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ACRONYMS AND ABBREVIATIONS

2D	Two dimensional	in	Inch
3D	Three dimensional	IRROE	Internal rate of return on equity
AoR	Area of review	km	Kilometer
CCS	Carbon capture and storage	mD	Millidarcy
CO ₂	Carbon dioxide	mi ²	Square mile
CO ₂ _S_COM	FECM/NETL CO ₂ Saline Storage Cost Model	Mt	Megatonne (million metric tons)
CO ₂ _T_COM	FECM/NETL CO ₂ Transport Cost Model	MW	Megawatt
DOE	Department of Energy	NETL	National Energy Technology Laboratory
EIA	Energy Information Administration	O&M	Operation and maintenance
EPA	Environmental Protection Agency	PISC	Post-injection site care
FECM	Fossil Energy and Carbon Management	psia	Pound per square inch absolute
ft	Foot, feet	psig	Pound per square inch gauge
FYBE	First-year break-even	T&S	Transport and storage
GDP	Gross domestic product	tonne	Metric ton (1,000 kilograms)
Gt	Gigatonne (billion metric tons)	U.S.	United States
		yr	Year

EXECUTIVE SUMMARY

The National Energy Technology Laboratory (NETL) conducts multiple types of energy system studies on the costs associated with the capture of carbon dioxide (CO₂) from electric power plants and industrial sources. These studies leverage comparative costs for CO₂ pipeline transport and geologic storage (T&S) for handling the equivalent volumes of CO₂ captured. This T&S Quality Guideline for Energy Systems Studies (QGESS) explains the modeling approaches and key assumptions used by NETL to estimate comparable transport, storage, and combined T&S costs in a transparent and reproducible way. This guideline provides representative transport, storage, and combined T&S costs for different scenarios, varying important T&S cost drivers, which can ultimately be used across a range of energy systems studies and reports.

Transport, storage, and combined T&S costs are reported in this guideline as first-year break even (FYBE) costs in real 2023 dollars per metric ton (tonne) (2023\$/tonne). These FYBE costs are from the perspective of a CO₂ pipeline project owner and/or a CO₂ saline storage project owner, and represent a minimum price the owner(s) can charge a CO₂ capture project owner over 30 operating years to transport and/or store a tonne of CO₂ and remain economically viable.

Two tools, developed by NETL and the Department of Energy (DOE) Office of Fossil Energy and Carbon Management (FECM) were used calculate T&S costs: 1) the FECM/NETL CO₂ Transport Cost Model (CO₂_T_COM) and 2) an updated version of the FECM/NETL CO₂ Saline Storage Cost Model (CO₂_S_COM). Both CO₂_T_COM and CO₂_S_COM are publicly available and can be modified to reflect assumptions listed throughout this guidance document.

Six case studies were conducted to generate T&S costs under several modeling scenarios to provide demonstrable example applications. Two case studies were specific to generating transport costs, three were specific to generating storage costs, and one generated combined T&S costs. Three of the case studies focused on the impacts of regional variation, and these compared costs for identical projects located in four different geographic "Guideline Regions": 1) Midwest; 2) Texas; 3) North Dakota; and 4) Montana. These regions align with defined transportation regions for specific pipeline construction labor and pipeline operations and maintenance costs, with defined geologic basins of varying well construction material costs, and variable geologic constitution. Case studies that focused at the project level all assumed projects located within the Midwest region.

The two transportation case studies evaluated the differences in CO₂ pipeline transportation cost between regions as well as on the influence of CO₂ mass flow rate and transport distance on transport cost. At the regional level, the transport regions corresponding with North Dakota and Montana had lower relative transportation costs, while the transport regions corresponding with the Midwest and Texas had higher relative transportation costs. At the project-level, higher CO₂ mass flow rates, and shorter transportation distances result in reduced per tonne transport costs.

The three storage case studies were conducted for evaluating the impact of key CO₂ storage cost drivers on CO₂ storage costs. One case study was regional and more broadly focused, evaluating

how prospective CO₂ storage resource quality and quantity within and across the different basins modeled impacted associated CO₂ storage costs. The other two case studies were focused on the individual storage project-level and included evaluating the effect of storage project design and the effect of annual CO₂ mass flow rates on storage costs. At the regional level, the basins corresponding with the Midwest and Texas regions had lower overall storage costs over a range of cumulative prospective CO₂ storage resource thresholds (5 to 50 billion tonnes [gigatonnes; Gt]), while the basins corresponding with the North Dakota and Montana regions had higher storage costs. At the storage project-level, formations with better reservoir quality (i.e., having more accessible storage space due to geologic reservoir factors like thickness, porosity, permeability, and storage coefficient), lower project activity costs, shorter project phase durations, and higher annual CO₂ mass flow injection rates all resulted in reduced per tonne storage costs.

The combined regional T&S case study aggregated results from the regional transport case study and the regional storage case study to demonstrate the impact of geographic location on combined T&S costs. A single comparable T&S cost in each region was generated for a specific scenario representative of a commercial scale carbon management project. These comparable aggregated T&S costs are referred to as “Guideline T&S Costs”. Guideline T&S Costs are based on a scenario where an average of 4.31 million tonnes (megatonnes [Mt]) of CO₂ are captured each year from a stationary point source and transported along a dedicated greenfield 100-kilometer (62-mile) pipeline to a greenfield CO₂ saline storage site. The scenario assumes that multiple saline storage projects of equivalent size are deployed in each region such that each region will cumulatively store 5 Gt of CO₂ over 30 years. The 5 Gt threshold was chosen to make Guideline T&S Costs’ storage costs be analogous to nth-of-a-kind CO₂ storage project costs that may be more likely as commercial CO₂ storage industry becomes established, as opposed to pilot-scale first-of-a-kind projects which may have distorted storage costs. The Guideline T&S Costs’ storage costs are the highest-cost storage project among the low-cost storage projects needed to exceed the 5 Gt threshold in a particular region, and are shown in Exhibit ES-0-1.

Exhibit ES-0-1. Guideline T&S Costs

Guideline Region	Transportation Region	Geologic Storage Basin	Guideline T&S Costs (2023\$/tonne)
Midwest	Great Lakes	Illinois	10.00
Texas	Southwest	East Texas	10.34
North Dakota	Great Plains	Williston	12.17
Montana	Rocky Mountain	Powder River	16.48

Variability in Guideline T&S Costs between the four selected regions reflect the unique geology of the different storage reservoirs in each associated basin, as well as regional variations in capital costs associated with drilling materials and labor (for storage) and pipeline materials and construction labor (for transportation).

1 INTRODUCTION

Driving down carbon emissions requires dramatic expansion in the scale of deployment of different supporting technologies recognized as a pivotal towards aiding the transition to a low- or zero-emission future. Carbon dioxide (CO₂) capture, transportation, and storage (CCS) receives significant attention by government, academic, and industry stakeholders towards this pursuit as of late. CCS includes a collection of technologies aimed to lessen the volume of CO₂ emitted to the atmosphere from various industrial or power generating sources or to remove CO₂ from the air directly. The collection involves a sequence of integrated components, which collectively defines the CCS value chain. Necessary components include 1) separating and capturing CO₂ from industrial and fossil-fuel power generation sources or directly from the air, purifying the CO₂ stream as needed, and compressing it for transport; 2) transporting the CO₂ to a geologic storage or utilization site, which can occur onshore via pipeline; and 3) injecting the delivered CO₂ into a suitable geologic storage formation where the CO₂ can be isolated from the atmosphere [1, 2].

Advancing CCS requires analytical capability that can provide quantitative outlooks associated with the cost and economics of CCS where technical requirements intersect current regulations and cost drivers. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) and Office of Fossil Energy and Carbon Management has developed models and methods that enable cost and economic evaluation of each component of the CCS value chain or CCS as an integrated whole [3]. The publicly available FECM/NETL CO₂ Transport Cost Model (CO₂_T_COM)^a and an updated version of the publicly available FECM/NETL CO₂ Saline Storage Cost Model (CO₂_S_COM)^b were developed to assess at the screening level cost and performance of pipelines for CO₂ transportation and saline reservoirs for CO₂ storage, respectively. These models are flexible and enable evaluation across a broad spectrum of integrated CCS scenarios [4, 5, 6, 7], and they can be used to focus on evaluating particular cost drivers associated with CO₂ transport and/or storage [8, 9, 10]. Therefore, these models are effective when used to perform comparative analyses of the impacts of specific technologies or activities on overall transport or storage project costs. However, both the CO₂_S_COM and CO₂_T_COM are intrinsically complex. They each incorporate a multitude of user inputs and have many underlying factors to effectively evaluate CO₂ transport and storage (T&S) projects and offer users effective decision support capability. Thus, it remains important to explain the modeling approaches and key assumptions used by NETL to estimate comparable T&S costs in a transparent and reproducible way.

The purpose of this guideline is to provide an overview of the modeling approaches used by the NETL to estimate costs for transport, storage, and combined T&S. These cost estimation methods can be used by across various energy systems studies, reports by NETL and DOE, as well as by other stakeholders interested in evaluating technical and cost considerations for CO₂

^a The model is available on NETL's website [12, 33].

^b It is important to note that a version of CO₂_S_COM that is under development was used for this analysis. This version will eventually be released to the public. However, an earlier version of the model is available on NETL's website [34, 35].

capture, transport, and storage systems. This guideline provides representative transport, storage, and combined T&S costs for a variety of situational case studies to demonstrate application. This guideline also discusses key cost drivers and how they affect overall transport, storage, and combined T&S costs.

Transport, storage, and combined T&S costs are reported in this guideline as first-year break even (FYBE) costs in real 2023 dollars per metric ton (tonne) (2023\$/tonne). These FYBE costs are from the perspective of a CO₂ pipeline project owner and/or a CO₂ saline storage project owner, and represent a minimum price the owner(s) can charge a CO₂ capture project owner over 30 operating years to transport and/or store a tonne of CO₂ and remain economically viable.

2 MODELING APPROACH

NETL uses CO₂_T_COM and CO₂_S_COM to estimate the costs of CO₂ pipeline transport and CO₂ saline storage, respectively. CO₂_S_COM and CO₂_T_COM were designed to be able to incorporate a multitude of user inputs, enabling the flexibility needed to evaluate carbon management costs across a broad spectrum of integrated CCS scenarios [4, 5, 6, 7]. The large variety of user input options enable the tools to be used for focused evaluation on particular cost drivers associated with CO₂ transport and/or storage. Examples have been demonstrated by Vikara et al. (2018), Warner et al. (2020), and Morgan et al. (2023) [8, 9, 10]. This section explains the modeling approaches and details key assumptions used by NETL to estimate the comparable transport, storage, and combined T&S costs from six case studies in a transparent and reproducible way.

All the case studies and associated transport, storage, and combined T&S costs reported in this guideline share a common assumption about capture, transport, and storage project interconnectivity. The case studies all assume a single CO₂ pipeline transport project transports CO₂ to a single CO₂ storage project, and that both projects are designed and sized to manage the annual CO₂ mass flow rate of a single CO₂ point source engaged in CO₂ capture. A key assumption shared across both CO₂_T_COM and CO₂_S_COM methodologies is the alignment of the projects’ operational start dates. An idealized timeline for the construction and operation of a capture plant, pipeline, and storage site is shown in Exhibit 2-1, along with key development stages outlined for each.

Exhibit 2-1. Idealized timeline for construction and operations of capture pipeline, and storage projects

Year	1	2	3	4	5	6	7	...	34	35	36	...	84	85
Capture Plant		Capital Expenditure Period: 3–5 Years				Operations: 30 Years								
Pipeline			Capital Expenditure Period: 3 Years			Operations: 30 Years								
Storage Site: Base Case	Site Screening	Site Selection and Site Characterization		Permitting and Construction		Operations: 30 Years						PISC and Site Closure: 50 Years		

In both the CO₂_T_COM and CO₂_S_COM, the transport and storage projects' start year (not the operations phase start year as shown in Exhibit 2-1) for cost estimates performed in this guideline was assumed to be 2023, to align with T&S costs being reported as first-year [of project] break even real 2023 dollars per tonne of CO₂. The rest of the assumptions within the case studies vary in different ways, and are described in the following sections:

- Section 2.1 describes the CO₂_T_COM and its key underlying factors. Section 2.1 also outlines key financial and project design assumptions and model settings NETL used to generate comparable CO₂ transport costs reported in the two transport cost case studies presented in this guideline.
- Section 2.2 describes the CO₂_S_COM and its key underlying factors. Section 2.2 also outlines key financial and project design assumptions and model settings NETL used to generate comparable CO₂ storage costs reported in three storage cost case studies presented in this guideline.
- Section 2.3 describes the assumptions used to select regional transport and regional storage case studies' cost results to generate comparable combined T&S costs, termed "Guideline T&S Costs".

2.1 TRANSPORT COST OVERVIEW AND METHODS

NETL estimates CO₂ transport costs using the CO₂_T_COM. CO₂_T_COM is a Microsoft® Excel-based model that estimates the cost of transporting liquid CO₂ via pipeline [12] connecting point-to-point the CO₂ source with the CO₂ storage site. CO₂_T_COM includes the capital costs for purchasing and installing the pipeline, a surge tank, a pipeline control system, and, if required, booster pumps along the pipeline to boost the pressure. The model accounts for the operation and maintenance (O&M) costs for the pipeline and pumps and the cost of the electricity used to power the pumps. CO₂_T_COM also has a financial module that accounts for depreciation and taxes and uses the weighted average cost of capital to discount net earnings and account for the costs of debt and equity.

One major assumption in the CO₂_T_COM is that the owner (also assumed to be the operator) of the CO₂ pipeline is an independent profit-seeking entity that charges a user for transporting CO₂. The pipeline operator sets a price for transporting CO₂ in dollars per tonne of CO₂. This price results in revenues for the pipeline operator and these revenues are used to offset costs, including capital costs, operating and maintenance (O&M) costs, taxes and financing costs (principal and interest on debt and the minimum desired internal rate of return on equity) to build and operate the pipeline. An important output from CO₂_T_COM is the FYBE CO₂ transport price which is the CO₂ price that makes the net present value for the project equal to zero. The FYBE price is the lowest price the pipeline operator can charge for transporting CO₂ and still have a viable project, if just barely. The FYBE CO₂ price of transportation from the pipeline operator's perspective is also the FYBE CO₂ cost of transportation from the capture facility's perspective. In this analysis, the terms FYBE CO₂ cost and FYBE cost are used, and these are the same as the FYBE CO₂ price.

CO₂_T_COM assumes that CO₂ is provided to the pipeline by the CO₂ source at a pressure of 2,200 pounds per square inch gauge (psig), and the cost and energy requirements of compression are provided by the CO₂ source. The model assumes that CO₂ is provided by the source at the pipeline operator's specifications for purity. The model also assumes that CO₂ is transported as a liquid since temperatures in the ground that surround a buried pipeline are not high enough to support CO₂ in the supercritical phase.

CO₂_T_COM assumes that CO₂ exits the pipeline terminus at the CO₂ storage site at a pressure of 1,200 psig to ensure that CO₂ remains in a dense phase liquid state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation changes. If the pipeline has booster pumps, the pipeline is assumed to be divided into equal length segments with booster pumps at the end of all segments except the last. Pipeline design in this guideline for all transportation cost estimates assumed a pressure drop of 1,000 psia across the pipeline or pipeline segments if booster pumps were used, as described above. Additional pressure increases that may be required for injection into a storage reservoir are assumed to be provided by pumps owned and operated by the storage project.

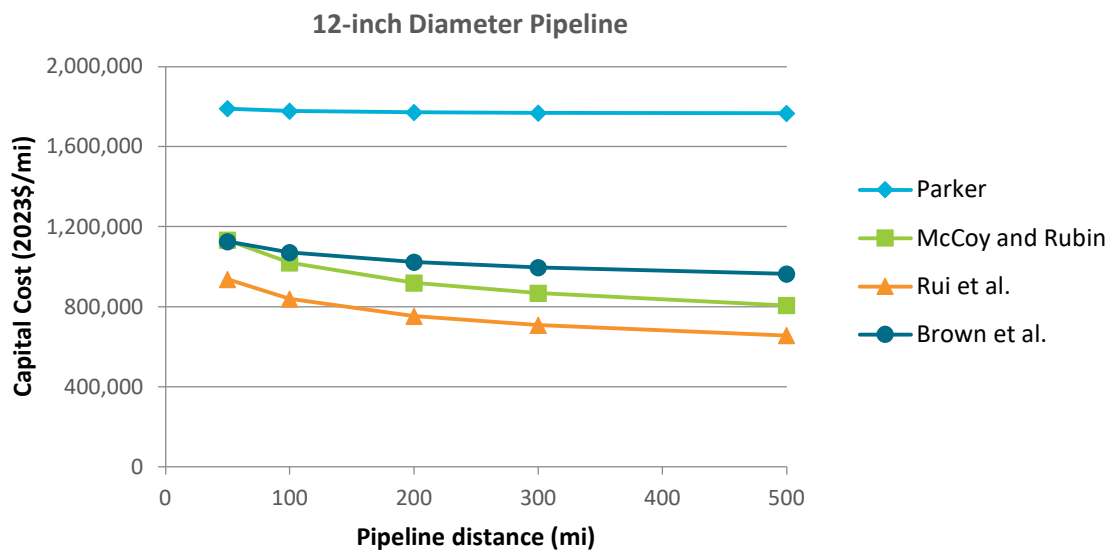
The CO₂_T_COM can estimate the minimum pipeline diameter needed to transport the CO₂ a user-specified distance without any pumps to boost the pressure. The model can also determine if a smaller diameter pipe can be used if one or more pumps are used at equal intervals along the pipeline to boost pressure sufficiently to assure that the outlet pressure is 1,200 psig. It uses an iterative procedure to determine the diameter necessary to sustain a 1,000-pounds per square inch absolute (psia) pressure drop over the specified pipeline length, or pipeline segment length, if pumps are installed along the pipeline. The model rounds up the diameter to the nearest standard pipe diameter. The pipeline diameter is determined based on the maximum CO₂ mass flow rather than the average annual CO₂ mass flow rate.

The CO₂_T_COM provides the option to use one of four sets of regression equations based on natural gas pipelines to calculate the capital costs for a CO₂ pipeline. Each regression equation calculates costs for four categories: 1) materials, 2) labor, 3) right-of-way and damages, and 4) miscellaneous. The materials category includes the costs for pipe, pipe coating, and cathodic protection. The labor category and right-of-way and damages category are self-explanatory. The miscellaneous category includes costs for surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overhead, and regulatory filing fees. The costs for each category are compiled by the Federal Energy Regulatory Commission for inter-state natural gas pipelines and these costs are published annually. One set of regression equations for pipeline capital costs was developed by Parker (2004) [13] using cost data from 1991 to 2003; these equations provide costs in 2000 dollars. A second set of regression equations was developed by McCoy and Rubin (2008) [14] using cost data from 1995 to 2005; these equations provide costs in 2004 dollars. The third set of regression equations for pipeline capital costs was developed by Rui et al. (2011) [15] using cost data from 1992 to 2008; these equations provide costs in 2008 dollars. The fourth set of regression equations was developed by Brown et al. (2022) [16] using cost data from 1980 to 2017; these equations provide costs in 2018 dollars.

While the four sets of regression equations have different functional forms, they all calculate natural gas pipeline capital costs as a function of pipeline length and diameter. The cost equations by McCoy and Rubin, Rui et al., and Brown et al., also considered regional cost differences, whereas cost equations by Parker were based on national data. Thus, the capital costs for pipelines (using equations other than Parker) with identical length and diameter will not be the same if they are in different defined regions. The defined regions are Northeast, Southeast, Midwest, Southwest, Central, and Western for McCoy and Rubin and Rui et al. For Brown et al., the defined regions are New England, Mid-Atlantic, Southeast, Great Lakes, Great Plains, Rocky Mountain, Pacific Northwest, Southwest, and California. The capital costs for all four sets of equations are adjusted (escalated, or de-escalated in the case of Brown et al.) to 2011 dollars in the CO₂_T_COM using a variety of price indices. The resulting capital costs are for natural gas pipelines. CO₂ pipelines operate at higher pressures than natural gas pipelines, so they require a thicker pipe wall, which affects the cost. The capital costs for materials and labor are therefore adjusted, depending on the pipe diameter, in CO₂_T_COM using factors developed by ICF International [17].

The four sets of regression equations for natural gas pipeline capital costs, adjusted for CO₂ pipelines, give different results as illustrated in Exhibit 2-2, which presents the cost per mile data escalated to 2023\$ for 12-inch diameter pipelines of different lengths. The results in Exhibit 2-2 for the Parker equations are national, while the results for McCoy and Rubin and Rui et al., are for the Midwest region, and Brown et al. is for the average costs across all regions in the United States.

Exhibit 2-2. CO₂ pipeline capital costs per mile using CO₂_T_COM's different regression equation options



In general, the equations from Parker give significantly higher costs than the other three sets of regression equations. Brown et al., gave the highest cost of the remaining three, while Rui et

al., gave the lowest costs. Also note that regardless the capital cost regression equation used, capital costs on a per mile basis decrease as the pipeline distance increases, due to economies of scale.

The regression equations from Brown et al., were used in the analysis for this guideline for all transport costs, over those of Parker, McCoy and Rubin and Rui et al., since the Brown et al. regression equations were based on the most recent costs of the four different sets of equations.

The costs for a surge tank and pipeline control system were taken from an earlier NETL study [18]. These costs were in 2000\$ and are adjusted to 2011\$ in the CO2_T_COM using appropriate price indices. The capital costs for a booster pump were determined using an equation provided by McCollum and Ogden (2006) [19]. This equation needs the power requirements for the booster pumps that McCollum and Ogden also provided, which are based on the CO2 mass flow rate and pressure increase through the pump. The pump capital costs were in 2005 dollars and are adjusted to 2011\$ in the model using appropriate price indices.

The O&M costs for the pipeline were assumed to be 2.5 percent of the capital costs on an annual basis [19]. The O&M costs for the remaining pieces of equipment were assumed to be 4 percent of the capital costs on an annual basis. The price of electricity used to estimate the cost of the electricity used by the pumps was assumed to be the national average electricity price for electricity provided to commercial operations in 2011 [20].

As discussed above, the CO2_T_COM has a financial module that accounts for debt, equity, depreciation, and taxes. The model can determine the cost of CO2 (in \$/tonne CO2 transported) that provides investors with their desired minimum internal rate of return on equity (IRROE). To use the financial module, several parameters must be specified. For this guideline’s evaluation, it was assumed that it takes three years to complete the construction of the pipeline and that the pipeline operates for 30 years (as shown in Exhibit 2-1). The financial parameters used in the CO2_T_COM for this guideline’s evaluations are shown in Exhibit 2-3. The model includes a project contingency cost calculated for all capital items. NETL guidelines for cost estimating [21] recommend using a project contingency factor between 15 percent and 30 percent for the budgetary-level type cost estimate that is provided by the CO2_T_COM. The lower factor of 15 percent was used for the analysis in this guideline (Exhibit 2-3) because the pipeline costs provided by the *Oil & Gas Journal* may include contingency and some taxes. Table notes for Exhibit 2-3 provide definitions for the other financial parameters used.

Exhibit 2-3. Financial parameters used in CO2_T_COM

Financial Parameter	Value
Percent equity (remainder is debt) (%) ^A	45
Cost of equity (%/yr) ^A	10.77
Cost of debt (%/yr) ^A	3.91
Tax rate (%/yr) ^B	25.74

Financial Parameter	Value
Escalation rate from base year to project start year (%/yr) ^C	4.8
Escalation factor from base year to project start year (unitless) ^D	1.755
Escalation rate from project start year and beyond (%/yr)	0
Project contingency factor (%)	15

Note: Base year = 2011 and project start year = 2023

^APercent equity, cost of equity, and cost of debt are based on values from the largest natural gas transportation companies. These values are real rates and are based on a 2.30 percent average real gross domestic product (GDP) deflator (1990–2023) [22].

^BTax rate is the effective rate (includes federal and state), which is the average rate a company’s pre-tax profits are taxed [23].

^CCalculated by taking the average of the 2011–2023 percent change over time for the total transmission plant within *The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2023 – Cost Trends of Gas Utility Construction* across the six regions [11].

^DObtained by using the equation $Escalation\ factor = (1 + escalation\ rate\ from\ base\ year\ to\ project\ start\ year)^{(project\ start\ year - base\ year)}$.

Based on user input settings, CO2_T_COM calculates cash flows for revenues, capital costs and O&M costs. These costs are provided initially in constant dollars in the first year of the project and then escalated to nominal dollars based on the assumed escalation rate from project start year and beyond. The nominal capital costs are depreciated and used to calculate taxes. The capital costs, O&M costs, and taxes are subtracted from revenues to give net earnings in nominal dollars. The net earnings are discounted using the weighted average cost of capital to provide discounted or present value net earnings. The present value net earnings are summed to give the net present value or NPV for the project [12]. The model uses the NPV metric to estimate the FYBE to transport a tonne of CO₂. This occurs via iteration on the \$/tonne transport price to achieve an NPV of \$0 or close to \$0.

Two case studies are provided in this guideline to demonstrate how NETL estimates comparable CO₂ transport costs varying different aspects of CO₂ pipeline transportation. The first transportation case study evaluates the impact of regional changes in material and labor costs on transport costs. The second transportation case study evaluates the impact of CO₂ mass flow rate and pipeline distance on transportation cost within a single region. The methodology unique to each transport cost case study are described in the following Sections 2.1.1 and 2.1.2.

2.1.1 Transport Cost Case Study 1: Regional Variation – Methodology

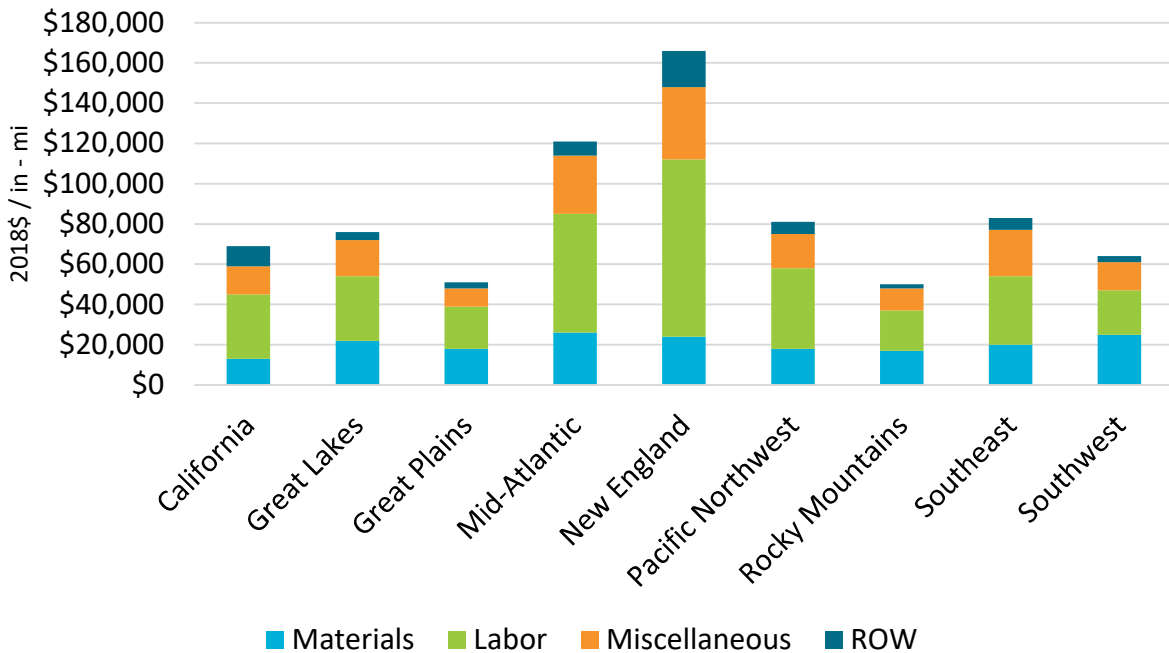
Transport Cost Case Study 1 evaluates the impact of regional variations in pipeline construction and labor costs on CO₂ transportation costs. Four transport regions were selected that align with Brown et al., pipeline cost regression equations in CO2_T_COM: 1) Great Lakes, Southwest; 2) Great Plains; and 3) Rocky Mountains. These transportation regions are geographically delineated, along with the other Brown et al. transportation regions, in Exhibit 2-4.

Exhibit 2-4. Brown et al., transportation regions



Each transport region’s average pipeline costs, normalized by pipeline diameter and pipeline length, are shown in Exhibit 2-5 broken out by costs category (materials, labor, miscellaneous, and rights-of-way) to demonstrate how pipeline costs vary regionally. Exhibit 2-5 costs are derived from Brown et al. [15].

Exhibit 2-5. Brown et al., normalized total pipeline costs broken out by cost category



In each of the four transport regions, CO₂_T_COM was used to estimate the FYBE cost to transport 100 km (62 mi) a maximum daily flow of 13,892 tonnes/day at an 85% capacity factor from a power plant. Capacity factor is the ratio of the average annual CO₂ mass flow rate to the maximum CO₂ mass flow rate converted to an annual basis. A 13,893 tonnes/day maximum CO₂ mass flow rate and an 85% capacity factor is equivalent to an average annual CO₂ mass flow rate of 4.31 million tonnes per year (Mt/yr) of CO₂ captured. The maximum mass flow rate is important in CO₂_T_COM because pipelines must be designed to operate at maximum mass flow rates; however annual revenues are a function of average annual mass flow rate. In each region, a 100-km (62-mi) pipeline was assumed to connect the capture plant directly to a storage project.

Results of Transport Cost Case Study 1 are shown and described later in Section 3.1.1. These regional transport costs are also aggregated with regional CO₂ storage costs, as described in Section 2.3, to provide Regional T&S Costs reported in Section 3.3.

2.1.2 Transport Cost Case Study 2: CO₂ Mass Flow Rate and Pipeline Distance Variations – Methodology

Transport Cost Case Study 2 evaluates the influence of CO₂ mass flow rate and transport distance variations on transport cost. Cost data were calculated for two pipeline lengths (100 km or 62 mi, and 200 km or 124 mi) and two capacity factors (85% and 80%) over maximum daily CO₂ mass flow rates ranging from 4,000 to 20,000 tonnes/day using the average cost from each of the nine Brown et al., transportation regions (shown in Exhibit 2-4). These different scenarios represent a range of possible CO₂ point sources that might be deploy a CO₂ capture project. The Transport Cost Case Study 2 results are generated by averaging the transport cost in each of the nine transport regions for each unique transport scenario; the results are reported in Section 3.1.2.

2.2 STORAGE COST OVERVIEW AND METHODS

Storage costs were estimated for all storage case studies in this guideline using the CO₂_S_COM. The CO₂_S_COM is a Microsoft® Excel-based tool that estimates the FYBE cost for storing CO₂ in a deep saline aquifer. To inject CO₂ into the subsurface for storage in a saline-bearing reservoir, the site owner must comply with the U.S. Environmental Protection Agency (EPA) regulations for Class VI injection wells under EPA's Underground Injection Control Program [24], which is authorized under the Safe Drinking Water Act. The site owner must also comply with monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule [25], which is authorized under the Clean Air Act. The FYBE cost estimated by CO₂_S_COM accounts for the technology needed and associated cost to conduct storage operations in a way that complies with these regulations. The FYBE cost of storage also accounts for all financing costs, including interest and principal on debt and minimum desired return on equity.

Most of the original cost data for wells, technology, and labor in the CO₂_S_COM are from EPA's economic analysis of the Class VI and Subpart RR regulations and are in 2008\$ [26]. When

possible, costs have been updated. For example, the cost to drill and complete all deep wells in the model are based on the 2014 American Petroleum Institute-Joint Association Survey. Some other costs in the model have been updated based on conversations with industry personnel while at conferences.

The publicly available version of CO₂_S_COM has a database with 64 geologic formations from across the contiguous U.S. Each geologic formation in CO₂_S_COM is divided into sub-areas which make up the storage reservoirs. The storage reservoirs were determined by geologists as areas within a geologic formation that have similar geologic properties. Because geologic properties are very heterogeneous, judgment was required to divide each geologic formation into storage reservoirs. Based on the judgment of the geologist, each storage reservoir was assigned geologic properties that are representative of that storage reservoir (such as depth to the top of the storage reservoir, and thickness, porosity and permeability of the storage reservoir). For this guideline, “geologic formation” will be used to define an entire formation (e.g., entire Mount Simon), while “storage reservoir” will be used to identify a sub-area of the geologic formation. The publicly available version of CO₂_S_COM consists of 228 total storage reservoirs [27].

Many of these storage reservoirs were further divided into two or more unique storage reservoirs in the modified version of the CO₂_S_COM used in this guideline. Storage reservoirs that crossed state boundaries were split into one reservoir per state, and storage reservoirs that were especially thick were split into multiple thinner (typically 1000 feet thick) stacked reservoir intervals. Other geologic formations and their associated reservoirs were also added. As a result, the modified version of the CO₂_S_COM used in this guideline used a geologic database which includes geologic properties for 314 storage reservoirs from 88 geologic formations from across the contiguous U.S. For example, the Mount Simon geologic formation is present in three basins (Inter-Basin Arch, Michigan, and Illinois basins), and is present in five states (Illinois, Indiana, Michigan, Ohio, and Kentucky). The Mount Simon is divided into 11 storage reservoirs (named Mount Simon 1, Mount Simon 2, and so forth). For example, The Mount Simon 1, Mount Simon 2, and Mount Simon 3 are located in the Illinois Basin, in the state of Illinois, and are differentiated by depth to the top of the storage reservoir (11,300 feet, 7,240 feet, and 4,270 feet, respectively); the Mount Simon 4, Mount Simon 5, and Mount Simon 6 are similarly located in the Illinois basin, are similarly differentiated by depth, but are located in the state of Indiana.

CO₂_S_COM can calculate the prospective CO₂ storage resource in each storage reservoir assessed. Prospective CO₂ storage resource is the mass of CO₂ that can potentially be stored in a storage reservoir if all the available pore space is utilized [27]. A subsurface reservoir’s prospective CO₂ storage resource is a yet-to-be-proved CO₂ storage capacity. The prospective CO₂ storage resource for each storage reservoir is calculated in CO₂_S_COM assuming pressure interference. Pressure interference is the potential impact on effective prospective CO₂ storage resource that nearby CO₂ storage projects in the same storage reservoir can have on each other [28]. The CO₂_S_COM estimates the impact of pressure interference on prospective CO₂ storage resource based on an approach proposed by Teletzke et al. (2020) [29] that uses the average permeability of the storage reservoir to calculate a factor that reduces the prospective CO₂

storage resource. Accounting for pressure interference reduces the prospective CO₂ storage resource in a given storage reservoir; this reduction, relative to estimates that do not consider pressure interference, can be as much as 94% less in storage reservoirs with relatively low permeability. All storage costs calculated in this guideline assume there is subsurface pressure interference between the multiple projects deployed in the same storage formation.

Another factor that influences costs is the financial responsibility requirements of the Class VI regulations. The financial responsibility aspect requires the CO₂ saline storage operator purchase a financial instrument that will cover the cost of certain aspects of storage. There are four aspects to financial responsibility. The first is the cost of corrective action which is finding legacy wells that were drilled into the storage reservoir, determining if they were properly plugged and abandoned, and plugging and abandoning those that were not properly plugged and abandoned. The second is the cost of plugging and abandoning the injection wells when injection ceases. The third is the cost of post-injection site care (PISC) and site closure. In the Class VI regulations, PISC is the requirement that the storage operator monitor the CO₂ plume and pressures in the storage reservoir until the plume stabilizes and pressures decline to levels considered acceptable to the regulatory authority. The fourth is the cost of implementing an Emergency and Remedial Response (ERR) Plan. An ERR Plan outlines the actions the storage operator will take if fluid leaks out of the storage reservoir and into an underground source of drinking water (USDW). A USDW is defined by the Class VI regulations as any groundwater with salinity less than 10,000 parts per million (ppm). The Class VI regulations define financial instruments that are acceptable for meeting the requirements for financial responsibility. For this analysis, a trust fund was used to cover the first three aspects and an insurance policy was used for the last aspect (i.e., the cost of implementing the ERR Plan).

Financial parameters used/modeled in the CO₂_S_COM for storage cost analyses as part of this guideline are shown in Exhibit 2-6. The CO₂_S_COM includes a project contingency cost calculated for all capital items and a process contingency cost for all monitoring activities. NETL guidelines for cost estimating [21] recommend using a project contingency factor of 15–30 percent for the budgetary-level type cost estimate that is provided by the CO₂_S_COM and a process contingency factor between 20 percent and 35 percent for small, pilot plant data (small, pilot plant storage projects have been completed). The lower factors of 15 percent and 20 percent were used for the project contingency and process contingency, respectively, for the analysis in this guideline (Exhibit 2-6). Notes listed below Exhibit 2-6 provide definitions for the other financial parameters used/modeled.

Exhibit 2-6. Financial parameters used/modeled in CO₂_S_COM

Financial Parameter	Value
Percent equity (remainder is debt) (%) ^A	45
Cost of equity (%/yr) ^A	10.77
Cost of debt (%/yr) ^A	3.91
Tax rate (%/yr) ^B	25.74

Financial Parameter	Value
Escalation rate from base year to project start year (%/yr) ^C	3.5
Escalation factor from base year to project start year (unitless) ^D	1.663
Escalation rate from project start year and beyond (%/yr)	0
Project contingency factor (%)	15
Process contingency factor (%)	20
Financial responsibility instrument	Trust Fund and Insurance
Escalation rate for financial instrument (%/yr) ^E	2.32
Trust Fund growth rate (%/yr)	5

^APercent equity, cost of equity, and cost of debt are based on values from the largest natural gas storage companies. These values are real rates and are based on a 2.30 percent average real GDP deflator (1990–2023) [22].

^BTax rate is the effective tax rate (includes federal and state), which is the average rate a company’s pre-tax profits are taxed [23].

^CCalculated by taking the average of the 2008–2023 percent change over time for the storage plant gas holders found within the *Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2023 – Cost Trends of Gas Utility Construction* across the six regions [11].

^DObtained by using the equation $Escalation\ factor = (1 + escalation\ rate\ from\ base\ year\ to\ project\ start\ year)^{(project\ start\ year - base\ year)}$.

^EAverage real gross domestic product deflator (1990–2023) [22].

Three case studies are provided in this guideline to demonstrate how NETL estimates comparable CO₂ storage costs varying different aspects of CO₂ saline storage. The first storage cost case study evaluates the impact of regional changes in the quality and availability of storage reservoirs on storage costs as cumulative CO₂ storage thresholds increase. The second storage cost case study evaluates the impact of CO₂ storage project design, specifically storage formation geology and storage project execution parameters on storage costs. The third storage cost case study evaluates how variation in annual CO₂ mass flow rate impacts storage cost. The methodology unique to each storage cost case study are described in the following Sections 2.2.1, 2.2.2, and 2.2.3.

2.2.1 Storage Cost Case Study 1: Regional Variation – Methodology

To demonstrate how storage costs vary regionally, CO₂_S_COM was used to estimate storage costs for storage projects in basins associated with the four Brown et al., transport regions selected in Section 2.1.1. In each of the four regions, the storage projects modeled were assumed to inject a maximum daily mass flow rate of 13,892 tonnes/day of CO₂ captured from a CO₂ point source with a capacity factor of 85 percent (equivalent to 4.31 Mt per year on average). For each storage project modeled, financial assumptions were kept the same, as outlined in Exhibit 2-6. Each storage project’s design and geologic assumptions were assumed the base scenario described in the next section’s (Section 2.2.2) Exhibit 2-9.

The four basins assessed for comparison in Storage Cost Case Study 1 are the Illinois Basin (in the Great Lakes region), the East Texas Basin (in the Southwest region), the Williston Basin (in the Great Plains region), and the Powder River Basin (in the Rocky Mountain region) are mapped in Exhibit 2-7. The unique storage reservoirs within the four basins, the reservoir’s

extents, and the geographic centroid of each, are also mapped in color in Exhibit 2-7. These reservoirs are listed by basin in Exhibit 2-8.

Exhibit 2-7. Locations of four basins selected for this analysis

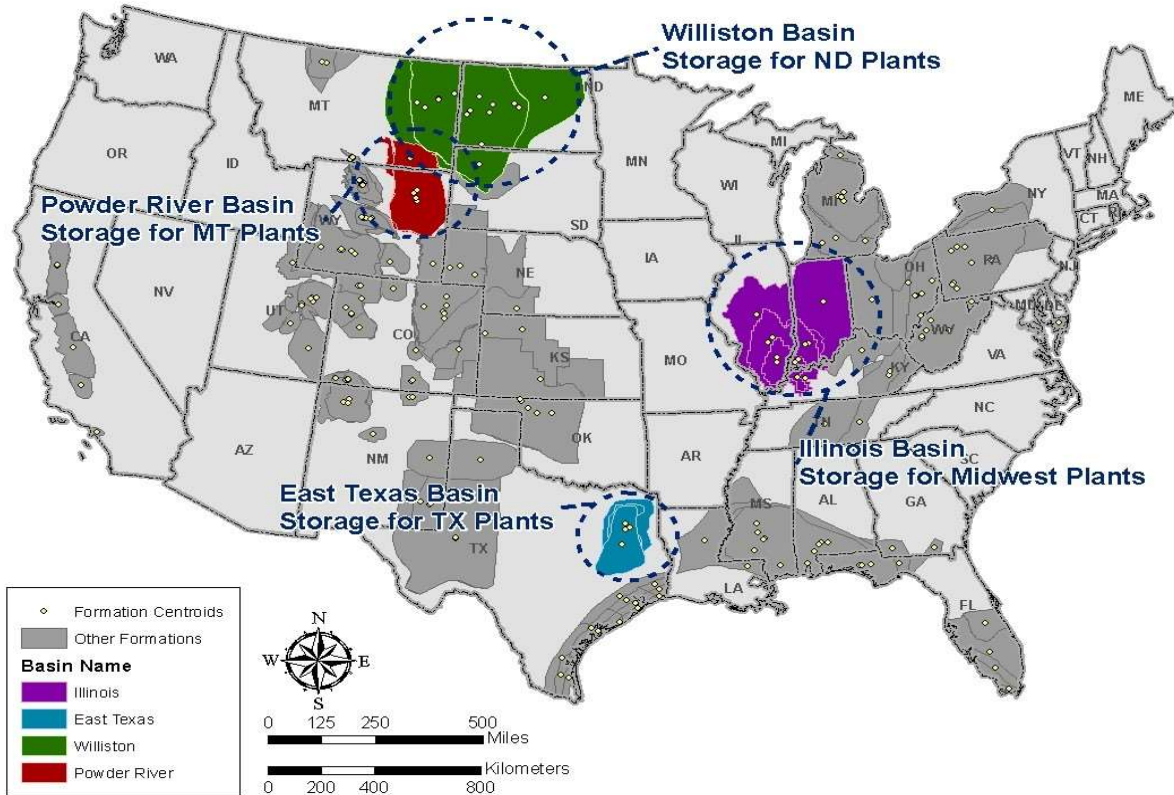


Exhibit 2-8. Regional storage variation case study basins, geologic formations and associated storage reservoirs

Corresponding Transport Region	Geologic Storage Basin	Geologic Formations	Storage Reservoirs in CO ₂ _S_COM Geologic Database
Great Lakes	Illinois	Mount Simon; Saint Peter; Knox	Mount Simon 1, 2, 3, 4, 5, and 6; Saint Peter 1, 2, 3, 4, 5, and 6; Knox 1, 2, 3, 4, 5, and 6
Southwest	East Texas	Woodbine; Paluxy	Woodbine 1; Paluxy 1, 2, and 3
Great Plains	Williston	Basal Cambrian; Broom Creek; Inyan Kara; Madison Group- Mission Canyon; Red River;	Basal Cambrian 2, 3, 4, 5, 6, 7, and 8; Broom Creek 1, 2, and 3 Inyan Kara 1, 2, and 3 Madison Group - Mission Canyon 1, 2, 3, and 4; Red River 1 and 2;

Corresponding Transport Region	Geologic Storage Basin	Geologic Formations	Storage Reservoirs in CO2_S_COM Geologic Database
Rocky Mountain	Powder River	Frontier; Lakota; Madison; Minnelusa; Muddy; Lower Sundance	Frontier 1 and 2, Lakota 1 and 2; Madison 1; Minnelusa 1 and 2 Muddy 4 and 7; Sundance 1 and 2

CO₂ cost-supply curves were generated for each basin to demonstrate each region’s cumulative prospective storage resource utilizing their available storage reservoirs. The cost-supply curve plots the cumulative prospective CO₂ storage resource available as FYBE storage cost increases, and therefore can be used to compare regional storage costs at specific cumulative storage thresholds. The CO₂ cost supply curves generated in this case study are used to report the minimum FYBE cost required in each basin to store CO₂ at the following cumulative storage thresholds: 5 billion tonnes Gt, 10 Gt, 15 Gt, 25 Gt, and 50 Gt.

The Storage Cost Case Study 1 results are shown in Section 3.2.1. The storage cost in each basin at the 5 Gt threshold, specifically, was used for the Guideline T&S Costs aggregated in Section 3.3.

2.2.2 Storage Cost Case Study 2: Project Design Variations – Methodology

The first storage cost case study evaluates storage project design variations and their impact on storage costs. Storage project design includes storage project geology parameters and storage project execution parameters. Three storage project design scenarios were assessed in this case study: 1) low-cost; 2) base; and 3) high-cost. The modifications in CO₂_S_COM input parameters across cases are illustrated in Exhibit 2-9.

Exhibit 2-9. Modeling parameters for low-cost, base, and high-cost scenarios

Parameter Modeled	Low-Cost Case	Base Case	High-Cost Case
Storage coefficient	P90	P50	P10
Structural setting	Regional dip		
Site selection and site characterization	2 yr (1 site)	3 yr (1 site)	3 yr (2 sites)
Permitting and construction (yr)	2	2	4
Injection operations (yr)	30		
PISC and site closure (yr)	25	50	50
3D seismic (2008\$/mi ²)	60,000	67,000	80,000

Deep monitoring wells ^A	1 dual-completed monitoring well per injection well with maximum of 15 wells	1 dual-completed monitoring well per injection well with maximum of 25 wells	1 dual-completed monitoring well per injection well with maximum of 50 wells
Density of wells needing corrective action (well/mi ²)	0.01	0.1	0.2

^AThese are calculated values, not model inputs. Dual-completed monitoring wells are completed in the reservoir and above the seal.

Cost parameters for each cost scenario modeled were modified from base case conditions to reflect a savings in cost or an additional cost burden due to potentially unique operational situations associated with changes to project design. The impact of these variations in geology and project execution variability are explored in more detail in Section 2.2.2.1 and Section 2.2.2.2, respectively.

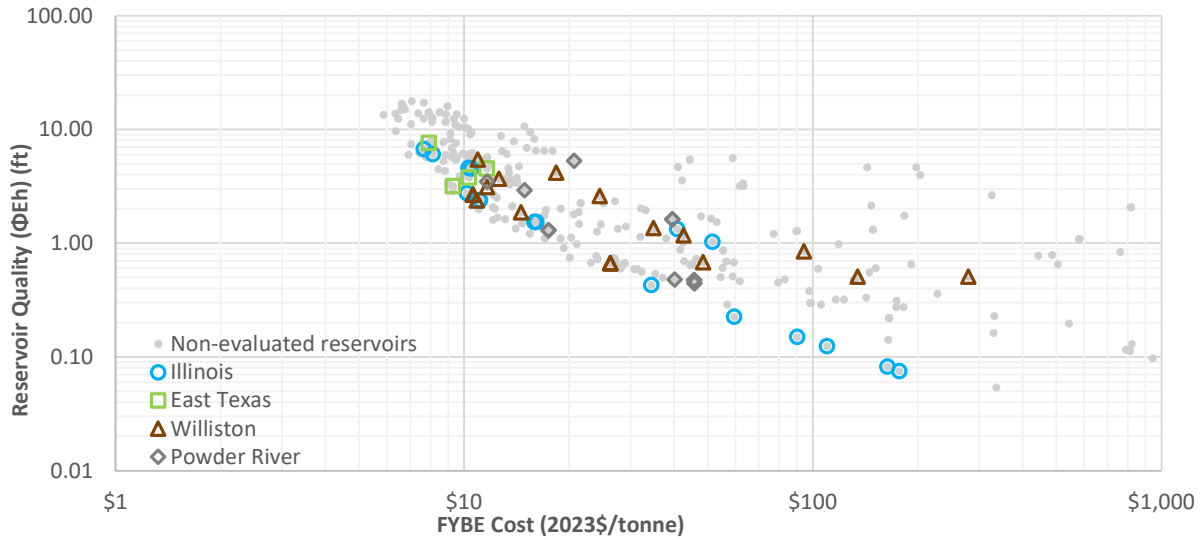
2.2.2.1 Storage Project Geologic Factors

Geologic factors that impact pore volume availability and accessibility are a primary cost driver for CO₂ storage. These geologic factors include the available area of the reservoir, the thickness, the porosity, and the storage coefficient. The storage coefficient depends on the lithology, depositional environment, and structural setting.

Additionally, reservoir thickness and permeability affect injectivity which, in turn, may influence the number of injection wells needed to safely inject the annual volume of CO₂ delivered to a storage site. Thick, permeable reservoirs enable higher injectivity [30] and higher injectivity results in fewer injection wells needed to achieve the targeted injection rate for a given project, and thus a lower relative per tonne cost to store CO₂. Furthermore, thick, porous reservoirs with high storage coefficients [31] will tend to generate a smaller areal extent for the CO₂ plume and have lower testing and monitoring costs relative to thinner formations with lower storage coefficients, resulting in a lower relative per tonne cost to store CO₂.

Exhibit 2-10 is a cross-plot (log-log scale) of reservoir quality (the product of reservoir porosity [Φ], storage coefficient [E], and height [h]) and FYBE cost to store a tonne of CO₂. Exhibit 2-10 includes data from each storage reservoir within the CO₂_S_COM, but specifically highlights storage reservoirs within the basins featured as part of this analysis. All data plotted in Exhibit 2-10 align with the base case. In general, storage reservoirs with higher reservoir quality typically have lower FYBE costs for storage. On the other hand, reservoirs with lower reservoir quality typically have higher FYBE costs for storage. A cross-plot of the product of permeability and reservoir thickness will also show a similar distribution.

Exhibit 2-10. Reservoir quality against FYBE cost for base case



Reservoir geologic have a significant influence on the resulting CO₂ plume and pressure front. The areal extent of the CO₂ plume, for instance, is another critical cost driver for a project. The monitoring and testing program that is part of a UIC Class VI permit is designed to monitor the extent of the CO₂ plume as it evolves over the lifetime of a project. Larger plumes increase the areal extent of the monitoring program, possibly increasing the number of monitoring wells needed, and the areal extent of seismic surveys designated to track the plume. The areal extent of a CO₂ plume can be calculated based on the storage reservoir’s geologic properties and the total CO₂ injected over the duration of a project as indicated in Equation 1 [31].

$$A_{CO_2} = G_{CO_2} / h\rho_{CO_2}\Phi E \quad \text{Equation 1}$$

Where:

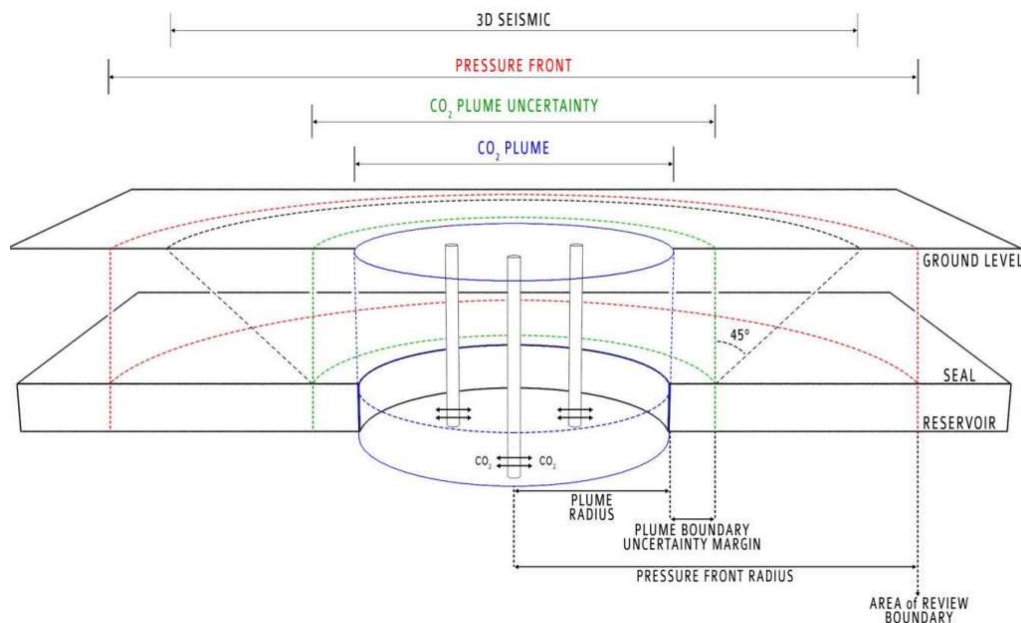
- A_{CO_2} = area of the CO₂ plume (ft²)
- G_{CO_2} = mass of total CO₂ stored (tonnes)
- h = thickness of the storage reservoir (ft)
- ρ_{CO_2} = density of the stored CO₂ at storage reservoir conditions^c (pounds per ft³)
- Φ = porosity of the storage reservoir rock (percent)
- E = storage coefficient for the storage reservoir rock (unitless)

The areal extent of the CO₂ plume is proportional to the mass of CO₂ injected over the life of a project and inversely proportional to storage reservoir quality. The approximated area of a

^c The units for CO₂ density (ρ_{CO_2}) in Equation 1 must be converted to tonnes per cubic foot to attain A_{CO_2} in square feet. The approximate conversion is 1 tonne = 2,204 pounds.

plume in the storage reservoir, as shown in Equation 1, is highly deterministic and does not account for geologic uncertainty. In the CO₂_S_COM, an uncertainty factor of 1.25 is applied to the results of Equation 1 to account for geologic uncertainty in the subsurface in estimating the CO₂ plume area size. Overall, Equation 1 shows how geologic factors like reservoir thickness, porosity, and storage coefficient as well as injected CO₂ volumes, can all directly impact the size of the resulting CO₂ plume.

Exhibit 2-11. Conceptual depiction of critical CO₂ storage cost driver boundaries and definitions part of CO₂_S_COM



Other key cost-influencing factors are also subject to the approximate size of the resulting CO₂ plume. Exhibit 2-11 summarizes these critical cost driver boundaries considered within CO₂_S_COM. For instance, the three dimensional (3D) seismic monitoring boundary is highlighted and is based off the size of the CO₂ plume uncertainty area, depth to top of the storage reservoir, and angle from CO₂ plume uncertainty edge to the ground surface (set at 45 degrees). As the CO₂ plume increases in size, so does the area in which 3D seismic monitoring is conducted to evaluate CO₂ plume evolution. The pressure front represents EPA's definition of the Area of Review (AoR). It is also an approximation, derived via the product of a multiplier (set at 10) and the CO₂ plume uncertainty area. While an important attribute to evaluate and monitor as part of an EPA UIC Class VI injection project and can limit the number of viable storage projects per formation, the pressure front is not a major cost factor within CO₂_S_COM.

For each storage reservoir modeled, the prospective CO₂ storage resource, as defined by Goodman et al. (2011) [31] and the Society of Petroleum Engineers (2017) [27], depends upon the available surface area, the porosity, reservoir thickness, CO₂ density at depth, and the storage coefficient. Storage reservoirs with larger storage capacities can typically attain unit cost savings (i.e., \$/tonne basis) via economies of scale by storing larger volumes of CO₂ than smaller reservoirs [4, 8]. The storage coefficient depends on the lithology, depositional environment,

and structural setting, and is listed in the CO2_S_COM geologic database [32]. Exhibit 2-12 lists the storage coefficient for the Mount Simon geologic formation for the regional dip structural setting that was evaluated in this guideline for low-cost, base, and high-cost cases. The lithology and depositional environment is provided for reference.

Exhibit 2-12. CO₂ storage coefficients for the Mount Simon geologic formation

Basin	Geologic Formation	Lithology	Depositional Environment	Storage Coefficient (P10) - Low-Cost Case	Storage Coefficient (P50) - Base Case	Storage Coefficient (P90) - High-Cost Case
Illinois	Mount Simon	Clastic	Strandplain	5.58%	5.63%	6.30%

The impact of the storage coefficient variability reported in Exhibit 2-12 on storage costs are demonstrated for the Mount Simon 3 storage reservoir in Exhibit 3-5 in Section 3.2.2.

2.2.2.2 Storage Project Execution Factors

The important activities impacting costs for these stages as modeled for this guideline’s low-cost, base, and high-cost scenarios in Exhibit 2-9 are:

- Site screening: One year
- Site selection and site characterization: One to two years
 - One or possibly two sites are subjected to an initial screening that involves 2 lines of a two-dimensional (2D) seismic survey covering the estimated CO₂ plume uncertainty area (shown conceptually in Exhibit 2-11).
 - This is followed up with the drilling of one stratigraphic well, sampling and testing from this stratigraphic well and a 3D seismic survey covering the CO₂ plume uncertainty area; property access and the right to inject into pore space are also leased.
 - This stage concludes with submittal to the regulatory authority of required plans (AoR and corrective action plan, testing and monitoring plan, injection well plugging plan, PISC and site closure plan, and ERR plan) for Class VI injection well permit. The AoR is an area where injection of CO₂ elevates pressures in the storage reservoir that may cause fluid to leak out of the storage reservoir and toward an USDW.
- Permitting and construction: Two to four years
 - This stage begins with the regulatory authority responding to submitted documents, the operator responding to any requests from the regulatory authority and the operator receiving conditional approval of the Class VI permit.

- The operator drills the injection wells and submits updated Class VI permit documents based on data collected during drilling to the regulatory authority. The regulatory authority then provides approval of the Class VI permit.
- Demonstration of financial responsibility.
- Installation of buildings, surface equipment, monitoring wells, and other monitoring equipment per submitted testing and monitoring plan.
- Except for drilling injection wells, most of the capital costs described above are incurred during the last year of construction.
- Operations: 30 years
 - Injection of an annual average mass of CO₂ each year for 30 years .
 - Assumes all monitoring wells are sampled at least once annually and a 3D seismic survey is performed once every 5 years; seismic surveys are based on the size of the CO₂ plume uncertainty area size.
 - AoR review and permit plans updates occur every five years.
 - Annual update of financial responsibility estimates/report.
 - Plugging injection wells at conclusion of injection operations.
 - Trust Fund is used to cover financial responsibility requirements for corrective action, injection well plugging, and PISC and site closure. Payments into the trust fund occur over a three-year period starting in the last year of permitting.
 - Emergency and remedial response is covered by an insurance policy with annual payments proportional to the mass of CO₂ injected in that year.
- PISC and site closure: 25 to 50 years
 - Monitoring continues per submitted post-injection and site care and site closure plan (i.e., monitoring wells continue to be sampled at least annually and 3D seismic surveys are conducted every 5 years per the plan).
 - Monitoring wells are plugged, and other monitoring equipment are removed, and the site is restored at the end of PISC.
 - While the trust fund is available to the regulatory authority, the regulatory authority can release money from the trust fund if they feel the fund is adequately funded. As such it was assumed that the costs during this period are covered by the storage site operator's Trust Fund.
- Long-term stewardship: This stage is not explicitly included in the model. The possible need to cover this cost is provided for by including in the model a state-sponsored Long-term Stewardship Trust Fund that the storage operator pays into during operations.

2.2.3 Storage Cost Case Study 3: CO₂ Mass Flow Rate Variations – Methodology

To demonstrate how CO₂ mass flow rate impacts CO₂ storage costs, CO₂_S_COM was used to estimate storage costs for different saline storage projects sized to store from an average of 1.42 Mt/yr to an average of 5.14 Mt/yr, and range in capacity factors from 80% to 85%, as shown in Exhibit 2-13.

The CO₂ storage project in each mass flow rate scenario was assumed to be located in the Illinois Basin’s Mount Simon 3 storage reservoir, using financial parameters outlined in Exhibit 2-6 and the base project design scenario parameters outlined in Exhibit 2-9. The injection well count listed in Exhibit 2-13 is determined in CO₂_S_COM by dividing the maximum annual CO₂ mass flow rate by the injection rate capacity per well, assumed in this guideline to be 1.336 Mt/yr per well.

Exhibit 2-13. CO₂ mass flow rates and injection well count assessed in Storage Cost Case Study 3 scenarios

Average Annual CO ₂ Injection Rate	Maximum Annual CO ₂ Injection Rate	Capacity Factor	CO ₂ Storage Project Injection Well Count
Mt/yr	Mt/yr	%	Count
5.14	6.05	85	5
4.89	5.75	85	5
4.85	5.71	85	5
4.62	5.44	85	5
4.53	5.33	85	4
4.31	5.07	85	4
3.20	4.00	80	3
3.17	3.96	80	3
3.11	3.89	80	3
1.84	2.16	85	2
1.80	2.12	85	2
1.71	2.01	85	2
1.53	1.80	85	2
1.50	1.76	85	2
1.42	1.67	85	2

2.3 GUIDELINE T&S COSTS METHODOLOGY

The final case study in this guideline demonstrates combining regional transport and storage costs to create comparable T&S costs by region. This case study combined regional transport costs from the four U.S. regions, described in Section 2.1.1. with storage costs from corresponding basins as described Section 2.2.1. The transport cost in each region assumed fixed pipeline distance (100 km, 62 mi) scenarios. The storage costs in each region assumed the FYBE cost of a storage project in a basin storing a cumulative 5 Gt of CO₂ over 30 years. Both transport and storage cost scenarios assumed the same average CO₂ mass flow rate (4.31 Mt/yr) and

capacity factor (85%). The resulting combined T&S costs are termed “Guideline T&S Costs”, and represent comparable T&S costs that can be used in energy systems studies. The Guideline T&S Costs are effectively the T&S expense paid by the CO₂ capture project owner to transport and store each tonne of CO₂ captured during the assumed 30-year operational period.

3 MODELING RESULTS

This section provides an overview of the modeling results from the various case studies used to generate T&S costs under different modeling scenarios. These case study results and sensitivity trends were generated to be able to be easily referenced by a variety of energy systems studies that would incorporate T&S costs. Results are from modeling runs performed with the CO₂_T_COM and the CO₂_S_COM using parameters described above as well as default values within the models.

3.1 CO₂ TRANSPORT COST RESULTS OVERVIEW

This section provides the transport cost results of the CO₂ pipeline transport cost modeling, broken out by the two CO₂ transport cost case studies described in Sections 2.1.1 and 2.1.2. These case studies demonstrated the impact of regional variations in material and labor costs, and variations in CO₂ mass flow rate and pipeline length, respectively, on the cost of transport.

3.1.1 Transport Cost Case Study 1: Regional Variation – Results

The case study described in Section 2.1.1 was designed to estimate the FYBE transportation cost for a 100 km (62 mi) pipeline between a capture project capturing an annual average of 4.31 Mt/yr of CO₂ and a storage project site in each of four transportation regions. Modeling results in each region estimated that the lowest cost configuration for pipelines will have a 12-in pipe diameter and one booster pump. Transport costs for this configuration are reported in Exhibit 3-1.

Despite all pipelines having the same length and diameter in their design, FYBE transportation costs vary between regions. This variation is due to the Brown et al., regression equations’ pipeline construction material and labor cost factors which vary by region (Exhibit 2-5).

Exhibit 3-1. Comparable CO₂ transport costs by region

Transport Region	Transport Cost (2023\$/tonne)
Great Lakes	2.35
Southwest	2.42
Great Plains	1.58
Rocky Mountain	1.58

3.1.2 Transport Cost Case Study 2: CO₂ Mass Flow Rate and Distance Variations – Results

The case study described in Section 2.1.2 was designed to estimate FYBE transportation cost as a function of CO₂ mass flow rate, pipeline distance, and the CO₂ source’s capacity factor (which defines the average to maximum CO₂ mass flow rate ratio). Transportation costs for this configuration are shown in Exhibit 3-2.

Exhibit 3-2. FYBE cost sensitivity to pipeline length, pipeline capacity factor, and mass of CO₂ transported

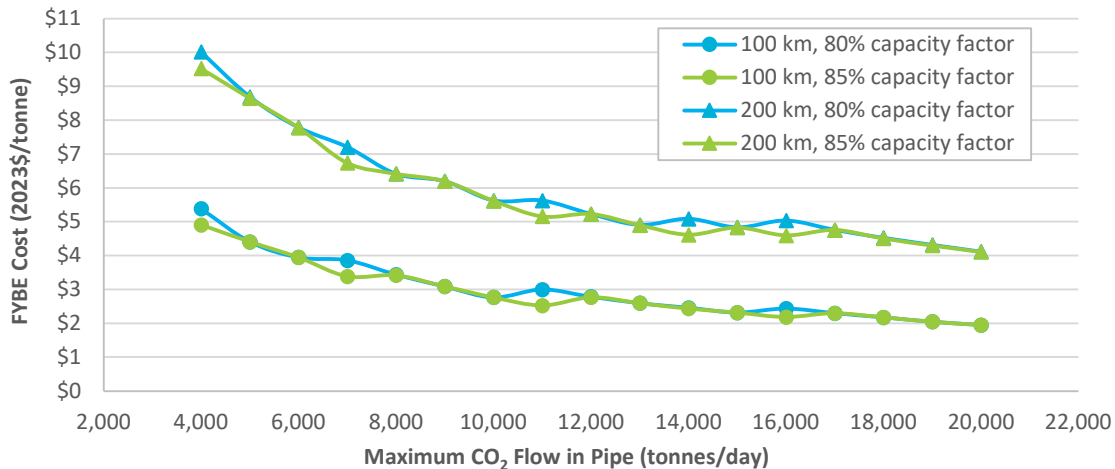


Exhibit 3-2 indicates higher CO₂ mass flow rates have lower FYBE transport costs on a per tonne of CO₂ basis. This is largely due to economies of scale benefits related to pipeline diameter (i.e., a small increase in pipeline diameter and pipeline material can result in a large increase in CO₂ capacity). Additionally, higher capacity factor assumptions tend to offer a cost savings as shown by the relationship between the green and blue lines in Exhibit 3-2. As the mass flow rate increases, the diameter of the pipe or the number of pumps may change. There are some small discontinuities when the pipeline configuration changes (such as at 11,000 tonne/day for the 100-km pipeline when the number of pumps increases from zero to one and at 14,000 tonne/day for the 200-km pipeline when the number of pumps increases from two to three) which demonstrate where lower capacity factors cause a slight increase in FYBE costs. Exhibit 3-2 also demonstrates that the longer the pipeline, the higher the FYBE cost, with the cost being roughly proportional to the length at the two lengths investigated.

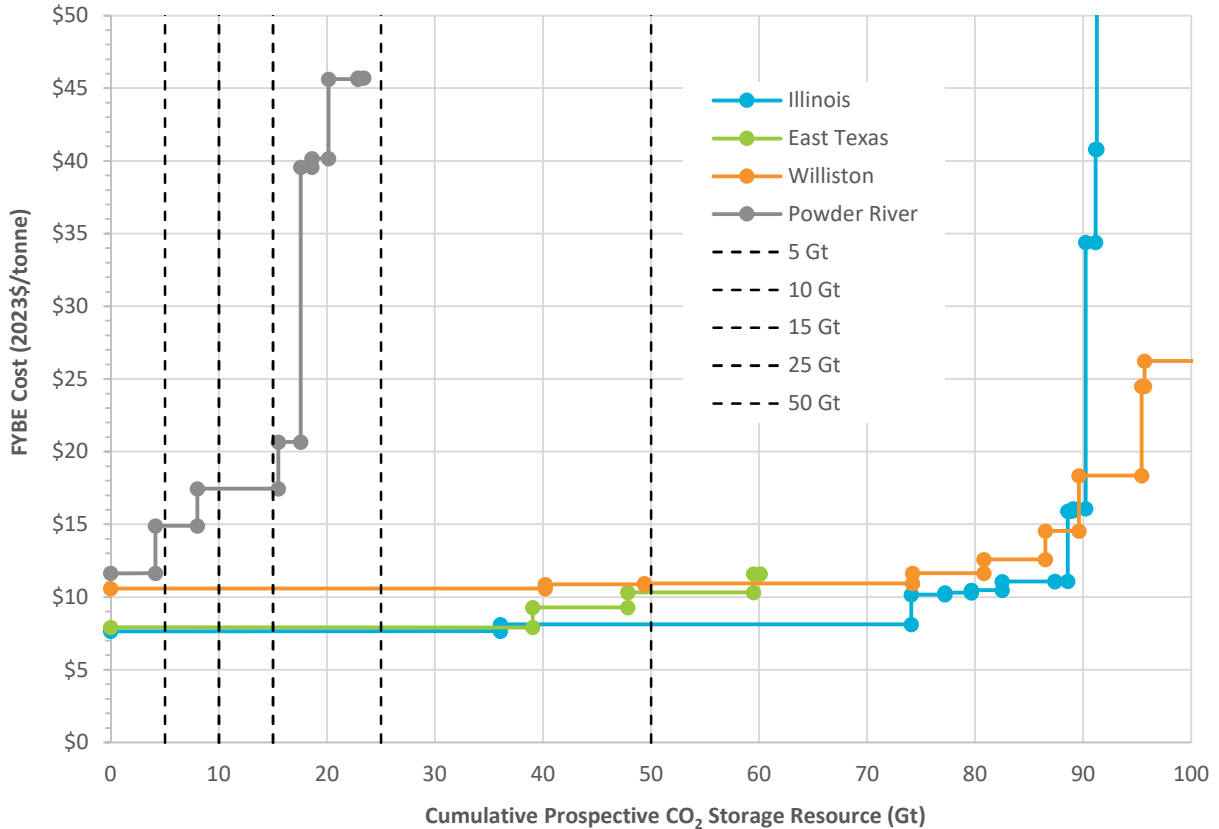
3.2 CO₂ STORAGE COSTS RESULTS OVERVIEW

This section provides the storage cost results of the CO₂ saline storage cost modeling, broken out by the three CO₂ storage cost case studies described in Sections 2.2.1, 2.2.2, and 2.2.3. These case studies demonstrated the impact of regional variations in drilling costs and geology, variations in project design, and variations in CO₂ mass flow rate, respectively, on the cost of storage.

3.2.1 Storage Cost Case Study 1: Regional Variation – Results

As described in Section 2.2.1, the cost of storing a tonne of CO₂ in a basin at a given cumulative CO₂ mass threshold varies depending on the basin’s reservoir-specific geologic attributions and regional changes in the cost of drilling. Exhibit 3-3 quantifies the regional variation in storage costs with a supply curve that presents the prospective cumulative resource potential for CO₂ that can be theoretically stored in reservoirs within each of the four select basin along with their associated FYBE cost to store CO₂, for the base case conditions outlined in Exhibit 2-9. Exhibit 3-3 graphs cumulative prospective CO₂ storage resource thresholds (5 Gt, 10 Gt, 15 Gt, 25 Gt, and 50 Gt CO₂) to demonstrate the minimum FYBE saline storage FYBE costs at each threshold.

Exhibit 3-3. Cumulative prospective CO₂ storage resource cost supply curves for base case



The East Texas, Illinois, and Williston basins have a similar flat cost supply trend from 0-60 Gt., with the Williston Basin having slightly higher costs from 0-50 Gt, and the East Texas Basin’s cost increasing to be closer to the Williston Basin’s costs after 35 Gt. These three basins have abundant, large, high-quality storage reservoirs. The Powder River Basin’s cost supply curve is relatively steep by comparison, indicative of the basin having fewer, smaller high-quality

storage reservoirs. The geologic reservoir quality-determining properties like thickness, porosity, and area that influence these cost trends are discussed in detail in Section 2.2.2.1.

The minimum FYBE cost data extracted from the curves in Exhibit 3-3 at the cumulative CO₂ storage thresholds are shown in tabular form in Exhibit 3-4.

Exhibit 3-4. Minimum FYBE CO₂ storage cost in four basins at different cumulative prospective CO₂ storage resource thresholds for base case

Basin	Cumulative CO ₂ Injected and Stored				
	5 Gt	10 Gt	15 Gt	25 Gt	50 Gt
	Minimum FYBE CO ₂ Cost [2023\$/tonne]				
Illinois	7.65				8.12
East Texas	7.92				10.31
Williston	10.59				10.94
Powder River	14.90	17.45		45.72 ^A	

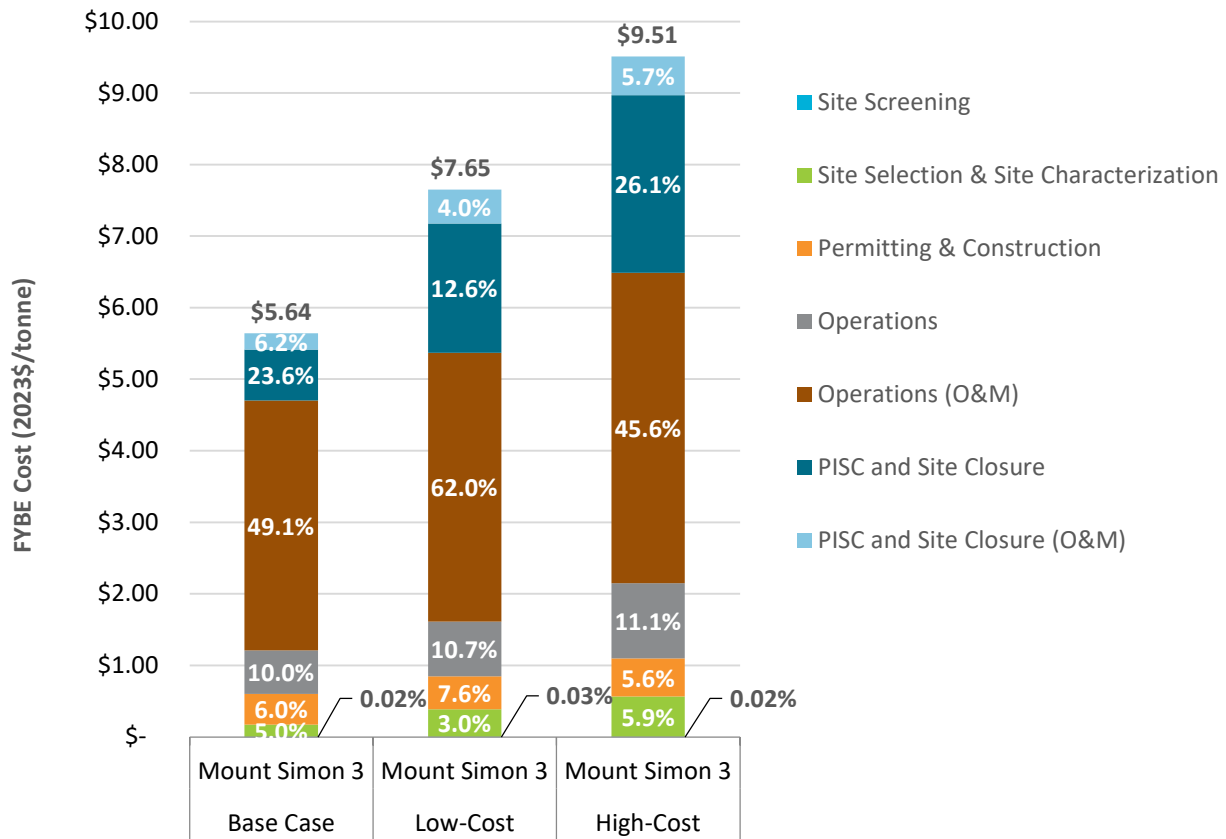
^APowder River Basin’s maximum cumulative prospective storage resource is less than 25 Gt in the base case modeling scenario. Reported costs of \$45.72/tonne (2023\$) reflect the cost to store the maximum cumulative potential CO₂ mass in the basin 23.4 Gt.

Guideline T&S Costs in Section 3.3 use the minimum FYBE cost of CO₂ storage at the 5 Gt threshold for the base case reported in Exhibit 3-4.

3.2.2 Storage Cost Case Study 2: Project Design Variations – Results

The FYBE storage cost in a single storage reservoir can vary with assumptions about geologic parameters, and assumptions about the execution of the storage project. Exhibit 3-5 illustrates the difference in FYBE cost of CO₂, broken out by project phases (reported as a percent contribution), for a CO₂ storage project in the Illinois Basin’s Mount Simon 3 storage reservoir for the low-cost, base, and high-cost scenarios outlined in Exhibit 2-9. Project phases imply capital costs unless marked “O&M”, in which case these costs are operations and maintenance expenditures. Storage project geology assumptions between the low-cost, base, and high-cost scenarios are discussed in more detail in Section 2.2.2.1, and are associated with storage coefficient. Storage project execution assumptions between the three scenarios are discussed in more detail in 2.2.2.2, and are associated with duration of pre-operational project phases (i.e., site selection and site characterization; permitting and construction), the duration of the post-operational project phase (i.e., PISC), 3D seismic costs, the maximum count for deep monitoring wells, and the density of wells needing corrective action.

Exhibit 3-5. CO₂ storage project FYBE cost, broken out by project phase, in the Mount Simon 3 for low-cost, base, and high-cost scenarios



Overall storage costs increase from the low-cost case to the high-cost case due to changes in the following parameters listed in Exhibit 2-9:

- Storage coefficient decreases, reducing the storage volume per unit area and increasing the plume size and associated monitoring costs (primarily 3D seismic costs).
- Number of years to complete site selection and site characterization and permitting and construction increases, delaying operations and positive cash flow from injection revenue.
- PISC and site closure period of 25 years in the low-cost case increases to the default period of 50 years for the base and high-cost cases, increasing monitoring and financial responsibility costs.
- 3D seismic costs increase from \$60,000/mi² to \$80,000/mi² (in 2008\$).
- Number of monitoring wells drilled increases.
- Increasing number of wells requiring corrective action increases the cost to perform corrective action and increases the cost of the financial instrument to cover this cost for financial responsibility.

3.2.3 Storage Cost Case Study 3: CO₂ Mass Flow Rate Variations – Results

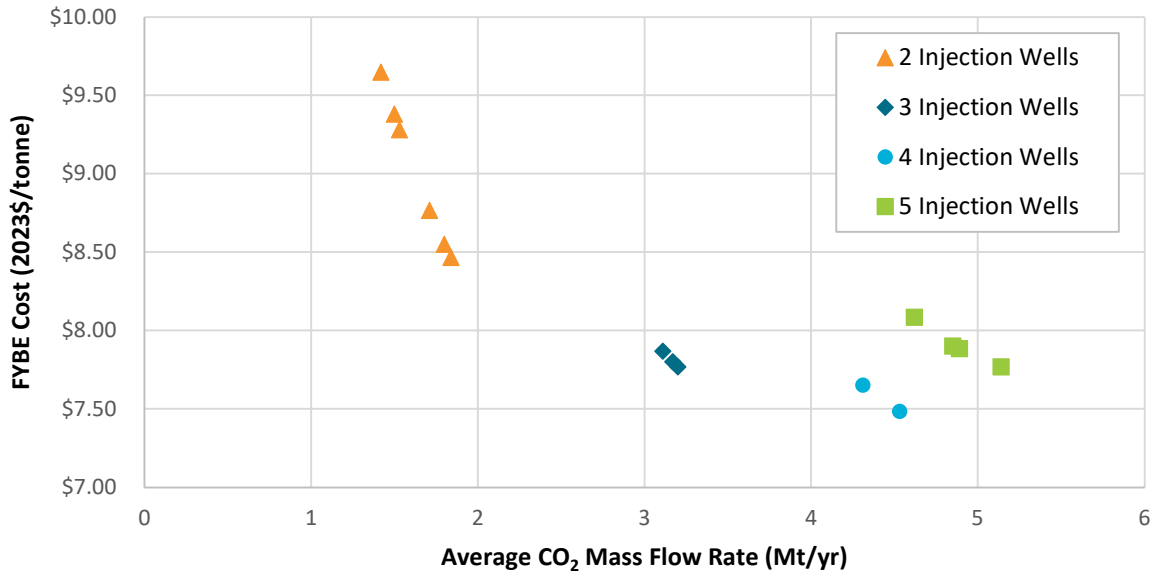
Exhibit 3-6 reports the FYBE cost of storage for project scenarios of varying average annual CO₂ mass flow rate (Mt/yr) and maximum CO₂ mass flow rate (converted to a Mt/yr equivalent). As described in Section 2.2.3, all the results in this case study are from CO₂_S_COM runs for storage projects in the Illinois Basin’s Mount Simon 3 storage reservoir, which assumed the base project design scenario outlined in Exhibit 2-9.

Exhibit 3-6. Mount Simon 3 storage reservoir FYBE costs for different CO₂ mass flow rates

Average Annual CO ₂ Injection Rate	Maximum Annual CO ₂ Injection Rate	Capacity Factor	CO ₂ Storage Project Injection Well Count	CO ₂ Storage Cost
Mt/yr	Mt/yr	%	Count	2023\$/tonne
5.14	6.05	85	5	\$7.77
4.89	5.75	85	5	\$7.88
4.85	5.71	85	5	\$7.90
4.62	5.44	85	5	\$8.08
4.53	5.33	85	4	\$7.48
4.31	5.07	85	4	\$7.65
3.20	4.00	80	3	\$7.77
3.17	3.96	80	3	\$7.80
3.11	3.89	80	3	\$7.87
1.84	2.16	85	2	\$8.47
1.80	2.12	85	2	\$8.55
1.71	2.01	85	2	\$8.77
1.53	1.80	85	2	\$9.28
1.50	1.76	85	2	\$9.38
1.42	1.67	85	2	\$9.65

The per tonne of CO₂ FYBE storage cost in a storage reservoir tends to decrease as the CO₂ mass flow rate (i.e., planned injection rate) increases, primarily due to economies of scale. Exhibit 3-7 shows graphically the relationship between FYBE storage cost and the average CO₂ mass flow rate from Exhibit 3-6, and highlights the impact of adding additional injection wells to a CO₂ storage project.

Exhibit 3-7. Average annual CO₂ injection rate impact on FYBE cost of CO₂ storage in the Mount Simon 3



Note that the linear relationship between the CO₂ mass flow rate and the FYBE cost in Exhibit 3-7 changes when the required number of injection wells change; this is due to the increase in capital and operating costs associated with the additional well(s). For example, the jump in FYBE cost of \$7.48/tonne at an average annual mass flow rate of 4.53 Mt/yr (equivalent to a maximum injection rate of 5.33 Mt/yr) to \$8.08/tonne at 4.62 Mt/yr (equivalent to a maximum injection rate of 5.44 Mt/yr) is due mostly to the extra capital and operating expenses associated with adding a fifth injection well. The injection well count requirement is determined in CO₂_S_COM by dividing the maximum annual CO₂ mass flow rate by the injection rate capacity per well, (assumed in this guideline to be 1.336 Mt/yr per well).

3.3 GUIDELINE T&S COSTS RESULTS

Exhibit 3-8 reports the “Guideline T&S Costs” in the Midwest, Texas, North Dakota, and Montana study regions. The Guideline T&S Costs, as described in Section 2.3, are an aggregate of the regional transport cost results from the Regional Variation Transport Case Study, and the regional storage cost results at the 5 Gt storage threshold from the Regional Variation Storage Case Study. The study regions align with each of the transport regions described in Section 2.1.1 and each of the storage basins in Section 2.2.1, as shown in Exhibit 3-8.

Exhibit 3-8. Guideline T&S Costs by study region

Guideline Region	Transportation Region	Storage Basin	Transport Cost (2023\$/tonne)	Storage Cost (2023\$/tonne)	Total T&S Cost (2023\$/tonne)
Midwest	Great Lakes	Illinois	2.35	7.65	10.00
Texas	Southwest	East Texas	2.42	7.92	10.34
North Dakota	Great Plains	Williston	1.58	10.59	12.17

Guideline Region	Transportation Region	Storage Basin	Transport Cost (2023\$/tonne)	Storage Cost (2023\$/tonne)	Total T&S Cost (2023\$/tonne)
Montana	Rocky Mountains	Powder River	1.58	14.90	16.48

The Guideline T&S Costs demonstrate that when transport distances are kept relatively low (in this case, 100 km (62 mi)), indicative of local siting of storage relative to the capture location, transport represents a minor constituent of the overall T&S costs; consequently, storage represents a larger portion of overall T&S costs.

The range of Guideline T&S Costs can be used as a basis for energy systems studies incorporating T&S costs, provided transport and/or storage project specifics are not known, or unaccounted for. However, as the Guideline T&S Costs demonstrate, geographic location impacts cost drivers like material costs, labor costs, drilling costs, and availability of quality storage reservoir geology. If possible, it is recommended project(s) locations be accounted for when performing energy systems studies. The variability in transport and storage costs presented in the two transportation case studies (Section 3.1) and the three storage case studies (Section 3.2), further demonstrate the importance of accounting for CCS project design specifics (e.g., CO₂ mass flow rate, pipeline distance, and geographic location) in energy systems studies when feasible.

4 REVISION CONTROL

Exhibit 4-1. Revision table

Revision Number	Revision Date	Description of Change
1	September 30, 2013	Updated cost estimates.
2	February 12, 2014	Document edited and formatted.
3	November 30, 2016	Updated cost estimates. Document edited.
4	July 31, 2017	Updated cost estimates. Document edited.
5	November 6, 2017	Updated cost estimates for high-cost with water treatment case. Document edited.
6	February 11, 2019	Updated financial parameters and electricity price. New methodology for high-cost cases with water management and treatment Document edited.
7	August 19, 2019	Updated financial parameters. New methodology for obtaining real costs.

Revision Number	Revision Date	Description of Change
		Document edited.
8	March 15, 2024	Updated financial parameters to put results in real 2023\$. Updated transport capital cost equations. Removed anticline and dome structural setting analyses. Removed high-cost cases with water management and treatment. Added storage results accounting for pressure interference. Document edited.
9	July 11, 2024	Report reorganized to separate transport, storage, and combined T&S case study modeling and results. Storage cost sensitivity case studies added to demonstrate impact of variability in regional variations, project design, and CO ₂ mass flow rates on costs. “Guideline T&S Costs” for comparable combined T&S costs reported at the 5 Gt threshold as a separate case study. Document edited.

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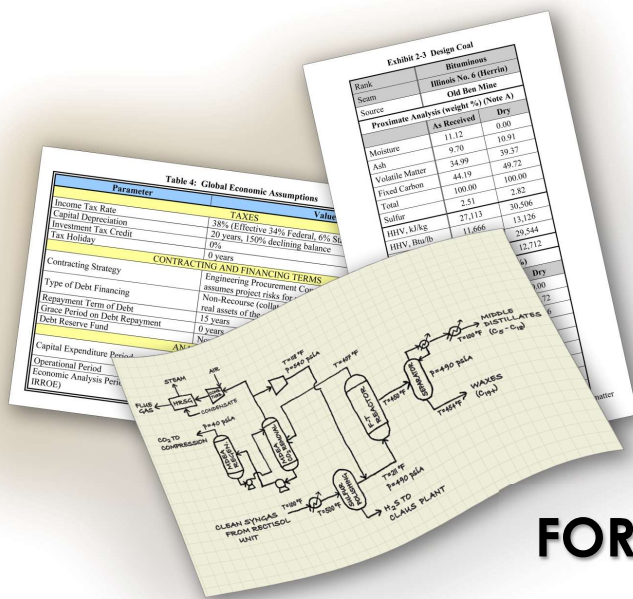
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