case B12A can be found in Haslbeck and others (2013) and James and others (2019), respectively. The details regarding the assumptions of the typical new plant can be found in IECM.

The performance parameters of the base cases remained largely unchanged, including boiler efficiency and efficiency of postcombustion controls, water and solids management, and power requirements for auxiliary systems remain unchanged or were calculated by IECM. The carbon capture technology used to determine the cost of retrofit was amine-based carbon capture technology because it is the most advanced and commercially available technology for carbon capture today. All previous assumptions apply to this unit operation with the expectation that 90% of CO_2 is captured.

The financial parameters, such as construction time, book life, interest rates, cost factors, tax rates, and operating and maintenance costs for labor, consumables, etc., also remained unchanged from any of the base cases or were calculated by IECM. Finally, the financing and cost year was selected to be 2019 constant dollars unless otherwise noted, and the selected location was the Midwest region.

This cost of the capture system retrofit from the IECM model is only focused on the utility power industries. There are challenges of costing out non-power industries because of historically less research on capturing CO_2 from those industries, so cost associated with those industries will be estimated using equivalent technology and scale in terms of CO_2 production.

Cost of Carbon Capture System Data Preparation

The parameters that were selected and changed to help levelize differences in some plants included the fuel, whether it was lignite, subbituminous, or bituminous fuels, and the type of amine, whether it was FG+, Cansolv, or MEA. The primary parameters used from eGRID to determine the cost of the base plant and carbon capture retrofit plant include:

- Capacity factor (%).
- Plant input (MBtu/yr).
- Plant annual net generation (MWh).
- Plant heat rate, high heating value (HHV) (Btu/kWh).
- Carbon dioxide emissions (tons/yr).

Using these assumption and parameters, the goal is that the results from modeling and cost estimation can be replicated by any individual or organization, and personnel privy to detailed performance parameters and financial information can build more accurate cost estimates for individual plans.

One of the challenges faced with IECM is the parameters listed above from eGrid are not necessarily direct inputs to model an individual plant, which can make it a challenging, time-consuming, and iterative process to model a good representation of an individual plant, especially when looking at multiple scenarios. Therefore, the uncertainty analysis tools available in IECM were used to model plants of all different sizes, capacity factors, and efficiencies.

The data from IECM were used to create a random forest regression machine learning model to use direct inputs from eGrid and retrieve several outputs, including a few key performance parameters with cost of the base plant and carbon capture plant. Random forest regression is a supervised machine learning algorithm that uses an ensemble of decision trees to predict a continuous outcome. It works by building multiple decision trees and then combining their predictions to form a more accurate prediction. The model is trained using a training data set and the model is tuned using a test data set, both from IECM.

The purpose of the model is to provide a more efficient and accurate way to estimate the cost of multiple power plants within the PCOR region using IECM. The primary parameters that show the developed model is accurate are the mean squared error (MSE) and the coefficient of determination (R2). The MSE measures the average of the squares of the errors, which is the difference between the predicted values and the actual values. The R2 is a measure of how well the model fits the data, and it ranges from 0 to 1, with 1 being a perfect fit.

With the parameters that were selected and changed to help levelize differences in some plants including the fuel and type of amine and aggregating results from IECM's typical new plant, NETL Case 11 and 12, and NETL Case B12A and B12B into one data set, the regression model shows an MSE and R2 of 0.09 and 0.91, respectively, which indicate an extremely good fit. On an individualized case basis, as in the model is only created for NETL Case B12A and B12B, the MSE and R2 are 0.01 and 0.99, respectively, indicating a near-perfect fit to IECM.

Since the IECM model is not applicable to nonutility sources, another method for costing carbon capture plants on any source was developed based on capital cost scaling factors, as commonly applied in the chemical process industry (CPI). CO_2 emission sources in the PCOR Partnership region were compiled from EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT) and Environment Canada's greenhouse gas reporting program. This area, which comprises U.S. states Alaska, Iowa, Minnesota, Missouri, Montana, North Dakota, Nebraska, South Dakota, Wisconsin, and Wyoming along with the Canadian provinces of Alberta, British Columbia, Manitoba, and Saskatchewan, was then utilized to generate the CO_2 source list, including longitude and latitude data. Only CO_2 emission sources that were capable of supplying more than 250,000 metric tons of CO_2 per year were considered because of the escalating capital capture costs associated with smaller quantity sources and a need to reduce the complexity for pipeline network modeling. This has generated a list of 196 sources in the continental U.S. portion of the PCOR Partnership region that was used in the CO_2 pipeline and storage models.

Many times, in the chemical processing industry, equipment or a process is being scaled to a different size using similar process equipment to a known chemical process with a known capital cost. A capital costing process that has been commonly used in the chemical process industry for decades has been used to compare the capital cost of the known process or piece of capital equipment at the scale it was built at to the new process scale for the similar technology. More specifically, cost is a function of size raised to an exponent or scale factor.

The raised scale factor in Equation 1 accounts for the nonlinear relationship and introduces the concept of economies of scale where, as a facility becomes larger, the incremental cost is reduced for each additional unit of capacity. An exponent of 0 means the capital costs are independent of scale, while an exponent of 1 means the capital costs are linear with scale. A common rule of thumb is to use a scale factor 0.60 (Peters and Timmerhaus, 1980) when little data are available; however, scale factors for various types of chemical processing equipment have been determined over the years from historical cost data. These have been shown to range from 0.3 to greater than 1 for various types of chemical processing equipment. Previous literature has shown that coal-fired power plants have a scale factor around 0.72 while natural-gas-fired combined cycles are around 0.82. Thus the scale factor is a function of the particular process. There is no known scaling factor for postcombustion CO_2 capture plants at this point in time.

$$C2/C1 = (Q2/Q1)^x \qquad \text{[Eq. 1]}$$

Where:

C2 = capital cost of Process 2 with a known capacity of Q2
C1 = known capital cost of similar Process 1 with a capacity of Q1
Q2 = capacity of Process 2 to estimated
Q1 = known capacity of Process 1
X = scale factor for technology of Process 1 and 2

Ordinarily, the process is applied to processes or equipment in which the capital cost for the one scale is known from previously installed equipment after it has been corrected to a similar year of construction basis. Since there are very little capital cost data available for commercial-scale carbon capture plants and what is available is also considered highly confidential and probably would also be subject to higher costs associated with first-of-a-kind (FOAK) construction costs instead of n^{th} plant costs, the capital costs would have to be generated in a different manner.

The EERC also has access to a couple of prefeed studies that, when compared, generated a scale factor that was close enough to the generally accepted scale factor of 0.6 (sixth-tenth-factor rule). Therefore, that scale factor was applied to the list of sources spreadsheet to generate rough costs for the capture plant capital costs as a function of the CO_2 production capacity of the new source when compared to the capture capacity and projected capital cost of the baseline plant. In general, it is not recommended to utilize this equation outside a ten-fold range on the plant capacity. Also, this equation ideally should only be applied to very similar process technologies with similar process designs and materials of construction.

Transport Cost Model

Once the pipeline networks were determined for the given CCUS hub scenarios using SimCCS Gateway, the FECM/NETL CO_2 Transport Cost Model (2022) (Transport Cost Model) was used to estimate the cost of each pipeline segment within the various hub scenarios and the cost for each segment totaled to determine the overall cost of the project. The inputs used in the model are as follows:

- Equation used for capital cost of natural gas pipelines – Parker
- Region of United States or Canada – Central (Cen)
- Volume – million metric tons per year for each of the pipeline segments
- Temperature of the CO_2 stream – 65°F
- Pipeline pressures

- Inlet pressure – 2000 psig, no additional pressurization required at inlet to pipeline.
- Outlet pressure – varied by segment because of flow and distance.
  - Pipeline segments - a minimum of 1500 psig was used for determining when the installation of a pump system would be required. Cost of the pump system and the operating costs reflect repressuring the CO_2 stream to 2000 psig.
  - Sink locations – a 100 psig pressure drop between sinks in a linear manner was used to determine the line sizing required for the sections of pipelines. This was to minimize the number of pumps required.
  - No additional pressurization of the CO_2 stream above the delivered pressure was required at the sinks.

- Elevation – net change in elevation of the segment from inlet to outlet

- All costs reflect the 2011 cost value as provided from the Transport Cost Model. No changes to the various indices used in the model were made to update the cost estimates to more current values.

As indicated by Warmack and others (2022), the cost of CO_2 pipelines varies because of flow, length, operating pressure, inlet temperature, elevation changes, etc. Because of the number of different types of CO_2 sources within this report's scenarios and resulting capture method, the pipeline scenarios were simplified using the properties outlined above.

Since this evaluation was strictly looking at the cost of the pipeline infrastructure required for each scenario, only the outside diameter (OD), inside diameter (ID), pipeline cost, and operational expense were used from the Transport Cost Model. The pipeline costs do not include any power upgrades or installation of new power to the pump sites, which could be considerable if power is not near the vicinity of the pump sites.

For each pipeline segment, a section of pipe transporting CO_2 volumes between sources, junctions, or sinks, a base design reflected the calculated OD and associated costs to deliver the flow at the indicated pressure drop without the aid of pump stations installed on the pipe segment (pumps would be required to repressurize the CO_2 stream back to 2000 psig if the pressure reached 1500 psig at the end of the segment). To determine the effect of adding pump stations within the pipe segments to the overall cost of the system, additional runs were made with up to seven pump stations along the pipe segments. The option selected for each segment with pumps reflects a 10-year total cost for each pipeline segment, which includes the cost to construct the pipeline segments and the operational cost of the pipeline. The operational expense for the pipeline includes the operational cost of installed pumps (along the pipeline segments and to repressure the CO_2 stream once the pressure reached 1500 psig) and the operational cost of the pipeline itself. In addition, an overall cost of the project in terms of cost per tonne, average pipeline OD, and average pipeline cost in dollars per inch-mile of line are presented for the base case and with pump installations considered.

A summary of the pipeline segments and associated costs is provided for each scenario selected, which can be found in Appendix A.

EVALUATION OF CCUS HUB SCENARIOS

SimCCS Gateway was used to evaluate multiple regions and different CCUS hub scenarios. The total number of emission sources in the evaluated data set was 196. This number was determined by eliminating emission sources where capture costs were significantly higher on a dollar per metric ton rate and emission sources that are already known to be part of a CCUS project (e.g., ethanol facilities as part of the announced Summit Carbon Solutions project). It is important to note that the evaluations performed ignore significant real-world factors such as regulatory environment, permitting requirements, and other business- or investment-related decisions. These simulated scenarios were scoping in nature and do not reflect all possible considerations for projects such as these.

Because of memory limit errors that were encountered, it was necessary to try to reduce the complexity of the modeled scenarios to work within the available SimCCS Gateway's computational resources. This evaluation is concentrated only on dedicated saline formation storage and ignores possible EOR applications. The PCOR Partnership region was also broken up into multiple areas of interest to generate hypothetical CCUS hubs. The following scenario represents sources in Iowa with greater than 250,000 metric tons annual CO_2 emission and possible storage locations in Illinois and North Dakota, as both states have sufficient capacity to store CO_2. As mentioned previously, the facilities that are part of the Summit Carbon Solutions and Heartland Greenway are not included and facilities less than 250,000 metric tons were removed due to capture costs and to reduce model complexity. Figure 8 shows a candidate pipeline system for evaluation generated by SimCCS Gateway. The program was allowed to use internal algorithms, cost surface maps, and the generated capture cost data to identify the lowest cost capture and storage scenarios for 33%, 66%, and 90% CO_2 capture. Table A-6 in the appendix lists information on the sources included in this scenario. The costs used ignore any potential tax credits or other program-based cost offsets that may be available and assume an annual capital recovery rate of 10%.

Figure 9 shows the 33% capture hub scenario. As has been consistent with other scenarios, the largest sources with the lowest CO_2 capital and capture costs per metric ton are identified as the best capture targets. In this 33% capture scenario, 16 million metric tons of CO_2 are captured annually, and SimCCS Gateway identified the lowest-cost sink location to be Illinois instead of North Dakota. Illinois was identified as the lowest-cost sink location likely because of proximity and having in excess of 1400-ft lower elevation than sites in North Dakota. To limit complexity of the model, no sources were included for evaluation in the vicinity of the pipeline headed to North Dakota storage sites. Adding sources along this artery would significantly reduce the transport costs per tonne CO_2 and would positively impact the economic viability.

For this 33% capture and the following scenarios, the blue dots reflect the source of the CO_2 streams, with the black dots indicating the simulated storage well. For this example, SimCCS Gateway identified the capture, transport, and storage costs to be $45.37, $2.19, and $6.60 per metric ton of CO_2, respectively, for a total of $54.15/t$CO_2$. In comparison, using the Transport Cost Model, the transport costs are $7.69 per metric ton without pumps on the segments and $6.45 per metric ton with pumps installed on the pipe segments. Pump systems required at specific points along the pipeline system are included within each cost.

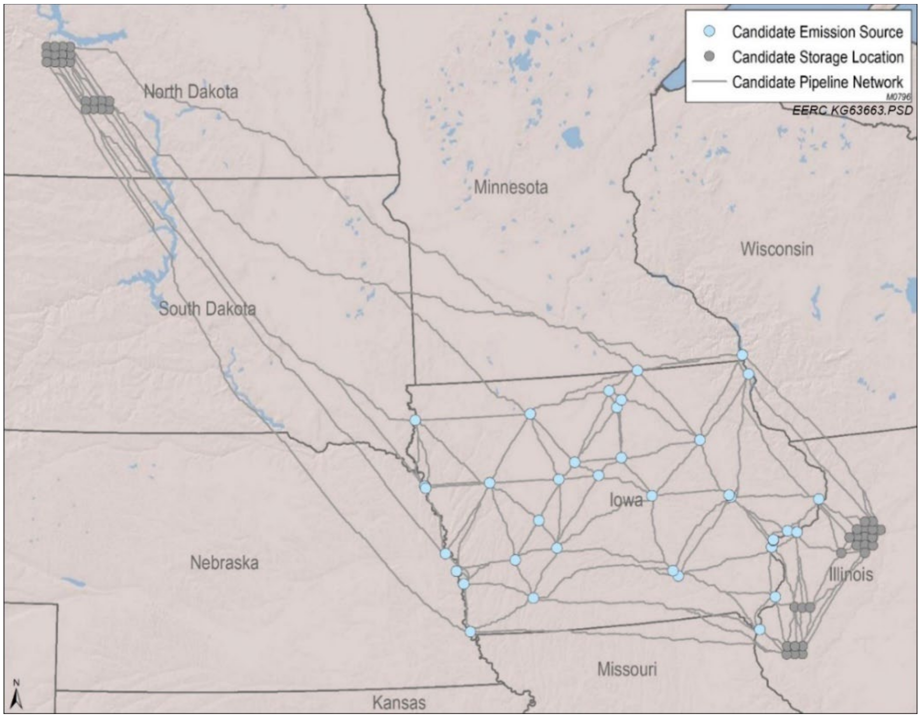

Figure 8. Candidate network showing optimal routes for pipeline connections between candidate storage wells (gray dots) and sources (light blue dots) in Illinois or North Dakota.

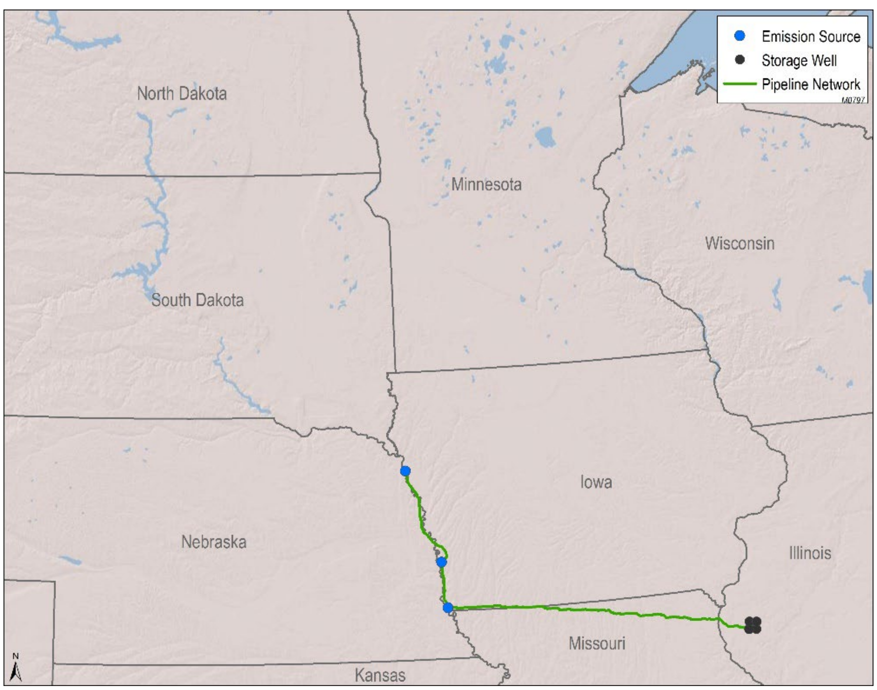

Figure 9. A SimCCS Gateway hub network layout targeting 33% of the total network CO_2 emission source capacity (16 million metric tons of 48 million metric tons annually).

Figure 10 shows the scenario for 66% capture from the Iowa sources for a total of 32 million metric tons annually. This scenario shifts the artery of the network further north and targets larger storage resources further north in Illinois. Lower-emitting CO_2 sources have higher costs per metric ton of captured CO_2. As more of these lower-emitting sources are included, the aggregated CO_2 capture cost increases for the network, though the pipeline transport and storage costs decrease as flows increase for greater capital utilization efficiency. In this scenario, SimCCS Gateway identified the capture, transport, and storage costs to be \$51.78, \$1.73, and \$6.42 per metric ton of CO_2, respectively, for a total of \$59.93/tCO_2. In comparison, using the Transport Cost Model, transport costs are \$6.25/tCO_2 without additional pumps installed on the pipeline segments and \$5.70/tCO_2 with additional pumps installed.

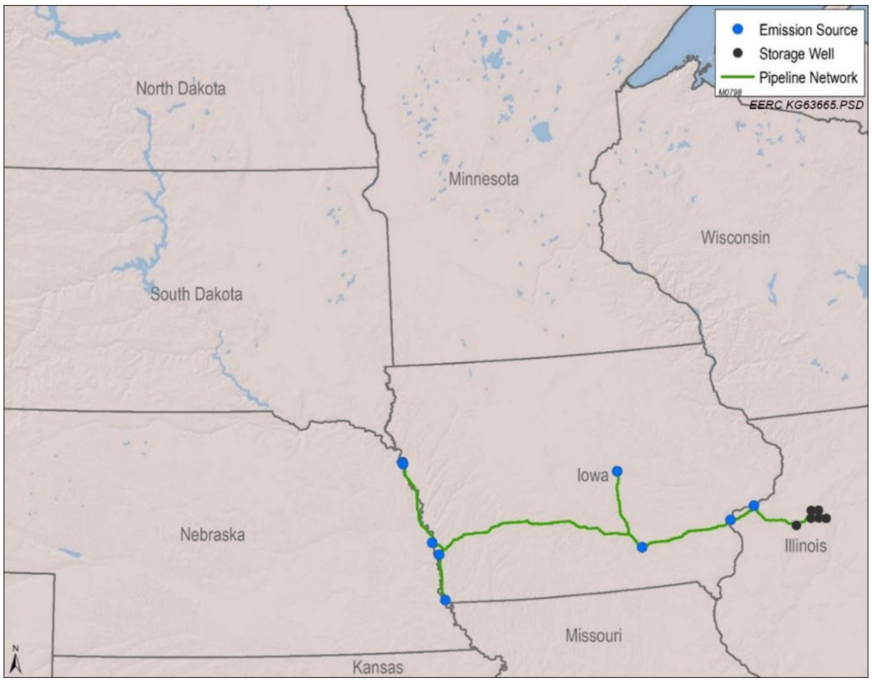

Figure 10. A SimCCS Gateway hub network layout targeting 66% of the total network CO_2 source emissions (32 million metric tons annually).

The most complex capture scenario modeled in this region is shown in Figure 11. This represents 90% capture on all sources over 250,000 metric tons or 43 million metric tons annually. This network maintains the same main artery line that runs south of Des Moines over to northwestern Illinois as the 66% capture scenario but adds a significant number of smaller sources to achieve 90% capture. In this scenario, the addition of a significant number of smaller sources drives the capture costs higher, and since these are located further from the main line, the transport costs increase slightly, though the storage costs are driven further down. SimCCS Gateway identified the capture, transport, and storage costs to be \$63.81, \$1.81, and \$6.38 per metric ton of CO_2, respectively, for a total of \$72.00/tCO_2. In comparison, using the Transport Cost Model, transport costs are \$6.15/tCO_2 without additional pumps installed on the pipeline segments and \$5.85/tCO_2 with additional pumps installed. Evaluated data from additional scenarios are shown in Appendix A.

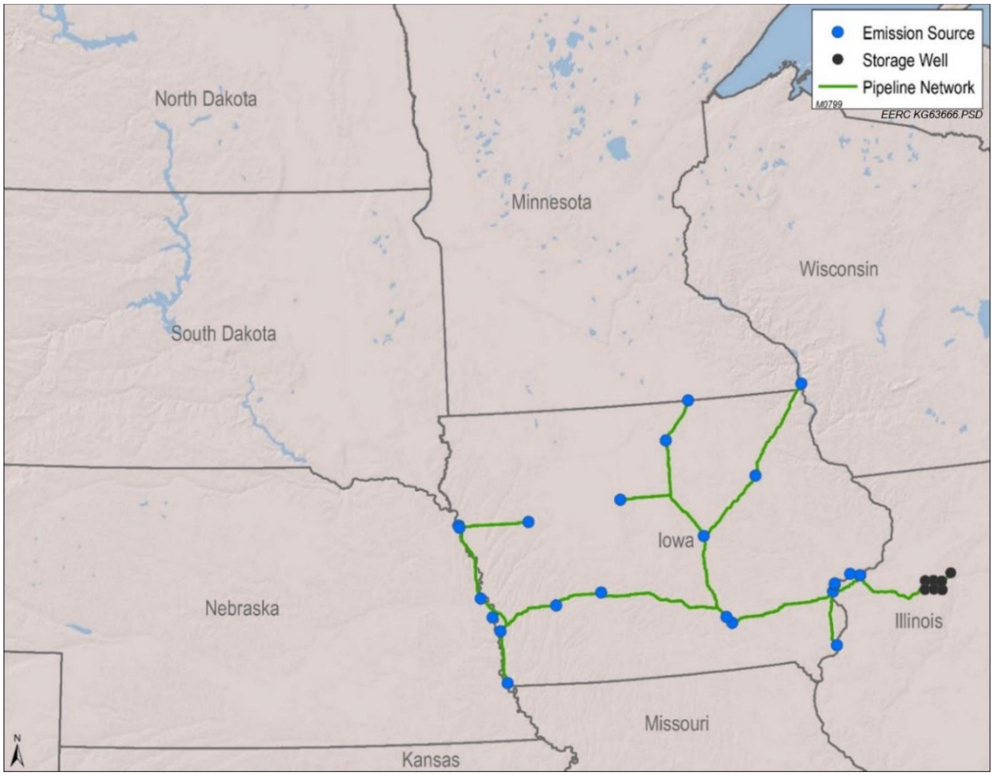

Figure 11. A SimCCS Gateway hub network layout targeting 90% of the total network CO_2 source emissions (43 million metric tons annually).

DISCUSSION

This report simulated hypothetical CCUS hubs for CO_2 emission sources that are not colocated with known geologic storage resources. SimCCS Gateway was used to simulate a variety of scenarios in the PCOR Partnership region to evaluate potential CCUS hub development. Some considerations of CCUS hub development are well understood, such as capture of CO_2 at industrial facilities will represent on the order of 75%–85% of the total CCUS project costs. Further, as pipeline networks extend for greater distances, the economics can prove more challenging to incorporate smaller facilities that have a lesser volume of CO_2 for transport and storage. Pipeline costs will also increase when moving toward higher elevations, as additional pumps are required to combat pressure losses from the elevation change. Therefore, sufficient volumes should be transported through the system to have favorable economics on a cost per volume basis.

When evaluating the performance of the SimCCS Gateway simulated scenarios, the model did provide optimal hub networks that made logical sense. As capture scenarios transitioned from 33% to 66% capture, emission sources near the main trunkline/pipeline were added to the system with minimal cost increases. When expanding out to 90% capture scenarios, the economics were not as favorable as the added costs of capturing the smaller, geographically spread-out network and drove up transportation costs on a dollars/tonne basis. The software did make interesting decisions on some scenario network decisions. For example, in taking CO_2 from Missouri (Appendix A, Figures A-7 and A-8), the pipeline network bypassed storage options in Nebraska and moved the CO_2 to Wyoming, opting for more favorable storage costs/conditions in Wyoming's storage targets. Further understanding of the cost surface and associated algorithms would be necessary to understand the selected route in this study. The SimCCS Gateway software did have limitations in the level of complexity that could be analyzed for given scenarios. The limitations appeared to be related to memory capabilities of the Gateway's computational resources, but these limitations were avoided by focusing the simulated scenarios on smaller areas of interest.

The Transport Cost Model was performed on the pipeline network for each CCUS hub scenario. The improved case results, summarized in Table 1, show the expected costs (capital expenditure [CAPEX] and operating expenses [OPEX] for the overall pipeline system) associated with the different scenarios on a cost/tonne basis. Some observations from this analysis include:

- Minimizing the length of the pipeline system provides the lowest transport cost.
- Increasing the OPEX of the pipeline with the addition of pumps did not translate with an equal increase in the overall cost in dollars/tonne for the system. This is becasue the addition of pumps tends to decrease the size of the pipelines, thereby reducing the overall CAPEX of the system.
- Increasing the amount of CO_2 captured results in the expansion of the pipeline system. However, the expansion may not overly burden the transport cost for the system.

Table 1. Summary of Transport Cost Model for Each Scenario (improved case only)

			Improved case (with pumps on pipeline segments) [1]						
Scenario	Total Rate MMt/yr	Total PL Length Miles	PL OD Inches	PL CapEx MM$	PL OpEx Cost, MM$	CapEx $/tonne	OpEx $/tonne	Total [2] $/tonne	Total [2] $/MCF
MO_IL_KS_22Mt	22.0	324.2	4" - 30"	$614.8	$11.48	$2.79	$0.52	$3.32	$0.18
MO_IL-KS_61Mt	58.5	977.9	8" - 42"	$1,780.3	$42.73	$3.04	$0.73	$3.77	$0.20
IA_ND_IL_16 Mt	16.0	435.1	8" - 30"	$905.7	$12.62	$5.66	$0.79	$6.45	$0.34
IA_ND_IL_32Mt	32.0	599.5	6" - 36"	$1,517.3	$30.81	$4.74	$0.96	$5.70	$0.30
IA_ND_IL_42 Mt	43.0	1061.2	4" - 42"	$1,979.7	$53.73	$4.60	$1.25	$5.85	$0.31
MO-NE-WY-2 Source	21.9	851.6	16" - 36"	$2,789.2	$37.98	$12.74	$1.73	$14.47	$0.76
ND_MN_16.8 Mt	16.8	580.9	12" - 30"	$1,115.5	$27.66	$6.63	$1.64	$8.27	$0.44
ND_MN_MED 25.1 Mt	25.1	687.1	6" - 30"	$1,549.8	$36.10	$6.18	$1.44	$7.62	$0.40

1. Improved case includes cost of additional pump stations above those included in the base case.
2. Cost per tonne and MCF reflect a 10 year project life.

Overall, the simulated hypothetical CCUS hub networks provide some useful initial feedback for potential project developers. The scenarios lay out a number of different options for different portions of the PCOR Partnership region. Cost information from the scenarios (Table 2) indicate that these hypothetical CCUS hubs would have favorable economics on a dollars/tonne

Table 2. Summary of Costs from SimCCS

			Pipeline Summary		SimCCS Gateway Results			
	Rate	Total PL Length	Range in Ods	PL Cost	Plant Cost	Transport Cost	Storage Cost	Total
Scenario	MMt/yr	Miles	Inches	$/avg inch -mile	$/tonne	$/tonne	$/tonne	$/tonne
MO_IL_KS_22Mt	22.0	324.2	4" - 30"	$89,007	$42.05	$1.18	$6.41	$49.64
MO_IL-KS_61Mt	58.5	977.9	8" - 42"	$89,100	$48.29	$1.29	$6.47	$56.05
IA_ND_IL_16 Mt	16.0	435.1	8" - 30"	$89,789	$45.37	$2.19	$6.60	$54.16
IA_ND_IL_32Mt	32.0	599.5	6" - 36"	$95,451	$51.78	$1.73	$6.42	$59.93
IA_ND_IL_42 Mt	43.0	1061.2	4" - 42"	$94,091	$63.81	$1.81	$6.38	$72.00
MO-NE-WY-2 Source	21.9	851.6	16" - 36"	$97,036	$40.29	$3.73	$6.97	$50.99
ND_MN_16.8 Mt	16.8	580.9	12" - 30"	$85,719	$44.43	$3.17	$7.63	$55.23
ND_MN_MED 25.1 Mt	25.1	687.1	6" - 30"	$113,046	$52.50	$2.23	$7.52	$62.25

basis if the project participants apply and qualify for IRS' Section 45Q tax credits, which are currently at $85/ton for dedicated saline storage. However, as demonstrated by the three scenarios for the Iowa–North Dakota–Illinois grouping, as the total scenario volume increases (16 vs. 32 vs. 43), costs of the network capture cost for the CO_2 volumes (on a per Mt basis over 10 years) increases. This is depicted in Table 3, where the initial sources for the 16-Mt/yr scenario were some of the lowest costs per Mt. For the other two scenarios, higher-cost facilities were added to make up the volumes for the 32- and 43-Mt/yr requirement, resulting in increased pipeline infrastructure.

The SimCCS Gateway software selected emission sources and routed pipelines in a manner that would be useful for initial project planning. With that said, progressing development of CCUS hubs will require detailed engineering analysis of the capture, transport, and storage facilities that incorporate site-specific information (i.e., capture costs based on specific facilities) for proper project planning. Interest and cooperation of individual companies of the capture facilities will also drive the development of the CCUS hub. These companies, along with potential third-party owners of the pipelines, will factor in specific business decisions that will also impact decisions related to hub development. Regulatory environments in the jurisdiction(s) where the project is potentially located will play a role, as considerations of Class VI primacy, pore space law, and long-term liability can significantly alter the location that a CCUS hub project might decide to store the captured CO_2. Finally, transportation pipelines and actual storage well locations will be driven by numerous factors, such as landowner support for the given project.

Table 3. Summary of Cost Drivers for the IA_ND_IL 16-, 32-, and 43-Mt/yr Scenarios

Cost Fix ($M)	Cap Max ($MtCO_2$/yr)	NAME	Source Type	16 Mt/yr	32 Mt/yr	43 Mt/yr	Cost Fix/Mt (10 years)
$1,147.8	7.97	Walter Scott Jr. Energy Center	Electric Generation	Yes	Yes	Yes	$28.4
$1,040.2	6.77	Nebraska City Station	Electric Generation	Yes	Yes	Yes	$30.2
$764.5	4.05	Ottumwa	Electric Generation		Yes	Yes	$37.3
$675.3	3.29	Louisa	Electric Generation		Yes	Yes	$41.1
$563.0	2.43	CF Industries Nitrogen, LLC-Port Neal Nitrogen Complex	Ammonia Manufacturing		Yes	Yes	$48.0
$517.7	2.11	North Omaha Station	Electric Generation		Yes	Yes	$51.9
$455.6	1.71	George Neal North	Electric Generation		Yes	Yes	$58.8
$420.8	1.50	Sutherland	Electric Generation		Yes	Yes	$63.9
$413.0	1.45	George Neal South	Electric Generation	Yes	Yes	Yes	$65.2
$377.1	1.25	Genoa	Electric Generation			Yes	$72.2
$371.2	1.22	Burlington (IA)	Electric Generation			Yes	$73.5
$365.8	1.19	Cargill Corn Milling North America	Ethanol Production			Yes	$74.7
$360.7	1.16	Muscatine	Electric Generation			Yes	$76.0
$339.9	1.05	Emery Station	Electric Generation			Yes	$81.6
$285.6	0.78	Davenport Plant	Cement Production		Yes	Yes	$102.3
$252.8	0.64	Elite Octane	Ethanol Production			Yes	$121.8
$239.4	0.58	Koch Fertilizer Ft. Dodge, LLC	Ammonia Manufacturing			Yes	$132.3
$235.0	0.57	Flint Hills Resources Arthur LLC	Ethanol Production			Yes	$136.1
$231.6	0.55	Flint Hills Resources LLC - Fairbank Ethanol Plant	Ethanol Production			Yes	$139.3
$230.1	0.55	Flint Hills Resources Menlo, LLC	Ethanol Production			Yes	$140.6
$221.7	0.51	Absolute Energy LLC	Ethanol Production			Yes	$149.3
$217.4	0.50	Cargill Inc - Eddyville	Ethanol Production			Yes	$154.2
$214.4	0.49	Lansing	Electric Generation				$157.8
$214.3	0.49	Prairie Creek	Electric Generation				$157.8
$204.5	0.45	Flint Hills Resources Iowa Falls, LLC	Ethanol Production				$170.7
$199.3	0.43	Grain Processing Corp	Ethanol Production			Yes	$178.5
$194.3	0.41	Roquette America Inc	Food Processing				$186.6
$192.1	0.41	Lehigh Cement Co LLC	Cement Production				$190.3
$187.5	0.39	Equistar Chemicals LP	Other Chemicals				$198.8
$184.3	0.38	Ssab Iowa Inc.	Iron and Steel Production			Yes	$205.1
$180.1	0.36	Linwood Mining & Minerals Corporation	Lime Manufacturing			Yes	$213.9
$178.7	0.36	Pinnacle Ethanol LLC D/B/A Poet Biorefining - Corning	Ethanol Production				$217.0
$173.3	0.34	Poet Biorefining	Ethanol Production				$229.9
$170.3	0.33	Poet Biorefining - Gowrie, LLC	Ethanol Production				$237.7
$167.1	0.32	Poet Biorefining - Hanlontown LLC	Ethanol Production				$246.4
$163.9	0.31	Poet Biorefining - Hudson (Sioux River Ethanol)	Ethanol Production				$256.0
$156.5	0.29	Voyager Ethanol LLC-Poet Biorefining-Emmetsburg	Ethanol Production				$280.4
$149.5	0.27	Poet Biorefining-Coon Rapids	Ethanol Production				$307.8
$143.9	0.25	Ingredion Incorporated	Ethanol Production				$333.4

CONCLUSION

CCUS projects consist of the CO_2 capture facilities, transportation of the CO_2, and the geologic storage location. In those cases where CO_2 capture facilities are at or near a dedicated or associated storage site, the individual facility will often elect to conduct its own capture and storage operation. However, if the CO_2 must be transported over a greater distance, CCUS project hubs are a likely scenario where a group of capture facilities will create a network of transport pipelines to move CO_2 to a final storage destination.

The simulated CCUS hubs from SimCCS Gateway present an initial evaluation that provides insight on possible capture, transport, and storage volumes, associated costs, and potential optimal pipeline routing. The hub scenarios presented provide a screening of emission sources that could be joined for an optimal hub network. The scenarios evaluated using SimCCS Gateway were arbitrarily restricted in this evaluation because of computational system limitations that were encountered when the modeled scenarios became too complex. For this reason, the simulated hubs were analyzed in smaller regions. Leveraging these smaller regions were effective for weighing different capture and storage options. As such, any development of CCUS hubs will require a detailed engineering and geologic analysis that offers site-specific information (i.e., capture costs for specific facilities and storage potential of prospective sites) for proper project planning.

Commercial CCUS deployments in the PCOR Partnership region will vary by geographic location and depend upon the specific business cases and/or economics tied to any given potential capture facility. The potential for CCUS hub development exists in the region, as evidenced by existing and developing projects, and the results of this report reaffirm this potential. Future CCUS hub developers will balance the volumes of CO_2 captured and stored and the associated revenue generated (e.g., 45Q, Low Carbon Fuel Standard) versus the overall project costs (e.g., pipelines, pumps, capture systems, and number of sites).

As interest in CCUS projects continues to grow in the PCOR Partnership region, CCUS hub development will be important for maximizing the available CO_2 storage resource. Additional optimization and savings in costs could be investigated to understand how coordination among CCUS hubs could benefit multiple projects. Examples may include overlapping pipeline or other rights-of-way, optimizing available storage space, or sharing infrastructure or utilities (e.g., maximizing/coordinating electrical generation for project operations).

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APPENDIX A

PIPELINE SEGMENTS AND ASSOCIATED COSTS

PIPELINE SEGMENTS AND ASSOCIATED COSTS

The candidate network shown in Figure A-1 comprises 27 emission sources and 50 possible storage well locations. The total volume of the candidate sources is 67.3 million metric tons. Data for the sources included in the network are shown in Table A-1. This scenario was setup to compare options for storing CO_2 in Kansas vs. Illinois and to identify optimized capture networks at 22 and 61 million metric tons annually for comparison.

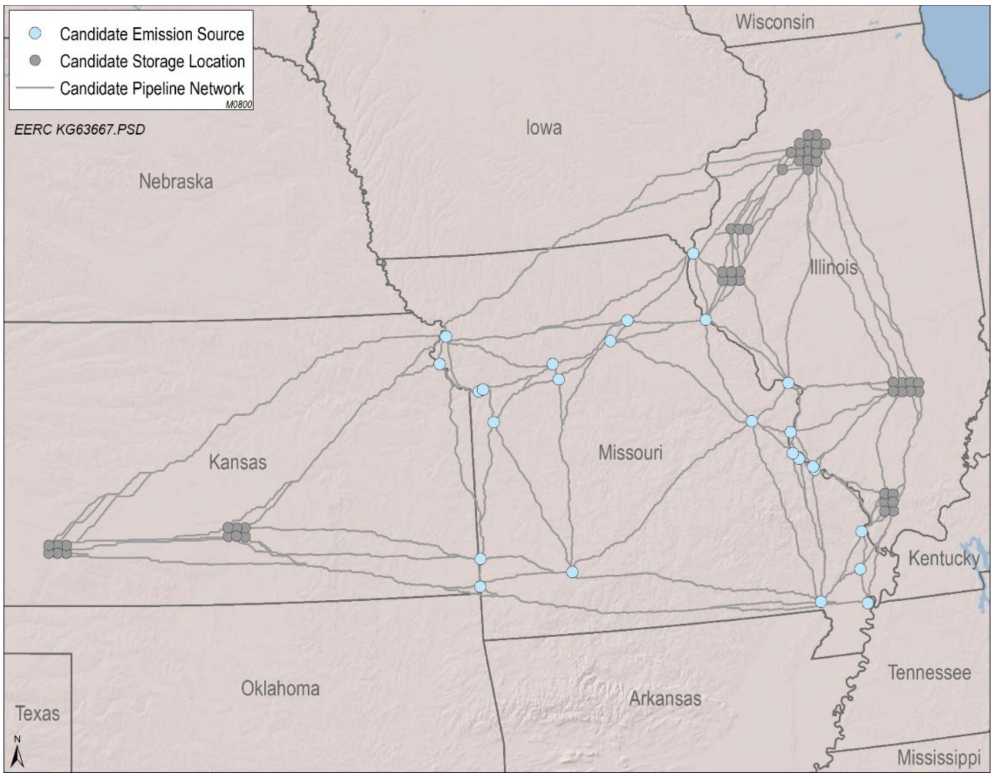

Figure A-1. Candidate network showing optimal routes for pipeline connections between Missouri CO_2 sources greater than 250,000 metric tons annual production and candidate storage well locations in Kansas or Illinois.

Table A-1. Source Data from the Missouri Candidate Network

ID	capMax (MtCO2/y)	LON	LAT	NAME	Source Type
2256	0.413	-91.398	40.388	Roquette America Inc.	Food Processing
3924	0.898	-94.591	37.360	Asbury	Electric Generating
3934	0.740	-94.417	39.144	Central Plains Cement Company, LLC	Cement Production
3940	0.767	-91.314	39.679	Continental Cement Company, LLC	Cement Production
3942	0.955	-94.301	38.793	Dogwood Energy Facility	Electric Generating
3954	2.798	-94.478	39.131	Hawthorn Generating Station	Electric Generating
3955	2.873	-90.258	38.110	Holcim (US) Inc. Ste Genevieve Plant	Cement Production
3957	7.500	-94.980	39.447	Iatan Generating Station	Electric Generating
3962	1.741	-93.389	37.152	John Twitty	Electric Generating
3963	14.069	-90.836	38.558	Labadie	Electric Generating
3964	0.289	-94.877	39.725	Lake Road Generating Station	Electric Generating
3966	0.814	-90.080	38.009	Lhoist North America	Lime Manufacturing
3967	0.742	-89.539	37.268	Lone Star Industries	Cement Production
3968	0.293	-89.565	36.511	Magnitude 7 Metals, LLC	Aluminum Production
3971	0.567	-90.336	38.402	Meramec	Electric Generating
3973	0.259	-93.386	39.197	Mid-Missouri Energy, LLC	Ethanol Production
3974	2.607	-90.068	37.974	Mississippi Lime Company	Lime Manufacturing
3978	6.191	-89.562	36.515	New Madrid Power Plant	Electric Generating
3986	0.696	-92.385	39.748	Poet Biorefining-Macon	Ethanol Production
3989	1.685	-90.337	38.180	River Cement Company Dba Buzzi Unicem USA	Cement Production
3991	5.266	-90.263	38.131	Rush Island	Electric Generating
3993	0.267	-93.449	39.363	Show Me Ethanol	Ethanol Production
3995	1.549	-89.621	36.879	Sikeston	Electric Generating
3997	3.998	-90.292	38.916	Sioux	Electric Generating
4004	0.415	-90.178	36.585	St. Francis Power Plant	Electric Generating
4005	1.066	-94.614	37.066	State Line (MO)	Electric Generating
4007	7.850	-92.639	39.553	Thomas Hill Energy Center	Electric Generating

Figure A-2 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 22 million tonnes/year over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified three sources to generate the target 22 million metric tons of CO_2 annually, with those sources storing into four wells. Table A-2 lists the source and storage data for Figure A-2. Table A-3 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without additional pumps installed on the pipeline segments. SimCCS Gateway produced resulting costs of \$42.05, \$1.18, and \$6.41 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of \$49.64/tonne CO_2. The FE/NETL CO_2 Transport Cost Model provided cost of \$3.90 per tonne without pumps on the pipeline segments and \$3.32 per tonne with additional pumps installed.

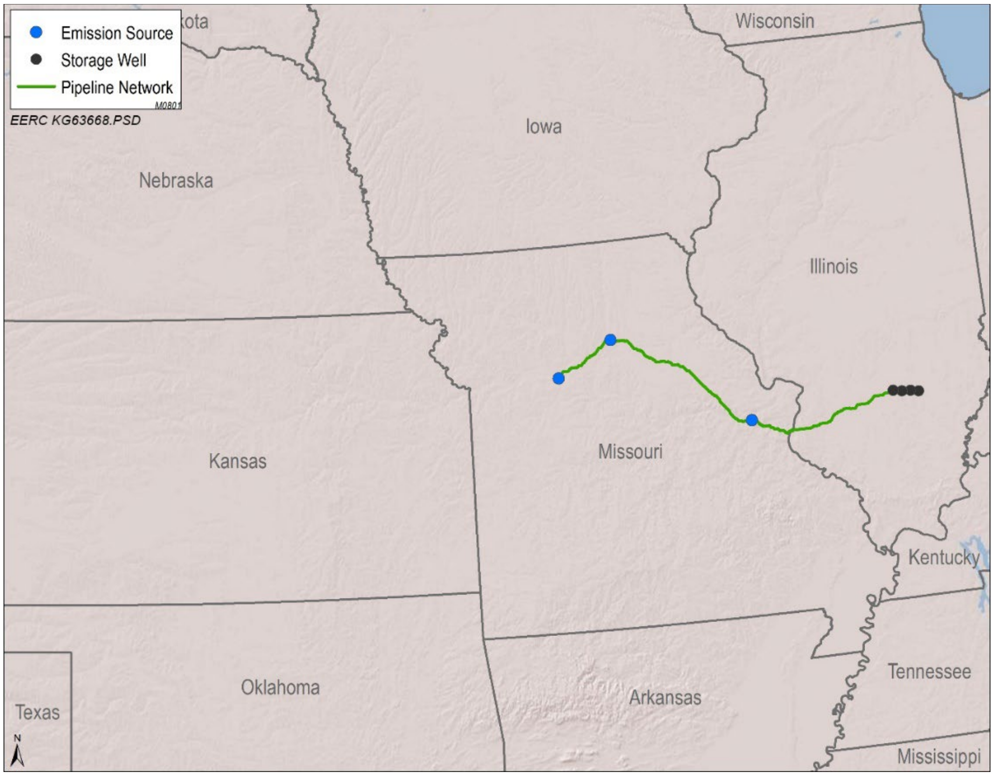

Figure A-2. Source, storage, and pipeline network for MO_IL_KS_22-Mt scenario.

Table A-2. Listing of Sources and Sinks for MO_IL_KS_22-Mt Scenario

Start	Name	Longitude	Lattitude	Flow (Mt/yr)
3973	Mid-Missouri Energy LLC	-93.386389	39.197222	0.26
4007	Thomas Hill Energy Center	-92.6392	39.5531	7.67
3963	Labadie	-90.8361	38.5583	14.07
103072	Sink 20	-88.897279	38.6926533	6.0
103130	Sink 17	-88.78317	38.6806275	6.0
103187	Sink 16	-88.669095	38.6684795	6.0
103243	Sink 15	-88.555053	38.6562095	4.0

Table A-3. Summary of Pipeline Segments for MO_IL_KS_22-Mt Scenario

MO_IL_KS_22Mt

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Segment	Start	End	Elevations Start	Elevations End	Flow Mt/yr	Flow MMSCFD	Pressures Inlet	Pressures Outlet	Length kM	Length Miles	Cost of Pump Stations for System Capital	Cost of Pump Stations for System Operating	Base Case - Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Refined Case - Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	3793	4007	699	653	0.26	13.4	2,000	1,500	83.3	51.8	$0.1	$0.0	0	6	4.7	$33.7	$108,367	$0.9	$43.44	2	4	3.8	$30.5	$147,405	$1.0	$40.9
2	4007	3963	653	493	7.93	411.8	2,000	1,500	213.7	132.8	$1.8	$0.9	0	24	20.4	$270.4	$84,823	$2.3	$303.8	1	20	18.0	$211.8	$79,721	$2.3	$245.1
3	3963	Sink 20	493	563	22.00	1,142.2	2,000	1,500	192.9	119.8	$4.9	$2.4	0	36	30.6	$420.1	$97,384	$2.1	$469.4	1	30	26.6	$329.7	$91,707	$4.4	$402.5
4	Sink 20	Sink 17	563	524	16.00	830.7	2,000	1,900	11.0	6.9			0	24	20.0	$16.0	$97,560	$0.2	$17.8	0	24	20.0	$16.0	$97,560	$0.2	$17.8
5	Sink 17	Sink 16	524	532	10.00	519.2	1,900	1,800	10.6	6.6			0	20	17.1	$12.4	$94,379	$0.2	$14.1	0	20	17.1	$12.4	$94,379	$0.2	$14.1
6	Sink 4	Sink 15	532	489	4.00	207.7	1,800	1,700	10.3	6.4			0	12	11.6	$7.6	$98,772	$0.2	$9.2	0	12	11.6	$7.6	$98,772	$0.2	$9.2
	Totals				**22.0**			**3**		**324.2**	**$6.8**	**$3.2**				**$760.2**		**$5.8**	**$857.6**	4			**$608.0**		**$8.2**	**$729.7**

Number of years for project **10**

Unit Cost (Based on 2011 Costs in Model) = **$3.90** **per tonne CO2**

Average Pipeline OD = **25.2** **inches**

Average Pipeline Cost = **$92,877** **per inch-mile**

Unit Cost (Based on 2011 Costs in Model) = **$3.32** **per tonne CO2**

Average Pipeline OD = **21.1** **inches**

Average Pipeline Cost = **$89,007** **per inch-mile**

Figure A-3 shows the network identified by SimCCS Gateway for capturing, transporting, and sequestering 61 million tonnes/year over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified 15 sources to generate the target 61 million metric tons of CO_2 annually sinking into 12 wells. Table A-4 lists the source and sink data for Figure A-3. Table A-5 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without additional pumps installed on the pipeline segments. SimCCS Gateway produced resulting costs of $48.29, $1.29, and $6.47 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of $56.05/ton CO_2. Increasing from the 22-Mt/yr and 61-Mt/yr capture scenarios results in a 14.8% increase in capture costs, 9.3% increase in transportation costs, and 0.9% increase in storage costs, for a total cost increase of $6.41. The increase in the pipeline (PL) transport cost for the 61-MMt/yr case is directly attributable to the greater length of line required and the associated cost of the pipeline system for the increased capture rate.

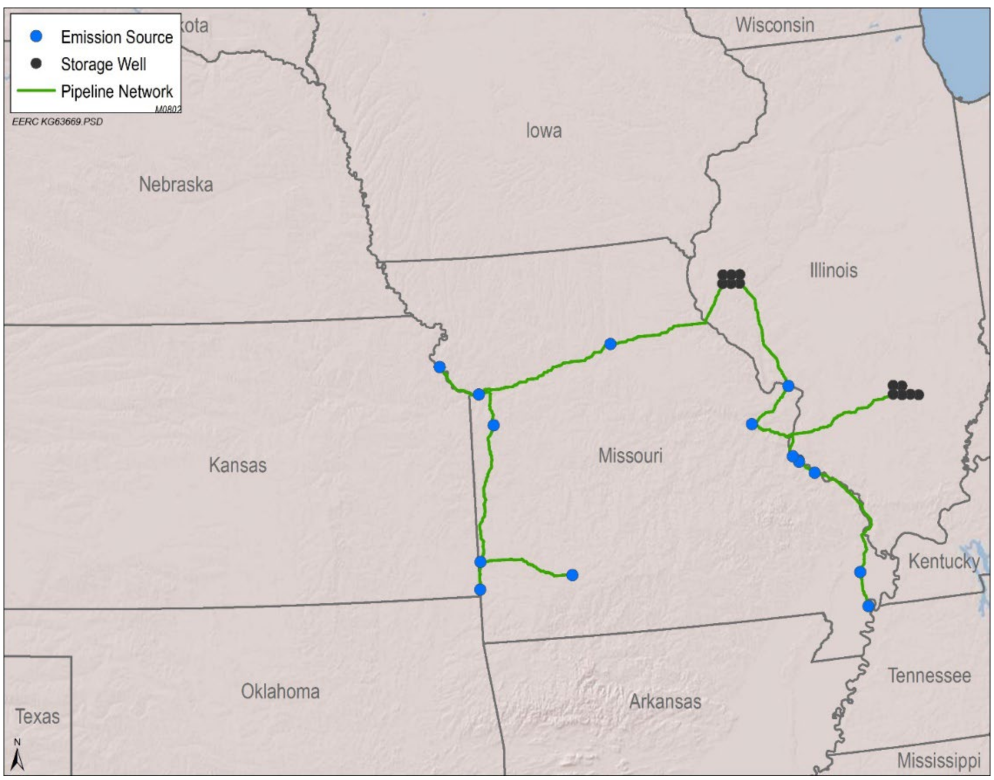

Figure A-3. Source, storage, and pipeline network for MO_IL_KS_61-Mt scenario.

Table A-4. Listing of Sources and Storage for MO_IL_KS_61-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
4005	Thomas Hill Energy Center	-92.6392	39.5531	1.07
3962	John Twitty	-93.3892	37.1519	1.74
3924	Asbury	-94.5913	37.3596	0.85
3942	Dogwood Energy Facility	-94.3006	38.7931	0.96
3957	Iatan Generating Station	-94.98	39.4472	7.50
3954	Hawthorn Generating Station	-94.4778	39.1306	2.80
4007	Thomas Hill Energy Center	-92.6392	39.5531	7.85
3997	Sioux	-90.2917	38.9158	1.52
3963	Labadie	-90.8361	38.5583	14.07
3978	New Madrid Power Plant	-89.5617	36.5147	6.19
3995	Sikeston	-89.6209	36.8791	1.55
3974	Mississippi Lime Company	-90.0678	37.9742	2.61
3955	Holcim (US) Inc Ste Genevieve Plant	-90.257947	38.109942	2.87
3991	Rush Island	-90.2625	38.1306	5.27
3989	River Cement Company DBA Buzzi Unicem USA	-90.3366	38.1804	1.69
80238	Sink 7	-90.799309	40.0515885	1.5
80212	Sink 8	-90.915936	40.0614965	4
80189	Sink 9	-91.032592	40.0712788	4
80190	Sink 10	-91.020469	40.1607573	4
80239	Sink 11	-90.786877	40.1410335	4
80213	Sink 12	-90.903658	40.1509584	4
103243	Sink 15	-88.555053	38.6562095	6
103187	Sink 16	-88.669095	38.6684795	6
103130	Sink 17	-88.78317	38.6806275	6
103131	Sink 18	-88.768608	38.7698225	7
103073	Sink 19	-88.882859	38.781868	6
103072	Sink 20	-88.897279	38.6926533	6

Table A-5. Summary of Pipeline Segments for MO_IL_KS_61-Mt Scenario

MO_IL-KS_61Mt v3

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Segment	Start	End	Elevations Start	Elevations End	Flow Mt/yr	Flow MMSCFD	Pressures Inlet	Pressures Outlet	Length kM	Length Miles	Cost of Pump Stations for System Capital	Cost of Pump Stations for System Operating	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	4005	3924	978	955	1.07	55.3	2,000	1,500	33.7	21.0	$0.3	$0.1	0	8	6.7	$16.4	$98,119	$0.4	$22.0	0	8	6.7	$16.4	$98,119	$1.0	$27.9
2	3962	3924	1254	955	1.74	90.4	2,000	1,500	119.6	74.3	$0.5	$0.2	0	12	10.0	$66.9	$75,070	$1.3	$82.4	1	10	8.9	$60.1	$80,861	$1.5	$77.5
3	3924	3942	955	950	3.66	189.9	2,000	1,600	175.1	108.8			0	20	15.6	$172.4	$79,210	$1.9	$191.4	3	12	11.9	$99.3	$76,037	$2.9	$127.8
4	3942	Birmingham Fork	950	736	4.61	239.5	1,600	1,500	50.1	31.1	$1.4	$0.5	0	20	15.4	$50.8	$81,591	$0.6	$63.2	1	16	14.1	$39.8	$79,901	$0.7	$53.2
5	3957	3954	768	804	7.50	389.4	2,000	1,600	66.4	41.3			0	16	12.2	$40.6	$61,517	$1.0	$50.6	0	16	12.2	$40.6	$61,517	$1.0	$50.6
6	3954	Birmingham Fork	804	736	10.30	534.6	1,600	1,500	5.9	3.7	$2.7	$1.1	0	16	14.9	$6.5	$110,143	$0.1	$21.7	0	16	14.9	$6.5	$110,143	$0.1	$21.7
7	Birmingham Fork	4007	736	737	14.91	774.2	2,000	1,500	176.8	109.9	$3.3	$1.6	0	30	25.6	$298.1	$90,446	$1.9	$336.6	1	24	22.4	$227.4	$86,248	$3.5	$281.9
8	4007	Sink 9	737	721	22.76	1,181.7	2,000	1,500	174.9	108.7	$5.1	$2.4	0	36	30.0	$381.4	$97,501	$1.9	$429.8	1	30	26.3	$300.0	$92,022	$4.3	$372.8
9	Sink 9	sink 10	721	702	12.00	623.0	2,000	1,900	10.9	6.8			0	20	18.1	$12.7	$93,807	$0.2	$14.4	0	20	18.1	$12.7	$93,807	$0.2	$14.4
10	sink 10	sink 12	702	703	8.00	415.3	1,900	1,800	10.4	6.4			0	20	15.5	$12.1	$93,834	$0.2	$13.7	0	20	15.5	$12.1	$93,834	$0.2	$13.7
11	sink 12	sink 11	703	587	4.00	207.7	1,800	1,700	10.4	6.4			0	12	11.2	$7.6	$98,163	$0.2	$9.2	0	12	11.2	$7.6	$98,163	$0.2	$9.2
12	Sink 9	Sink 8	721	747	6.76	351.0	2,000	1,900	9.7	6.0			0	16	14.6	$9.3	$96,378	$0.2	$10.8	0	16	14.6	$9.3	$96,378	$0.2	$10.8
13	Sink 8	Sink 7	747	678	2.76	143.4	1,900	1,800	10.4	6.5			0	10	10.0	$7.0	$109,085	$0.2	$8.7	0	10	10.0	$7.0	$109,085	$0.2	$8.7
14	Sink 7	3997	678	448	1.24	64.3	1,800	1,500	141.4	87.8	$0.4	$0.1	0	10	9.8	$70.1	$79,811	$1.5	$87.3	0	10	9.8	$70.1	$79,811	$1.5	$87.3
15	3997	3963	448	490	2.76	143.3	2,000	1,500	68.4	42.5	$0.7	$0.3	0	12	11.3	$39.1	$76,816	$0.8	$50.6	0	12	11.3	$39.1	$76,816	$0.8	$50.6
16	3963	Merrimac Fork	490	616	16.83	873.7	2,000	1,500	57.0	35.4	$3.7	$1.8	0	24	21.9	$73.6	$86,618	$0.7	$101.9	0	24	21.9	$73.6	$86,618	$0.7	$101.9
17	3978	3995	300	311	6.19	321.4	2,000	1,500	42.6	26.5	$1.4	$0.7	0	16	13.9	$33.9	$80,139	$0.5	$47.1	0	16	13.9	$33.9	$80,139	$0.5	$47.1
18	3995	3974	311	435	7.74	401.9	2,000	1,500	162.3	100.8	$1.8	$0.8	0	24	19.9	$205.7	$85,006	$1.8	$233.4	1	20	17.2	$161.6	$80,136	$2.6	$197.6
19	3974	3955	435	399	10.35	537.2	2,000	1,750	24.0	14.9			0	20	17.0	$25.4	$85,231	$0.3	$28.5	0	20	17.0	$25.4	$85,231	$0.3	$28.5
20	3955	3991 Fork	399	410	13.22	686.4	1,750	1,500	2.4	1.5	$3.1	$1.4	0	16	12.2	$3.9	$164,527	$0.1	$22.0	0	16	12.2	$3.9	$164,527	$0.1	$22.0
21	3991	3991 Fork	410	410	5.27	273.4	2,050	2,000	1.5	0.9			0	12	10.1	$2.8	$256,220	$0.1	$3.5	0	12	10.1	$2.8	$256,220	$0.1	$3.5
22	3991 Fork	3989	410	407	18.49	959.8	2,000	1,800	7.8	4.8			0	24	19.7	$17.9	$153,569	$0.2	$19.7	0	24	19.7	$17.9	$153,569	$0.2	$19.7
23	3989	Merrimac Fork	407	616	20.17	1,047.3	1,800	1,500	19.0	11.8	$4.6	$2.2	0	24	21.8	$25.9	$91,603	$0.3	$54.9	0	24	21.8	$25.9	$91,603	$0.3	$54.9
24	Merrimac Fork	Sink 20	616	560	37.00	1,921.0	2,000	1,500	139.2	86.5	$8.1	$4.0	0	42	34.4	$383.3	$105,500	$1.5	$446.2	0	42	34.4	$383.3	$105,500	$1.5	$446.2
25	Sink 20	Sink 19	560	558	13.00	674.9	2,000	1,900	11.2	7.0			0	36	29.9	$26.5	$106,029	$0.2	$28.3	1	20	18.7	$13.7	$98,384	$0.5	$18.2
26	Sink 19	Sink 18	558	581	7.00	363.4	1,900	1,700	11.0	6.8			0	16	14.2	$10.2	$93,437	$0.2	$11.9	0	16	14.2	$10.2	$93,437	$0.2	$11.9
27	Sink 20	Sink 17	560	520	18.00	934.5	2,000	1,900	11.0	6.9			0	30	24.8	$20.7	$100,653	$0.2	$22.4	0	30	24.8	$20.7	$100,653	$0.2	$22.4
28	Sink 17	Sink 16	520	532	12.00	623.0	1,900	1,800	10.6	6.6			0	20	16.6	$12.4	$94,379	$0.2	$14.1	0	20	16.6	$12.4	$94,379	$0.2	$14.1
29	Sink 16	Sink 15	532	489	6.00	311.5	1,800	1,700	10.3	6.4			0	16	13.6	$9.8	$95,157	$0.2	$11.4	0	16	13.6	$9.8	$95,157	$0.2	$11.4
	Totals				58.5			14		977.9	$37.1	$17.3				$2,043.2		$18.4	$2,437.8	8			$1,743.2		$25.4	$2,207.6

Number of years for project 10

Unit Cost (Based on 2011 Costs in Model) = $4.17 per tonne CO_2 | Unit Cost (Based on 2011 Costs in Model) = $3.77 per tonne CO_2

Average Pipeline OD = 23.0 inches | Average Pipeline OD = 20.0 inches

Average Pipeline Cost = $90,674 per inch-mile | Average Pipeline Cost = $89,100 per inch-mile

The candidate network shown in Figure A-4 comprises 39 sources and 44 possible storage well locations. The total volume of the candidate sources is 48.5 million metric tons. Data for the sources included in the network are shown in Table A-6. This scenario was setup to compare options for storing CO_2 in North Dakota vs. Illinois and to identify optimized capture networks at 16, 32, and 43 million metric tons annually for comparison.

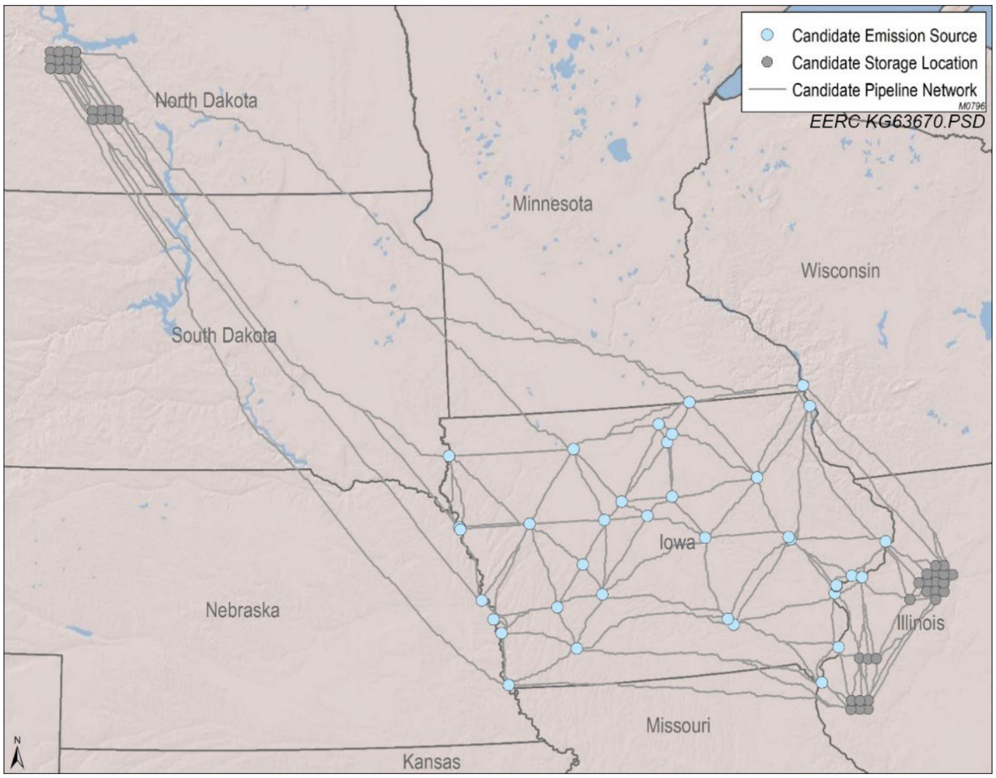

Figure A-4. Candidate network showing optimal routes for pipeline connections between Iowa CO_2 sources greater than 250,000 metric tons annual production and candidate storage well locations in North Dakota or Illinois.

Table A-6. Source Data for IA_ND_IL Candidate Network

ID	capMax (MtCO2/y)	LON	LAT	NAME	Source Type
2150	0.515	-92.917	43.500	Absolute Energy, LLC	Ethanol Production
2168	1.215	-91.117	40.741	Burlington (IA)	Electric Generating
2176	2.432	-96.365	42.328	CF Industries Nitrogen, LLC-Port Neal Nitrogen Complex	Ammonia Manufacturing
2179	0.785	-90.695	41.459	Davenport Plant	Cement Production
2186	0.640	-95.032	41.418	Elite Octane	Ethanol Production
2187	1.049	-93.292	43.094	Emery Station	Electric Generating
2188	0.389	-90.296	41.807	Equistar Chemicals LP	Other Chemicals
2190	0.567	-95.355	42.331	Flint Hills Resources Arthur, LLC	Ethanol Production
2191	0.450	-93.280	42.507	Flint Hills Resources Iowa Falls, LLC	Ethanol Production
2192	0.553	-92.031	42.639	Flint Hills Resources, LLC - Fairbank Ethanol Plant	Ethanol Production
2193	0.548	-94.382	41.524	Flint Hills Resources Menlo, LLC	Ethanol Production
2196	1.709	-96.380	42.325	George Neal North	Electric Generating
2197	1.451	-96.362	42.302	George Neal South	Electric Generating
2201	0.431	-91.061	41.398	Grain Processing Corp	Ethanol Production
2209	0.250	-91.666	41.969	Ingredion Incorperated	Ethanol Production
2215	0.585	-94.017	42.499	Koch Fertilizer Ft. Dodge, LLC	Ammonia Manufacturing
2217	0.486	-91.167	43.336	Lansing	Electric Generating
2218	0.405	-93.212	43.179	Lehigh Cement Co, LLC	Cement Production
2220	0.364	-90.685	41.463	Linwood Mining & Minerals Corporation	Lime Manufacturing
2224	3.294	-91.094	41.315	Louisa	Electric Generating
2230	1.158	-91.057	41.392	Muscatine	Electric Generating
2238	4.050	-92.556	41.096	Ottumwa	Electric Generating
2241	0.359	-94.795	40.966	Pinnacle Ethanol LLC d/b/a Poet Biorefining - Corning	Ethanol Production
2244	0.341	-93.663	42.329	POET Biorefining	Ethanol Production
2245	0.331	-94.287	42.320	POET Biorefining - Gowrie, LLC	Ethanol Production
2246	0.321	-93.390	43.291	POET Biorefining - Hanlontown LLC	Ethanol Production
2248	0.267	-94.631	41.860	Poet Biorefining - Coon Rapids	Ethanol Production
2251	0.486	-91.639	41.944	Prairie Creek	Electric Generating
2256	0.413	-91.398	40.388	Roquette America Inc.	Food Processing
2262	0.378	-90.823	41.486	SSAB Iowa Inc.	Iron and Steel Production
2264	1.497	-92.863	42.047	Sutherland	Electric Generating
2281	0.288	-94.655	43.097	Voyager Ethanol LLC - Poet Biorefining-Emmetsburg	Ethanol Production
2282	7.973	-95.841	41.180	Walter Scott Jr. Energy Center	Electric Generating
4318	1.186	-96.098	41.538	Cargill Corn Milling North America	Ethanol Production
4353	6.766	-95.777	40.622	Nebraska City Station	Electric Generating
4359	2.115	-95.946	41.330	North Omaha Station	Electric Generating
6594	0.311	-96.477	43.097	POET Biorefining - Hudson (Sioux River Ethanol)	Ethanol Production
8199	1.247	-91.233	43.559	Genoa	Electric Generating
8463	0.498	-92.636	41.162	Cargill Inc - Eddyville	Ethanol Production

Figure A-5 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 16 million tonnes/year (33% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified three sources to generate the target 16 million metric tons of CO_2 annually, with those sources storing into four wells. Table A-7 lists the source and sink data for Figure A-5. Table A-8 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without additional pumps installed on the pipeline segments. SimCCS Gateway produced resulting costs of \$45.37, \$2.19, and \$6.60 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of \$54.15/ton CO_2.

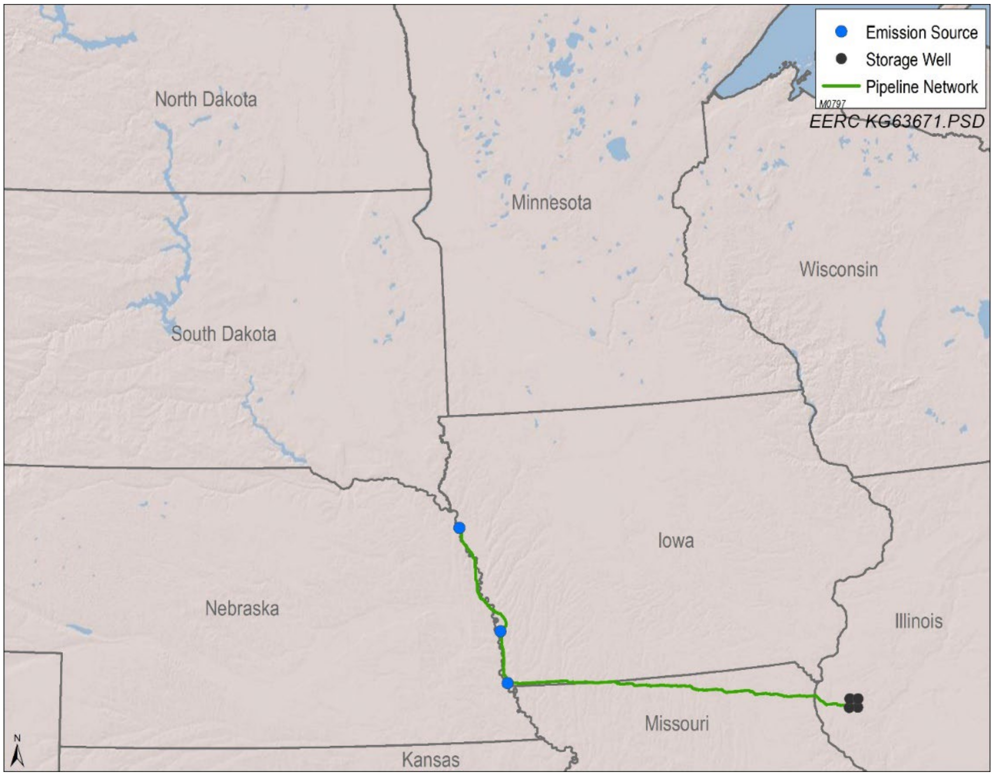

Figure A-5. Source, storage, and pipeline network for IA_ND_IL 16-Mt scenario.

Table A-7. Listing of Sources and Sinks for IA_ND_IL 16-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
2197	George Neal South	-96.3622	42.3022	1.26
2282	Walter Scott Jr. Energy Center	-95.8408	41.18	7.97
4353	Nebraska City Station	-95.7765	40.6215	6.77
80212	Sink 2	-90.91593594	40.06149653	4
80189	Sink 3	-91.03259233	40.07127875	4
80190	Sink 4	-91.02046871	40.16075727	4
80213	Sink 6	-90.90365833	40.15095841	4

Table A-8. Summary of Pipeline Segments for IA_ND_IL_16-Mt Scenario

IA_ND_IL_16 Mt

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			Elevations		Flow		Pressures		Length		Cost of Pump Stations for System															
Segment	Start	End	Start	End	Mt/yr	MMSCFD	Inlet	Outlet	kM	Miles	Capital	Operating	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	2197	2282	1289	1060	1.26	65.5	2,000	1,500	173.6	107.9	$0.4	$0.1	0	10	9.6	$85.7	$79,426	$1.9	$106.27	2	8	7.9	$77.0	$89,157	$2.2	$100.3
2	2282	4353	1060	1181	9.23	479.4	2,000	1,500	63.3	39.3	$2.1	$1.0	0	20	17.8	$63.6	$80,866	$0.7	$82.8	0	20	17.8	$63.6	$80,866	$0.7	$82.8
3	4353	Sink 3	1181	721	16.00	830.7	2,000	1,500	432.5	268.8	$3.6	$1.7	0	36	29.6	$940.0	$97,154	$4.6	$1,006.8	1	30	26.5	$729.7	$90,506	$6.3	$813.7
4	Sink 3	Sink 2	721	747	4.00	207.7	2,000	1,900	10.4	6.4	$0.3	$0.1	0	16	12.1	$9.8	$94,579	$0.2	$12.5	0	16	12.1	$9.8	$94,579	$0.2	$12.5
5	Sink 3	Sink 4	721	702	8.00	415.3	2,000	1,900	10.0	6.2			0	20	15.2	$11.8	$94,948	$0.2	$13.4	0	20	15.2	$11.8	$94,948	$0.2	$13.4
6	Sink 4	Sink 6	702	703	4.00	207.7	1,900	1,800	10.4	6.4			0	12	11.9	$7.6	$98,172	$0.2	$9.2	0	12	11.9	$7.6	$98,172	$0.2	$9.2
	Totals				**16.0**			**3**		**435.1**	**$6.3**	**$2.9**				**$1,118.4**		**$7.7**	**$1,231.0**	3			**$899.4**		**$9.7**	**$1,031.9**

Number of years for project 10

Unit Cost (Based on 2011 Costs in Model) = **$7.69** **per tonne CO_2**

Average Pipeline OD = **27.2** **inches**

Average Pipeline Cost = **$94,419** **per inch-mile**

Unit Cost (Based on 2011 Costs in Model) = **$6.45** **per tonne CO_2**

Average Pipeline OD = **23.0** **inches**

Average Pipeline Cost = **$89,789** **per inch-mile**

Figure A-6 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 32 million tonnes/year (66% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified ten sources to generate the target 32 million metric tons of CO_2 annually, with those sources storing into five wells. Table A-9 lists the source and storage data for Figure A-6. Table A-9 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without pumping. SimCCS Gateway produced resulting costs of $51.78, $1.73, and $6.42 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of $59.93/ton CO_2. Increasing from the 16-Mt and 32-Mt capture scenarios results in a 14.1% increase in capture costs, 21% decrease in transportation costs, and 2.7% increase in storage costs, for a total cost increase of $5.78.

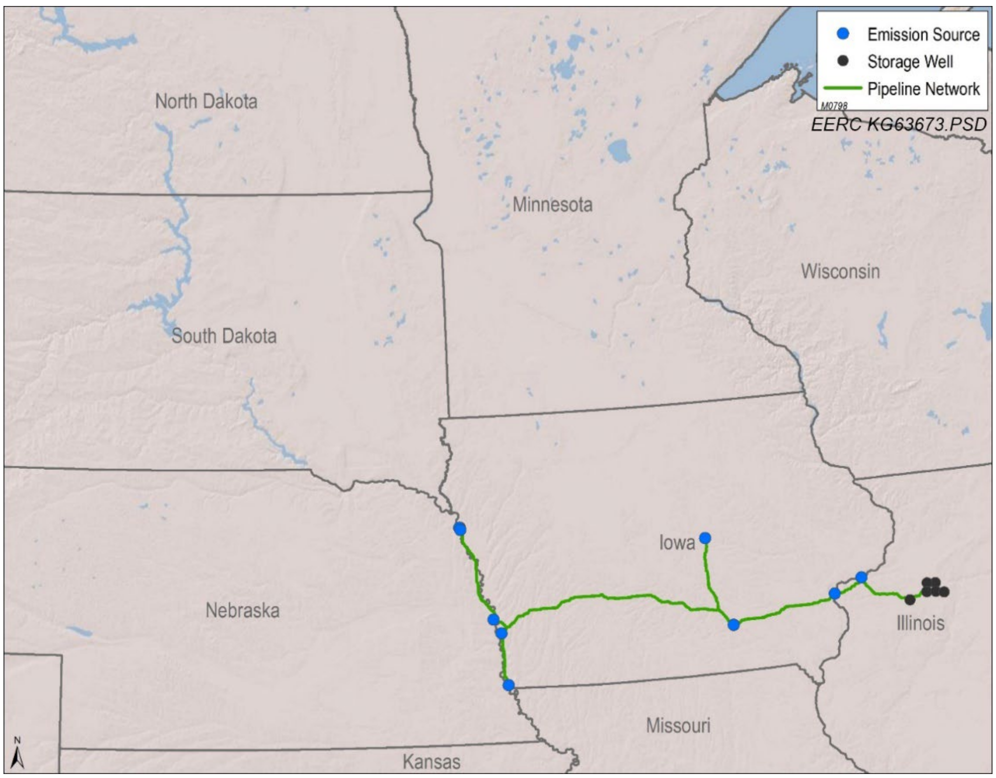

Figure A-6. Source, storage, and pipeline network for IA_ND_IL 32-Mt scenario.

Table A-9. Listing of Sources and Sinks for IA_ND_IL 32-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
2196	George Neal North	-96.3797	42.3251	0.69
2176	CF Industries Nitrogen, LLC-Port Neal Nitrogen Complex	-96.36489	42.32786	3.46
2197	George Neal South	-96.3622	42.3022	1.45
4359	North Omaha Station	-95.9458	41.3297	2.11
4353	Nebraska City Station	-95.7765	40.6215	6.77
2282	Walter Scott Jr. Energy Center	-95.8408	41.18	7.97
2264	Sutherland	-92.8627	42.0472	1.50
2238	Ottumwa	-92.5556	41.0961	4.05
2224	Louisa	-91.0936	41.3153	3.29
2179	Davenport Plant	-90.695252	41.45906	0.71
80566	Sink 11	-89.65676994	41.30659731	6
80517	Sink 12	-89.77549804	41.31779515	6
80424	Sink 13	-90.04090863	41.1612738	2
80516	Sink 17	-89.78977276	41.22857119	6
80565	Sink 18	-89.67120534	41.2173929	6
80614	Sink 19	-89.55267314	41.20608636	6

Table A-10. Summary of Pipeline Segments for IA_ND_IL_32-Mt Scenario

IA_ND_IL_32Mt — NETL Cost Estimates - 2022 version

Segment	Start	End	Elevations		Flow		Pressures		Length		Cost of Pump Stations for System		Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
			Start	End	Mt/yr	MMSCFD	Inlet	Outlet	kM	Miles	Capital	Operating														
1	2196	2176	1081	1008	0.69	35.6	2,000	1,900	1.7	1.1			0	6	4.1	$2.7	$419,150	$0.1	$3.40	0	6	4.1	$2.7	$419,150	$0.1	$3.4
2	2176	2197	1008	1074	4.14	215.0	1,900	1,800	3.0	1.9			0	12	10.0	$3.7	$163,274	$0.1	$4.5	0	12	10.0	$3.7	$163,274	$0.1	$4.5
3	2197	4359	1074	1076	5.59	290.4	1,800	1,550	123.3	76.6			0	20	18.7	$122.0	$79,573	$1.4	$135.5	2	16	15.1	$95.6	$77,978	$2.0	$115.2
4	4359	Omaha Fork	1076	1076	7.71	400.2	1,550	1,500	20.2	12.5	$1.3	$0.4	0	24	19.6	$27.4	$90,945	$0.3	$35.1	0	24	19.6	$27.4	$90,945	$0.3	$35.1
5	4353	2282	928	1076	6.77	351.3	2,000	1,600	62.1	38.6			0	20	16.6	$62.5	$80,961	$0.7	$69.6	0	20	16.6	$62.5	$80,961	$0.7	$69.6
6	2282	Omaha Fork	1076	1076	14.74	765.2	1,600	1,500	10.0	6.2	$3.3	$1.4	0	24	19.6	$14.6	$98,373	$0.2	$34.0	0	24	19.6	$14.6	$98,373	$0.2	$34.0
7	Omaha Fork	Beacon Fork	1076	744	22.45	1,165.4	2,000	1,500	284.2	176.6	$5.0	$2.2	0	36	31.5	$618.3	$97,255	$3.0	$675.8	1	30	28.1	$482.8	$91,128	$5.5	$564.3
8	2264	Beacon Fork	883	744	1.50	77.7	2,000	1,600	91.5	56.8	$0.4	$0.1	0	12	11.8	$156.4	$229,250	$3.0	$188.8	2	10	9.7	$139.7	$245,716	$3.3	$174.7
9	Beacon Fork	2238	744	685	23.94	1,243.1	1,600	1,500	26.7	16.6	$5.3	$2.4	0	24	22.0	$35.6	$89,583	$0.3	$67.8	0	24	22.0	$35.6	$89,583	$0.3	$67.8
10	2238	2224	685	576	27.99	1,453.4	2,000	1,500	135.2	84.0	$6.2	$3.0	0	36	30.5	$295.2	$97,611	$1.5	$346.1	0	36	30.5	$295.2	$97,611	$1.5	$346.1
11	2224	Andalusia Fork	576	620	31.29	1,624.4	2,000	1,800	41.0	25.5			0	24	19.7	$7.2	$11,702	$0.1	$8.1	0	24	19.7	$7.2	$11,702	$0.1	$8.1
12	2179	Andalusia Fork	562	620	0.71	37.0	2,000	1,800	2.3	1.4			0	6	4.1	$2.9	$339,562	$0.1	$3.6	0	6	4.1	$2.9	$339,562	$0.1	$3.6
13	Andalusia Fork	Sink 13	620	823	32.00	1,661.4	1,800	1,500	95.6	59.4	$7.1	$3.1	0	42	35.5	$263.9	$105,753	$1.1	$313.0	1	36	30.1	$213.7	$99,907	$3.1	$283.5
14	Sink 13	Sink 17	823	713	30.00	1,557.5	2,000	1,900	25.5	15.9			0	36	28.9	$57.6	$100,797	$0.3	$60.8	0	36	28.9	$57.6	$100,797	$0.3	$60.8
15	Sink 17	Sink 12	713	832	12.00	623.0	1,900	1,800	10.7	6.6			0	24	20.2	$15.4	$97,152	$0.2	$17.1	0	24	20.2	$15.4	$97,152	$0.2	$17.1
16	Sink 12	Sink 11	832	783	6.00	311.5	1,800	1,700	10.2	6.3			0	16	13.5	$9.6	$94,932	$0.2	$11.2	0	16	13.5	$9.6	$94,932	$0.2	$11.2
17	Sink 17	Sink 18	713	737	12.00	623.0	1,900	1,800	10.9	6.8			0	20	18.7	$12.7	$93,781	$0.2	$14.4	0	20	18.7	$12.7	$93,781	$0.2	$14.4
18	Sink 18	Sink 19	737	826	6.00	311.5	1,800	1,700	10.7	6.6			0	16	15.0	$10.0	$94,092	$0.2	$11.7	0	16	15.0	$10.0	$94,092	$0.2	$11.7
	Totals				**32.0**			**6**		**599.5**	**$28.5**	**$12.7**				**$1,717.6**		**$12.8**	**$2,000.7**	6			**$1,488.8**		**$18.1**	**$1,825.4**

Number of years for project **10**

Unit Cost (Based on 2011 Costs in Model) = **$6.25** **per tonne CO_2** | **Unit Cost (Based on 2011 Costs in Model) =** **$5.70** **per tonne CO_2**

Average Pipeline OD = **29.1** **inches** | **Average Pipeline OD =** **26.0** **inches**

Average Pipeline Cost = **$98,519** **per inch-mile** | **Average Pipeline Cost =** **$95,451** **per inch-mile**

Figure A-7 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 43 million tonnes/year (90% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS identified 24 sources to generate the target 43 million metric tons of CO_2 annually, with those sources storing into seven wells. Table A-11 lists the source and sink data for Figure A-7. Table A-12 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without pumping. SimCCS produced resulting costs of $63.81, $1.81, and $6.38 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of $72.00/ton CO_2. Increasing from the 32-Mt and 43-Mt capture scenarios results in a 23.2% increase in capture costs, 4.6% increase in transportation costs, and 0.6% decrease in storage costs, for a total cost increase of $12.07.

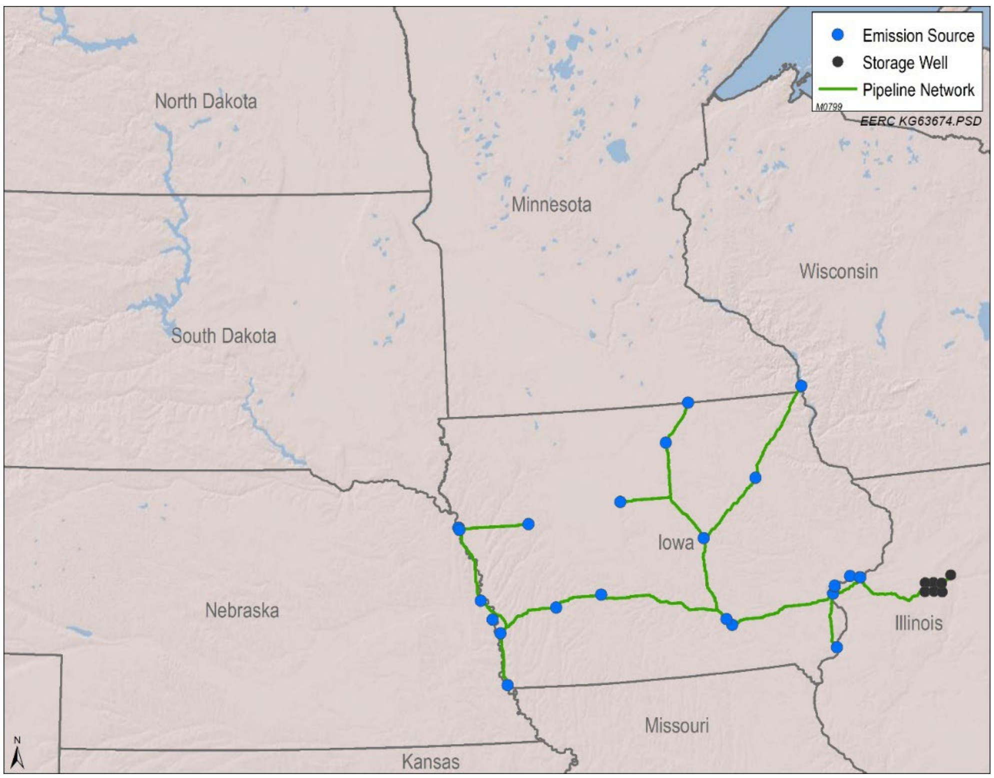

Figure A-7. Source, storage, and pipeline network for IA_ND_IL 43-Mt scenario.

Table A-11. Listing of Sources and Storage for IA_ND_IL 43-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
2190	Flint Hills Resource Arthur LLC	-95.3549	42.3308	0.57
2196	George Neal North	-96.3797	42.3251	1.71
2176	CF Industries Nitrogen, LLC-Port Neal Nitrogen Complex	-96.36489	42.32786	0.72
2197	George Neal South	-96.3622	42.3022	3.16
4318	Cargill Corn Milling North America	-96.0977	41.53789	1.19
4359	North Omaha Station	-95.9458	41.3297	2.11
4353	Nebraska City Station	-95.7765	40.6215	6.77
2282	Walter Scott Jr. Energy Center	-95.8408	41.18	7.97
2186	Elite Octane	-95.03182	41.41772	0.64
2193	Flint Hills Reources Menlo, LLC	-94.3819	41.5236	0.55
2150	Absolute Energy LLD	-92.91709	43.49951	0.51
2187	Emery Station	-93.2922	43.094	1.05
2215	Koch Fertilizer Ft. Dodge, LLC	-94.017177	42.499406	0.58
2264	Sutherland	-92.8627	42.0472	1.50
8199	Genoa	-91.2333	43.5592	1.25
2192	Flint Hills Resources LLC -- Fairbank Ethanol Plant	-92.031139	42.639333	0.55
8463	Cargill Inc - Eddyville	-92.6361	41.16226	0.50
2238	Ottumwa	-92.5556	41.0961	4.05
2201	Grain Processing Corp	-91.0611	41.3981	0.43
2230	Muscatine	-91.0569	41.3917	1.16
2168	Burlington (IA)	-91.1168	40.7412	1.22
2224	Louisa	-91.0936	41.3153	3.29
2262	Walter Scott Jr. Energy Center	-90.82278	41.48553	0.38
2220	Linwood Mining & Minerals Corporarion	-90.68519	41.46346	0.32
2179	Davenport Plant	-90.695252	41.45906	0.83
80566	Sink 11	-89.65676994	41.30659731	6
80517	Sink 12	-89.77549804	41.31779515	6
80516	Sink 17	-89.78977276	41.22857119	6
80565	Sink 18	-89.67120534	41.2173929	6
80614	Sink 19	-89.55267314	41.20608636	6
80615	Sink 20	-89.53807727	41.29527101	6
80666	Sink 23	-89.40460508	41.37297406	7

Table A-12. Summary of Pipeline Segments for IA_ND_IL_43-Mt Scenario

IA_ND_IL_43 Mt

NETL Cost Estimates - 2022 version

Segment	Start	End	Elevations		Flow		Pressures		Length		Cost of Pump Stations for System		Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
			Start	End	Mt/yr	MMSCFD	Inlet	Outlet	kM	Miles	Capital	Operating														
1	2190	2196	1296	1008	0.57	29.4	2,000	1,500	83.6	52.0	$0.2	$0.1	0	8	6.1	$37.8	$90,878	$0.9	$47.98	1	6	5.4	$34.0	$109,025	$1.0	$44.8
2	2196	2176	1008	1081	1.71	88.7	2,000	1,950	0.7	0.4			0	8	6.3	$2.3	$667,817	$0.1	$2.9	0	8	6.3	$2.3	$667,817	$0.1	$2.9
3	2176	2197	1081	1074	2.43	126.3	1,950	1,900	3.0	1.9			0	10	8.6	$3.5	$185,912	$0.1	$4.3	0	10	8.6	$3.5	$185,912	$0.1	$4.3
4	2197	4318	1074	1004	6.16	319.8	1,900	1,500	91.4	56.8	$1.4	$0.7	0	20	15.9	$91.0	$80,111	$1.0	$109.2	1	16	14.0	$71.8	$79,059	$1.7	$96.7
5	4318	Cresent Fork	1004	1021	7.35	381.4	2,000	1,500	23.9	14.8	$1.7	$0.8	0	16	13.3	$19.9	$83,767	$0.3	$32.5	0	16	13.3	$19.9	$83,767	$0.3	$32.5
6	4359	Cresent Fork	1076	1021	2.11	109.8	2,000	1,500	8.8	5.5	$0.5	$0.2	0	8	6.7	$5.8	$132,122	$0.1	$10.1	0	8	6.7	$5.8	$132,122	$0.1	$10.1
7	Cresent Fork	Council Bluffs Fork	1021	994	9.46	491.2	2,000	1,900	24.6	15.3			0	24	19.2	$33.0	$90,132	$0.3	$36.2	1	20	17.0	$26.5	$86,869	$0.5	$31.7
8	4353	2282 Fork	928	982	6.77	351.3	2,000	1,500	63.3	39.3	$1.9	$0.9	0	20	15.6	$63.6	$80,866	$0.7	$81.8	0	20	15.6	$63.6	$80,866	$0.7	$81.8
9	2282	2282 Fork	982	982	7.97	413.9	2,000	1,900	1.2	0.7			0	12	10.1	$2.6	$301,830	$0.1	$3.3	0	12	10.1	$2.6	$301,830	$0.1	$3.3
10	2282 Fork	Council Bluffs Fork	982	994	14.74	765.2	1,900	1,500	11.8	7.4	$3.3	$1.6	0	20	15.8	$13.7	$92,916	$0.2	$34.7	0	20	15.8	$13.7	$92,916	$0.2	$34.7
11	Council Bluffs Fork	2186	994	1165	24.20	1,256.4	2,000	1,500	70.7	43.9	$5.4	$2.6	0	30	26.5	$120.4	$91,350	$0.8	$159.6	0	30	26.5	$120.4	$91,350	$0.8	$159.6
12	2186	2193	1165	1231	24.84	1,289.6	2,000	1,500	60.2	37.4	$5.5	$2.7	0	30	25.5	$102.9	$91,721	$0.7	$141.8	0	30	25.5	$102.9	$91,721	$0.7	$141.8
13	2193	Evans Fork	1231	738	25.39	1,318.1	2,000	1,500	151.5	94.1	$5.6	$2.7	0	36	28.7	$330.4	$97,497	$1.6	$379.7	1	30	25.8	$261.2	$92,482	$4.4	$337.7
14	2150	2187	1188	1189	0.51	26.7	2,000	1,500	57.6	35.8	$0.2	$0.1	0	6	5.7	$23.9	$111,279	$0.7	$31.3	0	6	5.7	$23.9	$111,279	$0.7	$31.3
15	2187	Iowa Falls Fork	1189	1110	1.56	81.2	2,000	1,500	66.4	41.3	$0.4	$0.2	0	10	8.8	$34.0	$82,459	$0.8	$43.7	1	8	7.7	$30.8	$93,281	$0.9	$42.2
16	2215	Iowa Falls Fork	1115	1110	0.58	30.4	2,000	1,500	73.3	45.6	$0.2	$0.1	0	8	6.2	$33.4	$91,567	$0.8	$42.5	1	6	5.4	$30.1	$110,117	$0.9	$39.9
17	Iowa Falls Fork	2264	1110	865	2.15	111.5	2,000	1,500	65.7	40.8	$0.6	$0.2	0	10	9.7	$33.6	$82,397	$0.7	$44.0	0	10	9.7	$33.6	$82,397	$0.7	$44.0
18	2264	2264 Fork	865	865	3.65	189.3	2,000	1,950	0.9	0.6			0	10	8.1	$2.5	$427,801	$0.1	$3.1	0	10	8.1	$2.5	$427,801	$0.1	$3.1
19	8199	2192	635	1014	1.25	64.7	2,000	1,500	130.4	81.0	$0.4	$0.1	0	10	9.9	$64.8	$80,015	$1.4	$80.8	2	8	7.7	$58.4	$90,103	$1.7	$77.1
20	2192	2264 Fork	1014	865	1.80	93.5	2,000	1,500	164.4	102.2	$1.0	$0.4	0	12	11.0	$91.3	$74,496	$1.8	$114.1	1	10	9.7	$81.7	$79,965	$2.0	$106.4
21	2264 Fork	Evans Fork	865	738	5.45	282.7	2,000	1,500	90.6	56.3	$1.3	$0.6	0	16	15.0	$69.8	$77,539	$1.0	$87.0	0	16	15.0	$69.8	$77,539	$1.0	$87.0
22	Evans Fork	8463	738	674	30.83	1,600.8	2,000	1,900	15.8	9.8			0	30	27.2	$28.5	$96,966	$0.2	$30.7	0	30	27.2	$28.5	$96,966	$0.2	$30.7
23	8463	2238	674	719	31.33	1,626.6	1,900	1,800	10.9	6.8			0	30	27.4	$20.4	$100,454	$0.2	$22.1	0	30	27.4	$20.4	$100,454	$0.2	$22.1
24	2238	2224	719	574	35.38	1,836.9	1,800	1,500	135.2	84.0	$7.9	$3.8	0	42	36.2	$372.3	$105,510	$1.5	$433.1	1	36	32.1	$299.9	$99,167	$3.8	$383.7
25	2201	2230	594	576	0.43	22.4	2,000	1,900	0.9	0.6			0	4	2.8	$2.3	$1,009,505	$0.1	$3.0	0	4	2.8	$2.3	$1,009,505	$0.1	$3.0
26	2230	2224	576	574	1.59	82.5	1,900	1,500	9.3	5.8	$0.5	$0.2	0	8	6.4	$6.0	$130,002	$0.2	$9.7	0	8	6.4	$6.0	$130,002	$0.2	$9.7
27	2168	2224	541	574	1.22	63.1	2,000	1,500	68.9	42.8	$0.3	$0.1	0	10	8.2	$35.2	$82,263	$0.8	$44.7	0	10	8.2	$35.2	$82,263	$0.8	$44.7
28	2224	Andalusia Fork	574	620	41.48	2,153.5	2,000	1,500	41.0	25.5	$9.1	$4.4	0	36	28.8	$91.1	$99,246	$0.5	$149.5	0	36	28.8	$91.1	$99,246	$0.5	$149.5
29	2262	2179	761	566	0.38	19.6	2,050	2,000	13.0	8.1			0	24	22.0	$18.5	$95,566	$0.2	$20.4	0	24	22.0	$18.5	$95,566	$0.2	$20.4
30	2220	2179	565	566	0.70	36.1	2,100	2,050	0.694	0.4			0	4	4.0	$2.2	$1,285,210	$0.1	$2.8	0	4	4.0	$2.2	$1,285,210	$0.1	$2.8
31	2179	Andalusia Fork	566	620	1.52	79.0	2,100	2,050	2.548	1.6			0	8	6.5	$3.1	$244,719	$0.1	$3.9	0	8	6.5	$3.1	$244,719	$0.1	$3.9
32	Andalusia Fork	Sink 17	620	700	43.00	2,232.5	2,000	1,500	96.765	60.1	$9.5	$4.6	0	42	34.7	$266.9	$105,707	$1.1	$333.2	0	42	34.7	$266.9	$105,707	$1.1	$333.2
33	Sink 17	Sink 18	700	716	12.00	623.0	2,000	1,900	10.916	6.8			0	20	18.5	$12.7	$93,781	$0.2	$14.4	0	20	18.5	$12.7	$93,781	$0.2	$14.4
34	Sink 18	Sink 19	716	826	6.00	311.5	2,000	1,900	10.684	6.6			0	20	15.3	$12.4	$93,460	$0.2	$14.1	0	20	15.3	$12.4	$93,460	$0.2	$14.1
35	Sink 17	Sink 12	700	818	25.00	1,298.0	2,000	1,900	10.658	6.6			0	30	26.7	$19.9	$100,098	$0.2	$21.5	0	30	26.7	$19.9	$100,098	$0.2	$21.5
36	Sink 12	Sink 11	818	776	19.00	986.4	1,900	1,800	10.207	6.3			0	24	21.0	$14.8	$97,464	$0.2	$16.4	0	24	21.0	$14.8	$97,464	$0.2	$16.4
37	Sink 11	Sink 20	776	673	13.00	674.9	1,800	1,700	10.67	6.6			0	20	17.8	$12.4	$93,583	$0.2	$14.1	0	20	17.8	$12.4	$93,583	$0.2	$14.1
38	Sink 20	Sink 23	673	673	7.00	363.4	1,700	1,600	15.997	9.9			0	20	16.1	$17.6	$88,402	$0.2	$19.8	0	20	16.1	$17.6	$88,402	$0.2	$19.8
	Totals				**43.0**			**21**		**1,061.2**	**$56.9**	**$27.0**				**$2,116.4**		**$20.1**	**$2,644.1**	6			**$1,922.8**		**$26.7**	**$2,516.9**

Number of years for project 10

Unit Cost (Based on 2011 Costs in Model) = **$6.15** **per tonne CO_2** | **Unit Cost (Based on 2011 Costs in Model) =** **$5.85** **per tonne CO_2**

Average Pipeline OD = **21.1** **inches** | **Average Pipeline OD =** **19.3** **inches**

Average Pipeline Cost = **$94,329** **per inch-mile** | **Average Pipeline Cost =** **$94,091** **per inch-mile**

The candidate network shown in Figure A-8 comprises two sources and 36 possible storage well locations. The total volume of the candidate sources is 21.9 million metric tons. Data for the sources included in the network are shown in Table A-13. This scenario was setup to evaluate the cost of transporting CO_2 from Missouri's largest sources over into Nebraska and Wyoming for comparison against CO_2 storage in Illinois.

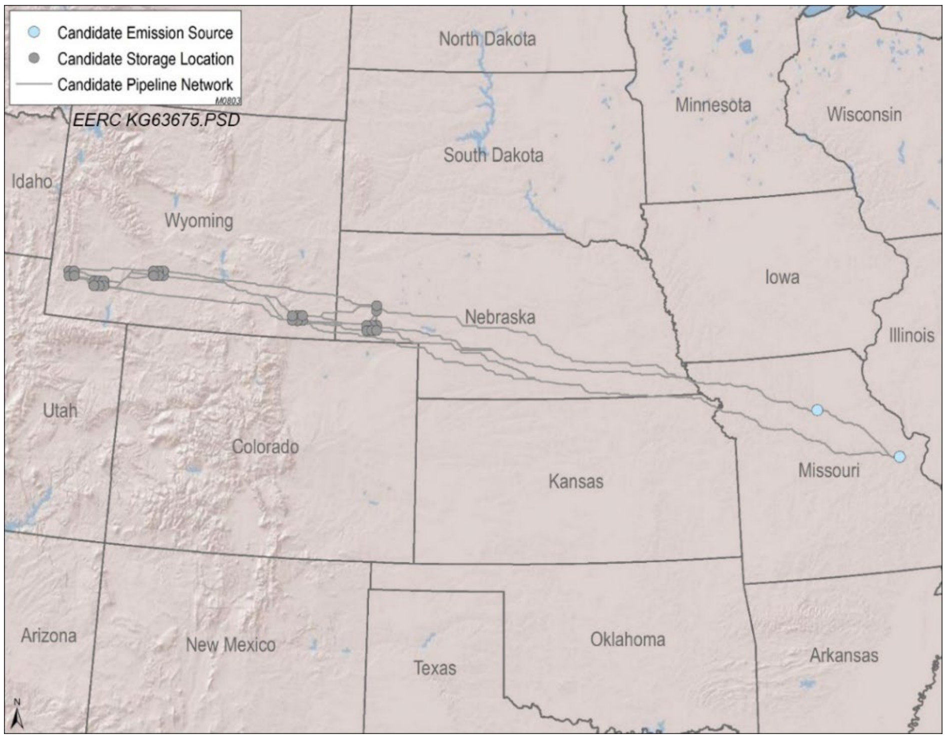

Figure A-8. Candidate network showing optional routes for pipeline connections between Missouri CO_2 sources greater than 250,000 metric tons annual production and candidate storage well locations in Nebraska or Wyoming.

Table A-13. Source Data for MO_NE_WY Two-Source Candidate Network

ID	capMax (MtCO2/y)	LON	LAT	NAME	Source Type
3963	14.069024	-90.8361	38.5583	Labadie	Electric Generating
4007	7.850281	-92.6392	39.5531	Thomas Hill Energy Center	Electric Generating

Figure A-9 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 21.9 million tonnes/year (100% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified two sources to generate the target 21.9 million metric tons of CO_2 annually, with those sources storing into seven wells. Table A-14 lists the source and storage data for Figure A-9. Table A-15 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without pumping. SimCCS Gateway produced

Figure A-9. Source, storage, and pipeline network for MO-NE-WY-2_source_21.9-Mt scenario.

resulting costs of $40.29, $3.73, and $6.97 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of $51/ton CO_2. Comparing the 22-Mt target scenario with storage in Illinois to the 21.9-Mt two-source scenarios results in a 4.2% decrease in capture costs, 216.1% increase in transportation costs, and 8.7% increase in storage costs, for a total cost increase of $1.03. The significant increase in transport costs is because of low volume, elevation change of 6077 ft, and long transport distance.

Table A-14. Listing of Sources and Sinks for MO-NE-WY-2_source_ 21.9-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
3963	Labadie Power Plant	-90.8361	38.5583	14.05
4007	Thomas Hill Energy Center	-92.6392	39.5531	7.85
91007	Sink 9	-104.85396	41.3269647	6
91008	Sink 10	-104.86077	41.4168498	5
90958	Sink 11	-104.98018	41.4114852	5.4
90957	Sink 12	-104.9732	41.3216096	5.5

Table A-15. Summary of Pipeline Segments for MO-NE-WY-2_source_21.9-Mt scenario

MO-NE-WY-2source

Segment	Start	End	Elevations Start	Elevations End	Flow Mt/yr	Flow MMSCFD	Pressures Inlet	Pressures Outlet	Length kM	Length Miles	Cost of Pump Stations for System Capital	Cost of Pump Stations for System Operating
1	3963	4007	490	737	14.05	729.4	2,000	1,500	213.7	132.8	$3.1	$1.5
2	4007	Sink 9	737	6214	21.90	1,137.0	2,000	1,500	1,126.4	699.9	$0.0	$2.3
3	Sink 9	Sink 12	6214	6567	5.50	285.5	2,000	1,800	10.9	6.8		
4	Sink 9	Sink 10	6214	6310	10.40	539.9	2,000	1,800	10.4	6.5		
5	Sink 10	Sink 11	6310	6501	5.40	280.4	1,800	1,600	9.0	5.6		
	Totals				21.9			2		851.6	$3.1	$3.9

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Segment	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	0	30	27.0	$359.8	$90,309	$2.3	$401.09	2	24	21.2	$276.7	$86,796	$5.3	$347.9
2	4	48	44.0	$3,833.2	$114,097	$21.3	$4,069.7	7	36	32.7	$2,478.2	$98,352	$28.3	$2,785.0
3	0	16	14.7	$10.2	$94,440	$0.2	$11.9	0	16	14.7	$10.2	$94,440	$0.2	$11.9
4	0	20	15.8	$12.3	$94,574	$0.2	$13.9	0	20	15.8	$12.3	$94,574	$0.2	$13.9
5	0	16	12.5	$8.8	$97,879	$0.1	$10.3	0	16	12.5	$8.8	$97,879	$0.1	$10.3
Totals				$4,224.3		$24.1	$4,506.9	9			$2,786.1		$34.1	$3,169.1

Number of years for project 10

Unit Cost (Based on 2011 Costs in Model) = $20.58 per tonne CO_2 | Unit Cost (Based on 2011 Costs in Model) = $14.47 per tonne CO_2

Average Pipeline OD = 44.5 inches | Average Pipeline OD = 33.7 inches

Average Pipeline Cost = $111,435 per inch-mile | Average Pipeline Cost = $97,036 per inch-mile

The candidate network shown in Figure A-10 comprises 41 sources and 26 possible storage well locations. The total volume of the candidate sources is 52 million metric tons. Data for the sources included in the network are shown in Table A-16. This region was setup to compare options for storing CO_2 in North Dakota from Minnesota and North Dakota and to identify optimized capture networks at 17.2 and 25 million tonnes annually for comparison. For the 25.1 million tonne scenarios, a run was performed with a reduced data set in order to achieve a result without triggering a memory error in the SimCCS Gateway computational resources.

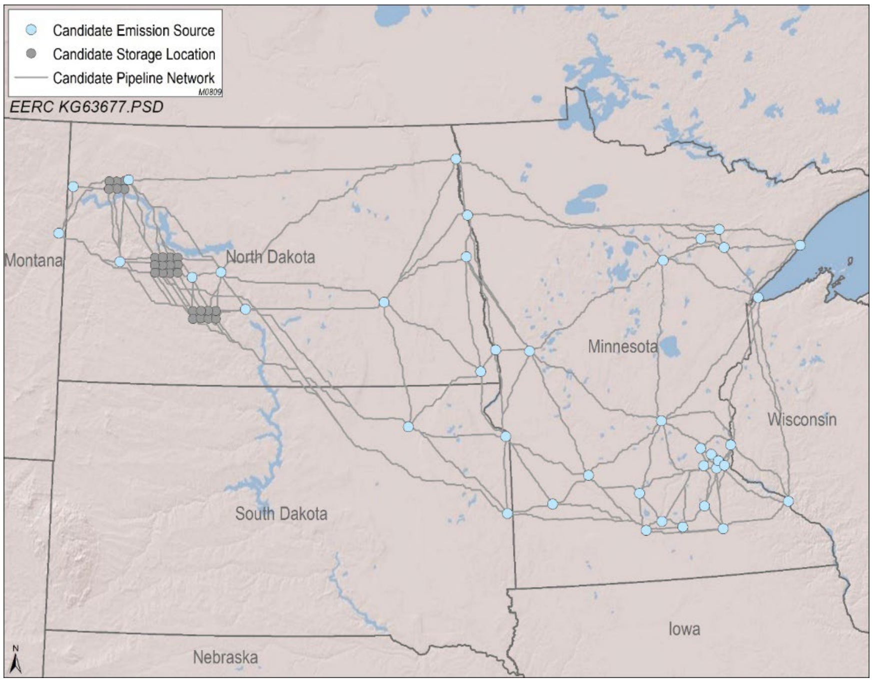

Figure A-10. Candidate network showing optional routes for pipeline connections between North Dakota and Minnesota CO_2 sources greater than 250,000 metric tons annual emission and candidate storage well locations in North Dakota.

Table A-16. Source Data for MN_ND Candidate Network

ID	capMax (MtCO2/y)	N/A	LON	LAT	NAME	Source Type
2150	0.514656	1	-92.91709	43.49951	Absolute Energy, LLC	Ethanol Production
3793	0.524532	1	-93.017379	44.049412	Al Corn Cleen Fuel	Ethanol Production
3794	1.812305	1	-92.7786	45.03	Allen S King	Electric Generating
3798	0.290431	1	-97.006111	47.925833	American Crystal Sugar - E. Grand Forks	Sugar Production
3802	0.322714	1	-95.783525	44.474074	Archer Daniels Midland	Ethanol Production
3803	0.800877	1	-93.2501	44.8108	Black Dog	Electric Generating
3806	5.043888	1	-93.6531	47.2603	Boswell Energy Center	Electric Generating
3819	0.256036	1	-92.9119	44.7956	Cottage Grove Cogeneration	CoGeneration
3829	0.300144	1	-93.2894	44.3353	Faribault Energy Park	Electric Generating
3831	3.946936	1	-93.0406	44.7684	Flint Hills Resources Pine Bend Refinery	Hydrogen Production, Petroleum Refineries
3840	0.627599	1	-93.678611	44.111944	Guardian Energy, LLC	Ethanol Production
3841	0.530706	1	-94.341667	44.541944	Heartland Corn Products	Ethanol Production
3847	0.269598	1	-92.9676	47.478	Hibbing Taconite Company	Iron and Steel Production
3848	1.399021	1	-93.1075	44.9331	High Bridge	Electric Generating
3851	0.362121	1	-96.0428	46.29	Hoot Lake	Electric Generating
3859	0.842875	1	-94.0099	44.1965	Mankato Energy Center	Electric Generating
3871	0.43902	1	-91.26	47.286	Northshore Mining Co - Silver Bay	Iron and Steel Production
3878	0.267114	1	-94.275835	44.100799	Poet Biorefining Lake Crystal, LLC	Ethanol Production
3886	1.175006	1	-93.2753	45.0203	Riverside (1927)	Electric Generating
3891	11.152133	1	-93.8958	45.3792	Sherburne County	Electric Generating
3895	0.478294	1	-95.170752	44.797076	Southern Minnesota Beet Sugar Cooperative	Sugar Production
3898	0.868852	1	-93.002139	44.850583	St. Paul Park Refining Company, LLC	Petroleum Refineries
3902	0.441265	1	-92.5735	47.3502	United Taconite LLC - Fairlane Plant	Iron and Steel Production
3905	1.22728	1	-92.6328	47.565	US Steel - Minntac	Iron and Steel Production
4124	0.35004	1	-104.1569	47.6788	Lewis & Clark	Electric Generating
4237	0.411728	1	-97.0625	47.435833	American Crystal Sugar Co - Hillsboro	Sugar Production
4238	0.33158	1	-97.175	48.591667	American Crystal Sugar Co - Drayton	Sugar Production
4253	2.297384	1	-101.8139	47.2217	Coyote	Electric Generating
4259	0.638276	1	-96.886775	46.073186	Hankinson Renewable Energy, LLC	Ethanol Production
4260	0.302775	1	-102.97899	48.346562	Hess Corporation - 395 - Williston Basin Gath & Boostn	Petroleum & Natural Gas
4266	4.117261	1	-101.3194	47.2819	Leland Olds	Electric Generating
4269	0.665872	1	-100.88083	46.85055	Marathon Mandan Refinery	Petroleum Refineries
4274	0.367341	1	-96.61592	46.323539	Minn Dak Farmers Cooperative	Sugar Production / Agricultural Processing
4288	0.267533	1	-103.950951	48.233527	Pioneer Generating Station	Electric Generating
4294	0.392776	1	-98.5	46.925	Spiritwood Station	Electric Generating
4304	1.399517	1	-103.07779	47.37656	Williston Basin (Petro-Hunt, LLC)	Natural Gas Transmission/Compression
6581	2.812164	1	-96.5103	45.3047	Big Stone	Electric Generating
6583	0.376646	1	-96.5333	44.3961	Deer Creek Station	Electric Generating
6596	0.376825	1	-96.511361	45.301333	Poet Biorefining-Big Stone	Ethanol Production
8199	1.246949	1	-91.2333	43.5592	Genoa	Electric Generating
8210	1.753066	1	-91.9126	44.3026	J P Madgett	Electric Generating

Figure A-11 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 16.83 million tonnes/year (33% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified three sources to generate the target 16.83 million tonnes of CO_2 annually, with those sources storing into four wells. Table A-17 lists the source and storage data for Figure A-11. Table A-18 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without pumping. SimCCS Gateway produced resulting costs of $44.43, $3.17, and $7.63 per metric ton of CO_2 for capture, transport, and storage, respectively, for a total cost of $55.23/ton CO_2.

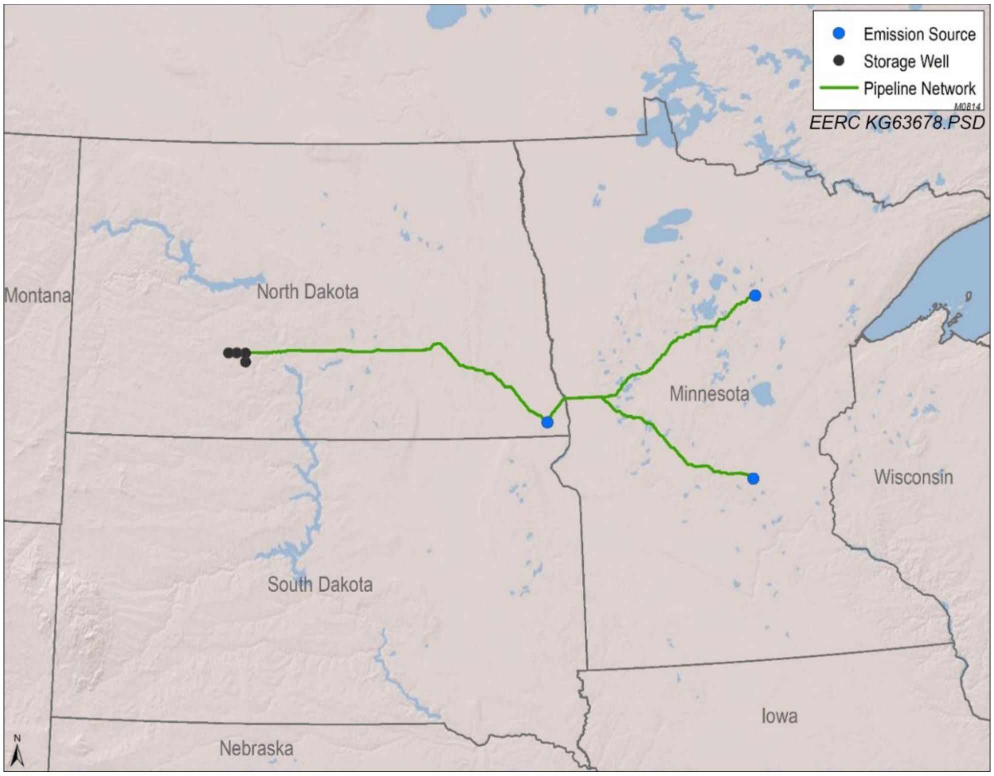

Figure A-11. Source, storage, and pipeline network for MN_ND_33P scenario.

Table A-17. Listing of Source and Storage for MN_ND_33P Edges Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
3806	Boswell Energy Center	-93.6531	47.2603	5.04
3891	Sherburne County	-93.8958	45.3792	11.15
4259	Hankinson Renewable Energy, LLC	-96.886775	46.073186	0.63
149439	Sink 5	-101.3900854	46.73668527	4
149440	Sink 6	-101.3923834	46.82663753	5.5
149424	Sink 7	-101.5234024	46.82501134	5.5
149408	Sink 8	-101.6544141	46.82323904	1.83

Table A-18. Summary of Pipeline Segments for MN_ND_33P Scenario

ND_MN_16.8 Mt

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Segment	Start	End	Elevations Start	Elevations End	Flow Mt/yr	Flow MMSCFD	Pressures Inlet	Pressures Outlet	Length kM	Length Miles	Cost of Pump Stations for System Capital	Cost of Pump Stations for System Operating	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	3806	Fergus Falls, MN	1289	1181	5.04	261.9	2,000	1,500	238.7	148.3	$1.2	$0.5	0	20	17.6	$234.2	$78,965	$2.6	$266.50	2	16	14.4	$182.9	$77,076	$3.7	$226.0
2	3891	Fergus Falls, MN	925	1181	11.15	579.0	2,000	1,500	218.9	136.0	$2.5	$1.2	0	30	23.9	$401.6	$98,417	$2.6	$441.7	3	20	18.4	$222.5	$81,793	$5.9	$296.4
3	Fergus Falls, MN	Wahpeton, ND	1181	965	16.20	840.9	2,000	1,500	46.5	28.9	$3.6	$1.7	0	24	19.8	$60.5	$87,147	$0.5	$86.9	0	24	19.8	$60.5	$87,147	$0.5	$86.9
4	Whapeton, ND	4259	965	1070	16.20	840.9	2,000	1,500	32.8	20.4	$3.6	$1.7	0	24	19.4	$43.3	$88,586	$0.4	$68.3	0	24	19.4	$43.3	$88,586	$0.4	$68.3
5	4259	Spiritwood, ND	1070	1480	16.83	873.8	2,000	1,500	173.4	107.7	$3.8	$1.8	0	36	28.7	$377.9	$97,447	$1.9	$418.5	2	24	22.1	$227.2	$87,871	$5.5	$303.8
6	Spiritwood, ND	Mandan, ND	1480	1647	16.83	873.8	1,900	1,500	174.7	108.6	$3.8	$1.8	0	30	27.5	$294.6	$90,450	$1.9	$335.4	0	30	27.5	$294.6	$90,450	$1.9	$335.4
7	Mandan, ND	Sink6	1647	1925	16.83	873.8	2,000	1,900	20.6	12.8			0	30	23.9	$36.6	$95,154	$0.3	$39.3	0	30	23.9	$36.6	$95,154	$0.3	$39.3
8	Sink 6	Sink 5	1925	2013	4.00	207.7	1,800	1,800	10.2	6.3			0	12	11.2	$7.5	$98,756	$0.2	$9.1	0	12	11.2	$7.5	$98,756	$0.2	$9.1
9	Sink 6	Sink 7	1925	2341	7.33	380.6	1,800	1,600	10.1	6.3			0	20	17.3	$11.9	$94,710	$0.2	$13.6	0	20	17.3	$11.9	$94,710	$0.2	$13.6
10	Sink 7	Sink 8	2341	2036	1.83	95.0	1,600	1,500	8.9	5.5	$0.4	$0.2	0	16	13.1	$9.6	$109,167	$0.2	$13.3	0	16	13.1	$9.6	$109,167	$0.2	$13.3
	Totals				**16.8**			**7**		**580.9**	**$18.8**	**$9.0**				**$1,477.8**		**$10.6**	**$1,692.5**	7			**$1,096.7**		**$18.7**	**$1,392.1**

Number of years for project **10**

Unit Cost (Based on 2011 Costs in Model) = **$10.06** **per tonne CO_2**

Average Pipeline OD = **27.6** **inches**

Average Pipeline Cost = **$92,133** **per inch-mile**

Unit Cost (Based on 2011 Costs in Model) = **$8.27** **per tonne CO_2**

Average Pipeline OD = **22.0** **inches**

Average Pipeline Cost = **$85,719** **per inch-mile**

The candidate network shown in Figure A-12 comprises nine sources and seven possible storage well locations. This candidate network was identified from a subset of wells in the Figure A-12 dataset and reduced from 66% of the 52 million tonne total network CO_2 capacity to 50% in order to get it to calculate through SimCCS Gateway without a memory error. This region was setup to compare options for storing CO_2 in North Dakota from Minnesota and North Dakota and to identify optimized capture networks at 25.75 million tonnes annually.

Figure A-12. Candidate network for MN-ND medium 25.75-Mt scenario.

Figure A-13 shows the network identified by SimCCS Gateway for capturing, transporting, and storing 25.75 million tonnes/year (50% of candidate network) over a 10-year period with a capital recovery rate of 10%. SimCCS Gateway identified nine sources to generate the target 25.75 million tonnes of CO_2 annually, with those sources storing into five wells. Table A-19 lists the source and storage data for Figure A-13. Table A-20 lists pipeline costing information using the FE/NETL CO_2 Transport Cost Model with and without pumping. SimCCS Gateway produced resulting costs of \$52.50, \$2.23, and \$7.52 per metric ton CO_2 for capture, transport, and storage, respectively, for a total cost of \$62.25/ton CO_2.

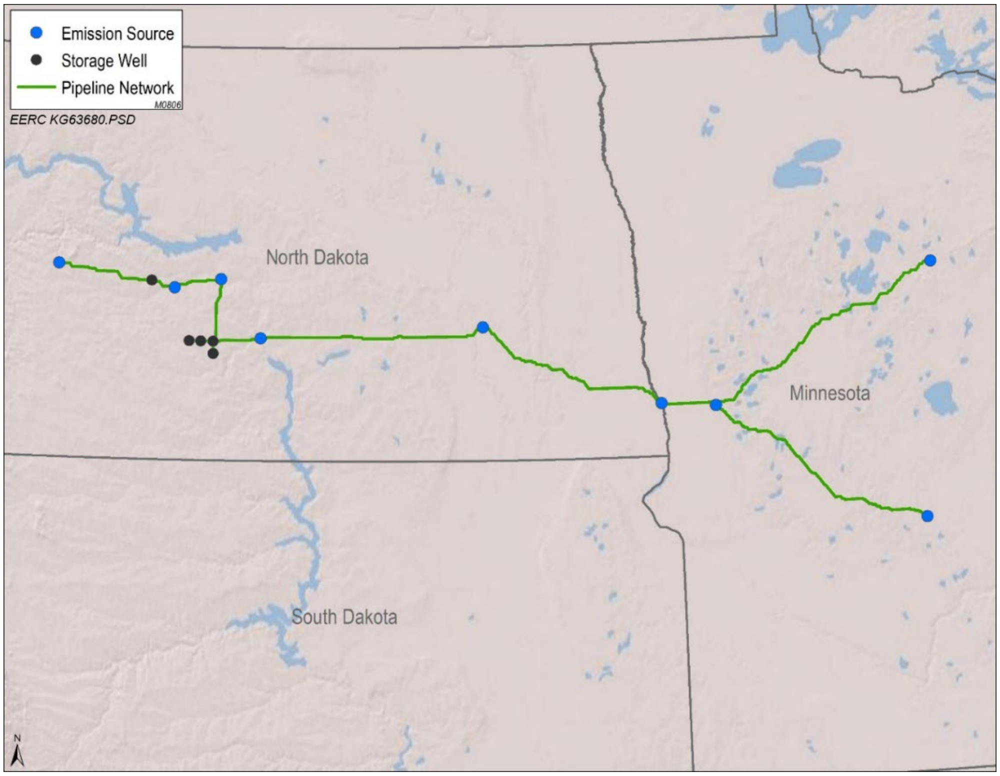

Figure A-13. Source, storage, and pipeline network for MN_ND_MED 25.75-Mt scenario.

TableA-19. Listing of Sources and Storage for MN_ND_MED 25.75-Mt Scenario

ID	Name	Longitude	Lattitude	Flow (Mt/yr)
3806	Boswell Energy Center	-93.6531	47.2603	5.04
3891	Sherburne County	-93.8958	45.3792	6.11
3851	Hoot Lake	-96.0428	46.29	5.36
4274	Minn Dak Farmers Cooperative	-96.61592	46.323539	0.37
4294	Spiritwood Station	-98.5	46.925	0.39
4269	Marathon Mandan Refinery	-100.88083	46.85055	0.67
4266	Leland Olds	-101.3194	47.2819	4.60
4253	Coyote	-101.8139	47.2217	1.82
4304	Williston Basin (Petro-Hunt, LLC)	-103.07779	47.37656	1.40
149439	Sink 1	-101.3900854	46.73668527	5.5
149440	Sink 2	-101.3923834	46.82663753	5.5
149424	Sink 3	-101.5234024	46.82501134	5.5
149408	Sink 5	-101.6544141	46.82323904	5.5
149368	Sink 6	-102.0645183	47.26670574	3.75

Table A-20. Summary of Pipeline Segments for MN_ND_MED 25.75-Mt Scenario

ND_MN_MED 25.1 Mt

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Segment	Start	End	Elevations Start	Elevations End	Flow Mt/yr	Flow MMSCFD	Pressures Inlet	Pressures Outlet	Length kM	Length Miles	Cost of Pump Stations for System Capital	Cost of Pump Stations for System Operating	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$	Number of Pump Stations on PL Segment	PL OD Inch	PL ID Inch	PL Cost MM$	PL Cost $/in-mile	PL Op Cost MM$	10 yr total - Capex and Op Ex MM$
1	3806	3891	1289	1181	5.04	261.9	2,000	1,500	238.7	148.3	$1.2	$0.5	0	20	17.6	$234.2	$78,965	$2.6	$266.50	2	16	14.4	$182.9	$77,076	$3.7	$226.0
2	3891	3851	925	1181	11.15	579.0	2,000	1,500	218.9	136.0	$2.5	$1.2	0	30	24.9	$368.4	$90,297	$2.4	$406.5	3	20	18.4	$222.5	$81,793	$5.9	$296.4
3	3851	4274	1181	965	16.51	857.2	2,000	1,850	46.5	28.9			0	30	23.6	$80.0	$92,155	$0.5	$85.4	1	24	21.4	$61.6	$88,804	$1.1	$72.3
4	4274	4294	965	1480	16.88	876.2	1,850	1,500	179.1	111.3	$3.8	$1.8	0	36	33.5	$390.5	$97,474	$1.9	$431.9	3	24	22.7	$235.0	$87,984	$5.8	$314.6
5	4294	4269	1480	1647	17.27	896.6	2,000	1,500	159.1	98.8	$3.8	$1.9	0	30	27.3	$268.2	$90,461	$1.7	$307.9	0	30	27.3	$268.2	$90,461	$1.7	$307.9
6	4269	Sink 2	1647	2196	17.27	896.6	2,000	1,500	40.1	24.9	$3.8	$1.9	0	24	22.5	$52.4	$87,563	$0.5	$79.5	0	24	22.5	$52.4	$87,563	$0.5	$79.5
7	Sink 2	Sink 1	2196	2267	5.50	285.5	2,000	1,900	10.2	6.3			0	16	14.1	$9.6	$95,062	$0.2	$11.2	0	16	14.1	$9.6	$95,062	$0.2	$11.2
8	Sink 2	Sink 3	2196	2085	11.00	571.1	2,000	1,900	10.1	6.3			0	20	16.4	$11.9	$94,710	$0.2	$13.6	0	20	16.4	$11.9	$94,710	$0.2	$13.6
9	Sink 3	Sink 5	2085	2013	5.50	285.5	1,900	1,800	8.9	5.5			0	16	12.5	$8.7	$98,257	$0.1	$10.1	0	16	12.5	$8.7	$98,257	$0.1	$10.1
10	4266	Sink 2	1703	2196	4.06	211.0	2,000	1,500	54.7	34.0	$1.4	$0.6	0	24	21.2	$688.9	$845,029	$5.8	$754.7	3	16	15.1	$414.1	$761,939	$7.1	$493.1
11	4266	4253	1785	1703	0.53	27.6	2,000	1,500	35.6	22.1	$0.2	$0.1	0	6	5.2	$15.5	$116,959	$0.4	$20.6	0	6	5.2	$15.5	$116,959	$0.4	$20.6
12	4253	Sink 6	1785	1926	2.35	122.0	2,000	1,800	21.8	13.6			0	10	8.6	$12.5	$92,550	$0.3	$15.4	0	10	8.6	$12.5	$92,550	$0.3	$15.4
13	4304	Sink 6	2661	1926	1.40	72.7	2,000	1,500	82.2	51.1	$0.4	$0.2	0	10	8.2	$41.6	$81,527	$0.9	$52.8	1	8	7.4	$37.5	$91,899	$1.1	$50.2
	Totals				25.1			8		687.1	$17.2	$8.1				$2,182.5		$17.5	$2,456.1	13			$1,532.6		$28.0	$1,911.1

Number of years for project 10

Unit Cost (Based on 2011 Costs in Model) = $9.79 per tonne CO2

Average Pipeline OD = 25.3 inches

Average Pipeline Cost = $125,484 per inch-mile

Unit Cost (Based on 2011 Costs in Model) = $7.62 per tonne CO2

Average Pipeline OD = 19.7 inches

Average Pipeline Cost = $113,046 per inch-mile