CONFERENCE PROCEEDINGS

Models of CO_2 Transport and Storage Costs and Their Importance in CCS Cost Estimates

Sean T. McCoy, Carnegie Mellon University

Edward S. Rubin, Carnegie Mellon University

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Abstract

In recent years, global concerns about greenhouse gas emissions have stimulated considerable interest in CO_2 capture and storage (CCS) as a potential “bridging technology” that can achieve significant CO_2 emission reductions while allowing fossil fuels to be used until alternative energy sources are more widely deployed. To date, the literature in this field has focused most heavily on CO_2 capture technologies, which are believed to be the most costly components of a CCS system. Far fewer studies have addressed the costs of CO_2 transport and storage in comparable detail. Most commonly, transport and storage costs are either omitted from cost analyses, or reported simply as a cost per ton CO_2 with little or no detail as to the basis for such estimates. Our review of the CCS literature reveals frequent inconsistencies and lack of clarity in defining the scope of the CO_2 capture, transport and storage components, with the result that some CCS cost elements—especially the significant costs of CO_2 compression—often are double-counted as parts of both the CO_2 capture cost and the CO_2 transport/storage cost.

This paper seeks to elucidate the key factors governing CO_2 transport and storage costs through the development of engineering and economic models of CO_2 transport via pipelines, and geological storage of CO_2 in deep saline aquifers. The models described in this paper are intended to provide first-order cost estimates that are sensitive to key site-specific or project-specific parameters, both technical and financial. They are being developed in conjunction with the IECM-cs power plant model—a DOE-sponsored project to provide a publicly available tool for estimating the performance, emissions and costs of alternative CCS systems. In this paper, the new transport and aquifer storage models are applied to a case study of CO_2 storage from a 500 MW coal fired plant in the Wabamun Lake area of Alberta, Canada. Results for this case indicate significant uncertainties in the cost of CO_2 transport and storage, primarily due to the variability of reservoir geological parameters, as well as other factors such as transport distance and power plant capacity factor. As a consequence, the combined cost of transport and storage (on a cost per tonne CO_2 basis) could represent more than 32 % of the total CCS cost, as compared to a nominal estimate of less than 15% of the total. This case study illustrates the importance of considering key site-specific factors and their variability or uncertainty in preliminary cost estimates.

Introduction

Large reductions in carbon dioxide emissions from energy production will be required in the near future to stabilize atmospheric concentrations of CO_2 [1,2]. One option to reduce carbon intensity while allowing for continued use (in the short-term) of fossil fuels is carbon capture and storage (CCS); i.e., the capture of CO_2 directly from anthropogenic sources and disposal of it in geological sinks for significant periods of time [3]. CCS requires CO_2 to be captured from energy production processes, compressed to high pressures, transported to a storage site, and injected into a suitable geologic formation. Each of these steps is capital and energy intensive, and will have a significant impact on the cost of energy production. Government regulators, policy-makers (public and private), and other interested parties require methods to estimate the cost of geological carbon storage. While many studies of carbon capture processes have been undertaken [4-6] and reasonable engineering-economic models have been developed [7], there is a paucity of engineering-economic models for transport and storage. Moreover, this lack of engineering-economic models has lead to inconsistencies in the definition of the scope of the transport and storage processes. For example, the energy intensive process of CO_2 compression can be accounted for as either part of the capture process, as in this paper, or as part of the transport process [8]. Any costs that are quoted for transport and storage must clearly identify what they include.

This paper details the development of models to determine the cost of CO_2 transport from the site of capture to the location of storage via pipeline, and the cost of subsequent storage in a deep saline aquifer*. Both models will be discussed in the context of the electric power industry, which generates nearly 39% of all CO_2 emissions in the United States from large point sources [9]. In this context, the cost per tonne of transporting and storing CO_2 from a range of capacities of power plants will be determined and, the effect of varying pipeline design parameters and geological parameters will be quantified. Furthermore, in an attempt to quantify sensitivity of the models to uncertainty and variability in design parameters, a probabilistic analysis of a specific scenario will be performed, which shows the range of costs that could occur and the probability associated with these costs.

Modeling Transport of CO_2 via Pipeline

The transport model developed in this research takes engineering and design parameters, such as pipeline length and design CO_2 mass flow, as well as economic parameters, such as the fixed charge factor, and operating and maintenance charges as input. From these inputs the required pipe diameter and cost per tonne of CO_2 transported are calculated. The transport model is based on previous work by the Massachusetts Institute of Technology (MIT) for the United States Department of Energy (DOE) [10] and has been extended to include a comprehensive physical properties model for CO_2, booster pumping station options, segment elevation changes, and probabilistic assessment capabilities. The boundaries, and primary inputs and outputs of the transport model are summarized in Figure 1.

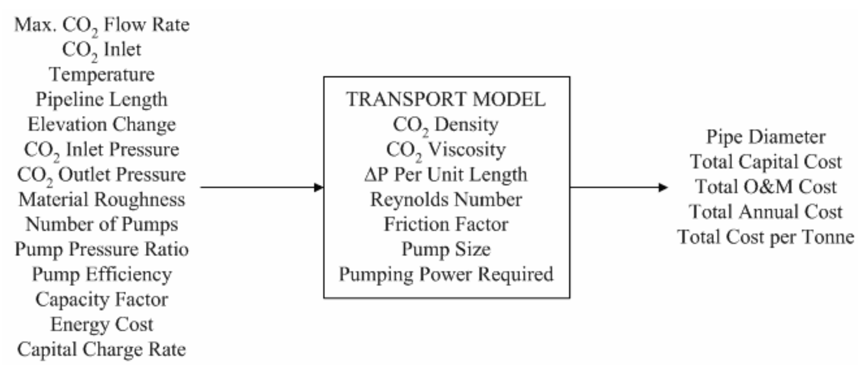


Figure 1. The boundaries, inputs, and output of the pipeline model.

The pipeline is modeled as a series of pipe segments located between booster pumping stations. Based on the input information to the transport model, the required pipeline diameter for each segment is calculated. The pipeline segment diameter is calculated from a mechanical energy balance on the flowing CO_2, which can be found in [11]. The energy balance is simplified by approximating supercritical CO_2 as an incompressible fluid and the pipeline flow and pumping processes as isothermal.

Booster pumping stations may be required for longer pipeline distances or for pipelines in mountainous or hilly regions. Additionally, the use of booster pumping stations may allow a smaller pipe diameter to be used, reducing the cost of CO_2 transport. The pumping station size is also developed from an energy balance on the flowing CO_2 [11] in a manner similar to the calculation of the pipe segment diameter. Both the pumping station size and pipeline diameter are calculated on the basis of the design mass flow rate of CO_2, while the pumping station annual power consumption is calculated on the basis of the nominal mass

* A formation lying at least 800m below the ground surface whose fluid saturation, porosity and permeability allows the production of saline water. Water produced from formations at these depths is unfit for industrial or agricultural use, or human consumption.

flow rate of CO_2[†]. The pumping station size is required to determine the capital cost of the pump, while the pumping station annual power requirement is required to calculate the variable operating and maintenance cost.

The capital cost of the CO_2 pipeline is based on capital cost data for natural gas pipelines contained in the United States' Federal Energy Regulatory Commission (FERC) filings and published in the Oil and Gas Journal [10]. Given the similarities between natural gas and CO_2 pipelines, we believe that it is reasonable to use the capital cost of natural gas pipelines to approximate capital costs of CO_2 pipelines in the absence of empirical data. Operating costs are based on costs for currently operating CO_2 pipelines in the Permian Basin [10]. The capital cost of a CO_2 pumping station has been estimated by the IEA for a study involving the pipeline transmission of CO_2 [12].

Modeling Storage of CO_2

The model takes engineering and design parameters, such as formation depth, formation permeability, CO_2 mass flow, and economic parameters, such as project lifetime, discount rate, and monitoring and verification costs as input. From these inputs the number of wells required and the cost per metric ton of CO_2 injected are calculated. The transport model is based on previous work [10] and has been extended to include a comprehensive physical properties model for CO_2, and probabilistic assessment capabilities. The boundaries, and primary inputs and outputs of the transport model are summarized in Figure 2.

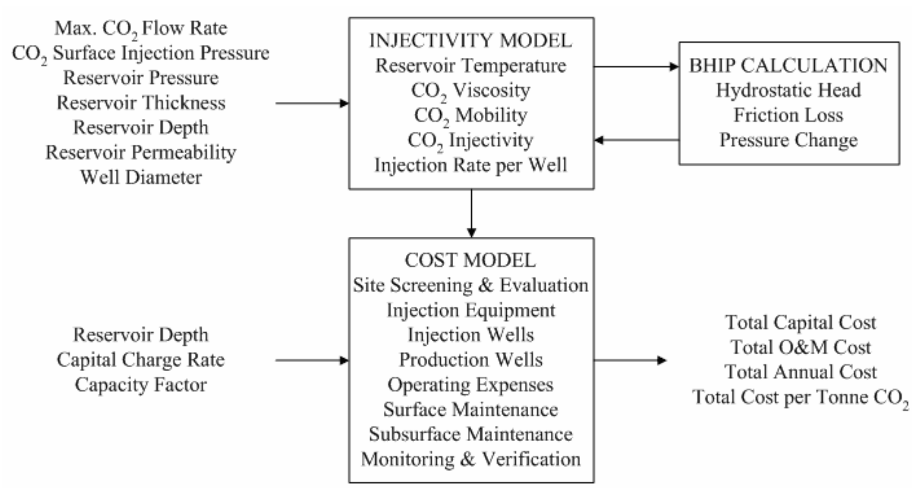


Figure 2. The boundaries, inputs, and output of the aquifer storage model.

The model treats the cost of CO_2 injection into the aquifer solely as a function of the number of injection wells and the well depth. Design and engineering of surface equipment (i.e., distribution piping between the terminus of the CO_2 trunk line and the well heads, CO_2 flow control equipment, and equipment to monitor the well condition) is not explicit in the model, however; capital and operating costs of this equipment are included by scaling a base cost to the number of injection wells required.

The problem of finding the appropriate number of wells for a given geology and injection rate of CO_2 is formulated as a root finding problem; that is, the correct number of wells is found when the difference between the required per well injection rate for a given number of wells and the calculated per well injection rate for the same number of wells is zero. This formulation of the problem is shown as Equation

[†] The nominal mass flow rate of CO_2 is the product of the power plant capacity factor and the design mass flow rate of CO_2

1, where $E(N_w)$ is error between the required and calculated flow rate as a function of the number of injection wells, N_w.

$$E(N_w) = \dot{m}_{W,\,req'd}(N_w) - \dot{m}_{W,\,calc}(N_w) \tag{1}$$

Equation 1 is expanded by substituting the correlation of Law and Bachu [13] for the calculated injection rate, which results in Equation 2.

$$E(N_w) = \frac{\dot{m}}{N_w} - 0.000538\frac{\rho(k_h k_v)^{0.5} h(p_i - p_a)}{\mu \ln\left(\frac{r_e}{r_w}\right)} \tag{2}$$

In Equation 2, $\dot{m}_w$ represents the injection rate; $\dot{m}$ is the total mass injection rate for the project; ρ is the density of CO_2 at formation conditions; h represents the aquifer thickness; p_i is the bottom hole injection pressure; p_a is the far field aquifer pressure; k_h and k_v are the horizontal and vertical permeability of the formation to CO_2; μ is the viscosity of CO_2 under formation conditions; and, r_w and r_e are the radii of the well and injection influence, respectively. The BHIP in Equation 2 is calculated assuming that there is no heat transfer between the flowing surrounding formations to the CO_2 (i.e. adiabatic flow). Further details of the BHIP calculation method can be found in [11].

Several important assumptions apply to Equation 2: the aquifer is homogeneous and anisotropic[‡]; the injection well is vertical and completed through the full thickness of the aquifer; the properties of CO_2 are constant in the aquifer; and, the radius of influence is constant for the 3 inch diameter well modeled. As a rule of thumb, the logarithm of natural logarithm of the ratio of the radii of injection influence to the well diameter is equal to 7.5 [4].

Well drilling costs are calculated based on a correlation developed in the DOE study [10] from data contained in the 1998 Joint Association Survey (JAS) on Drilling Costs report [14]. Regression analysis on drilling cost data for onshore oil and gas wells provided the relationship [11]. Correlations used to determine the capital and operating and maintenance (O&M) costs of the injection equipment are based on the Energy Information Administration cost indices for petroleum production [15], which are expected to be similar to the costs for CO_2 storage. The O&M cost correlations were developed in a study performed for the DOE [10]. Average equipment costs and O&M costs were determined on a per well basis and, in the case of injection equipment and subsurface maintenance, are scaled to reflect typical economies of scale [11].

Transport and Storage Case Study

To illustrate the application and utility of the model developed in this research, a case study has been conducted based on a scenario in which CO_2 is captured from coal fired power plant located in the Wabamun Lake area of the province of Alberta, Canada. This region, shown in Figure 3, is host to over 4000 MW of coal fired generation, including Canada's first supercritical pulverized coal (PC) unit [16,17]. The model is used to evaluate the potential cost of injection into a specific candidate formation from the standpoint of the perspective operator or owner of a power plant; i.e., the perspective owner or

[‡] If the actual aquifer is not-homogeneous, and the well is located in a region of the aquifer with higher permeability than average, the injectivity could be much higher than suggested by a calculation using a total average for the aquifer. The opposite also applies: if the well is located in a region of locally lower permeability, the injectivity could be much lower than predicted.

operator would have control over design aspects of the capture, transport, and storage system, but may not know with certainty the emissions rate of the power plant they will be constructing. To identify the sensitivity of the outputs to uncertainty and variability in the inputs, a Monte Carlo analysis has been performed on the models.

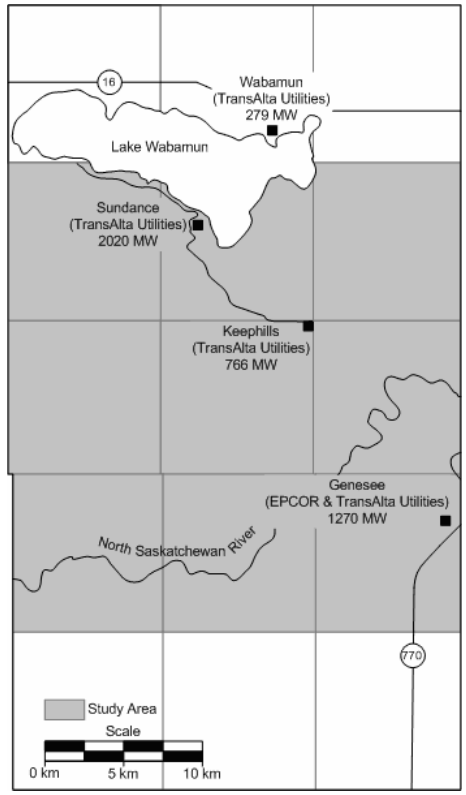


Figure 3. The area surrounding Lake Wabamun in Central Alberta, used as the setting for the case study [18].

Case Study Parameters

The parameters for the case study are summarized in Table 1. The distribution for annual CO_2 mass flow rate is based on PC plant sizes between 320 MW and 530 MW, or Integrated Gasification Combined Cycle (IGCC) plant sizes between 380 MW and 630 MW[§] and the distribution for capacity factor is based on data from US Environmental Protection Agency's software package, eGRID2002PC [19]. The fixed charge factor distribution is believed to be representative of typical electricity industry rates.

Transport parameters are based on a relatively short pipeline between the CO_2 source and the sink, as the entire Wabamun Lake area sits atop a suitable deep saline aquifer [20,21]. The short pipeline distance means that booster pumping stations would likely not be required, thus they have been excluded from the analysis. The upper and lower bounds of the distribution for annual O&M cost of the pipeline is arbitrary, but covers a reasonable range of operating costs [19].

The target formation for storage is a cretaceous glauconitic sandstone aquifer in the Upper Mannville Group [13,20]. This formation is located at depths greater than 1460 m, and overlain by several regional

[§] These capacities and annual emissions correspond to emission rates of approximately 1067 kg/MWh for a PC plant and 902 kg/MWh for a IGCC plant.

scale aquitards that would inhibit upwards movement of the injected CO_2 [18]. The variability of the formation permeability has been modeled based on measurements from drillstem tests performed in the course of petroleum exploration in the area [18]. The permeabilities are log-normally distributed with a median (or geometric mean) of 6.28 md[**]. The temperature and pressure gradients for the formation are modeled based on studies of the Alberta Basin [18], and are within the ranges of temperature and pressure gradients observed in other sedimentary basins [4]. Monitoring and verification costs for the storage model are based on ranges presented by various authors at recent conferences [22, 23], and the site screening and evaluation costs are based on those presented by the Battelle Memorial Institute [24]. The site screening and evaluation costs presented by Battelle [24] were developed based on injection of CO_2 for CCS being regulated under the Underground Injection and Control (UIC) program as a Class I (i.e., "no migration") well [25].

Table 1. Case study input parameters and distributions for the transport and storage models.

Parameter	Rep. Value	Distribution	Min	Max	Mode	Mean[††]
Design CO_2 Mass Flow (Mt/y)	4.67	Uniform	3.00	5.00	-	4.00
Power Plant Capacity Factor (%)	75	Triangular	15	90	75	60
Fixed Charge Factor (%)	15%	Uniform	10%	20%	-	15%
Pipeline Transport Model Parameters						
Inlet Temperature (°C)	5.6	Constant	-	-	-	-
Inlet Pressure (MPa)	13.79	Constant	-	-	-	-
Outlet Pressure (MPa)	10.3	Constant	-	-	-	-
Total Pipeline Length (km)	30	Uniform	10	50	-	30
Pipeline Elevation Change (m)	0	Constant	-	-	-	-
Annual O&M Cost ($/km-y)	3,100	Triangular	2,000	5,000	2,300	3,100
Storage Model Parameters						
Injection Pressure (MPa)	10.3	Constant	-	-	-	-
Depth (m)	1480	Uniform	1460	1620	-	1540
Thickness (m)	14	Triangular	10	20	12	14
Horizontal Permeability (md)	6.28	Truncated Lognormal	1.84	2.00	-	6.28
Pressure Gradient (MPa/km)	8.4	Triangular	8	12	11.5	10.5
Temperature Gradient (°C/km)	30	Triangular	25	35	30	30
Permeability Anisotropy	0.3	Constant	-	-	-	-
Monitoring & Verification Cost ($/tonne-y)	0.05	Uniform	0.03	0.10	-	0.07
Site Screening & Evaluation (k$/site)	1,685	Uniform	843	2,528	-	1,685

Illustrative Case Study Results

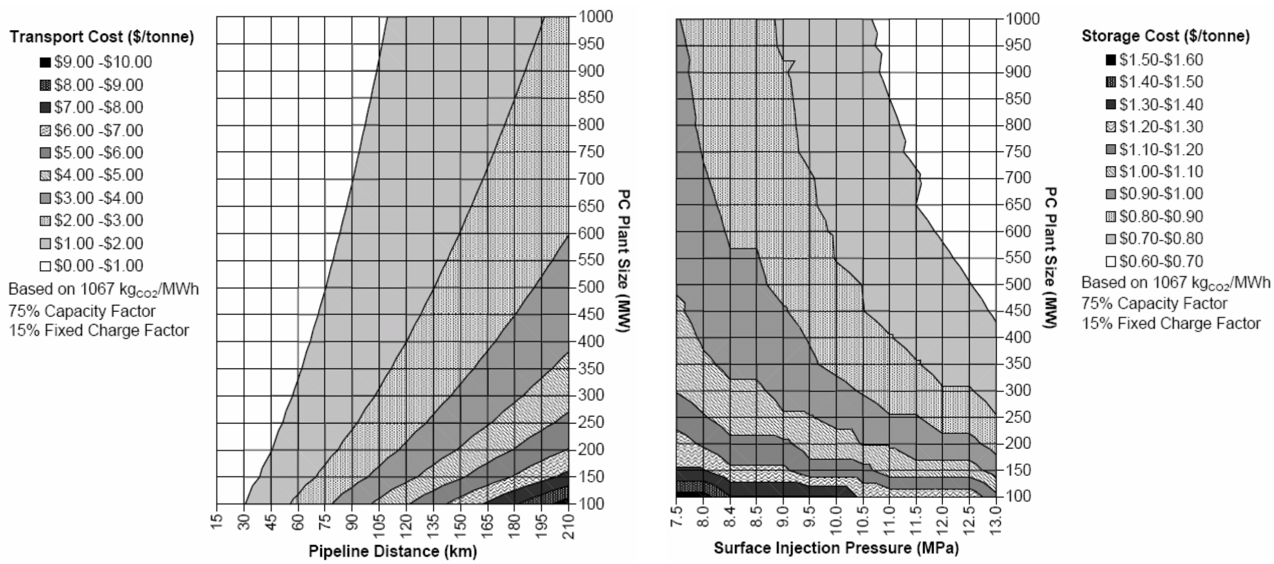
Evaluation of the pipeline transport model using the representative parameters listed in Table 1 results in a cost of $0.34 per tonne of CO_2 transported, 92% of which results from capital cost with the remaining 8% accounting for O&M. Because this case study assumes a short pipeline of only 30 km (at most),

[**] For the Monte Carlo analysis the permeability is modeled using a truncated lognormal distribution, with a minimum of 0.41 md and a maximum 103.9 md, which correspond to the minimum and maximum permeabilities as measured in the drillstem tests.
[††] In the case of the truncated lognormal distribution, this parameter is the geometric mean of the lognormal distribution or e^{μ}, where μ is the arithmetic mean of ln(X)

Figure 4 shows the cost surface that results from varying the pipeline length, as well as power plant size while continuing to assume that no booster stations are required along the pipeline.

Figure 4(a) shows that the cost of transport increases with distance, and decreases with power plant size. Moreover, the cost per tonne of CO_2 transported exhibits increasing returns to scale; that is, for a fixed distance the transport cost decreases non-linearly with plant size. For example, for a 200 km pipeline, the cost of transport for a 100 MW power plant is $8.96 per tonne, whereas for a 500 MW power plan the cost is approximately $3.17 per tonne, and for a 1000 MW power plant the cost decreases to approximately $2.04 per tonne. The values presented in Figure 4(a) compare well with values reported in other studies [26].

For the representative case study parameters in Table 1, the cost of geologic storage is $0.80 per tonne of CO_2 stored, injected through 25 wells into the aquifer. Again, to illustrate more general model results, the cost of geologic storage in dollars per tonne for coal-fired power plants of varying capacities injecting CO_2 into the representative aquifer defined in Table 1 is shown in Figure 4(b). The representative cost and range of costs presented in Figure 4(b) compare well with the ranges reported in other studies [4,8,10], although there are relatively few such studies in the literature.



(a) (b)

Figure 4. The transport cost surface (a) for a coal fired power plant with no booster stations, and the storage cost surface (b) for the same coal fired plant.

Figure 4(b) shows that the cost of storage decreases with increasing power plant size, and decreases with increasing surface injection pressure. However, Figure 4(b) illustrates only the cost of storage: the increasing cost of transport with increasing surface injection pressure may offset decreases in storage cost to some degree. The cost per tonne of CO_2 stored shows increasing returns to scale, much like the transport cost. Combining the representative result for the cost of transport with the result for the cost of aquifer storage presented here, the total cost per tonne of transport and storage is about $1.14 per tonne of CO_2 stored.

Sensitivity Analysis Results

The results of applying the probability distributions in Table 1 to the transport and storage model inputs are shown by the cumulative distribution functions shown in Figure 5. In Figure 5, the storage cost shows much greater variability than the transport cost given the uncertainty in the input parameters. Table 2 summarizes the results of the sensitivity analysis for transport, storage, and the total of the two costs.

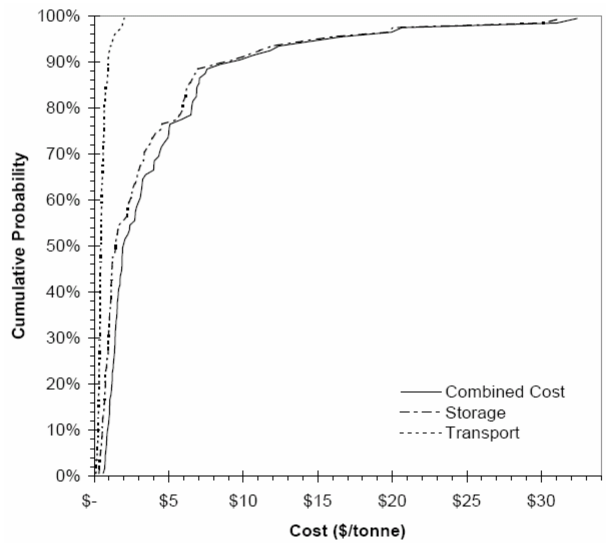


Figure 5. The cumulative probability distributions resulting from the Monte Carlo sensitivity analysis.

However, the degree to which the uncertainty in an individual input parameter contributes to the output is not clear from these results. Knowing which input parameters contribute most to the variability of the cost suggests where the greatest reduction in the cost estimate variability can be gained through a reduction in input uncertainty. In order to assess the relative contribution of uncertainty and variability to the cost calculated by the transport and storage models and, in turn, the total cost of transport and storage, Spearman rank-order correlation coefficients were calculated. The rank-order correlation coefficients are shown in Figure 6.

Table 2. Summary statistics for the transport, storage, and total costs calculated in the sensitivity analysis.

Statistic	Transport Cost ($/tonne)	Storage Cost ($/tonne)	Total Cost ($/tonne)
Mean	0.55	3.74	4.29
Median	0.44	1.44	1.94
Standard Deviation	0.35	5.49	5.56
95% Percentile	1.22	14.01	14.59
5% Percentile	0.21	0.44	0.78
Minimum	0.12	0.32	0.60
Maximum	2.03	31.30	32.40

The dotted horizontal lines above and below the abscissa in Figure 6 indicate the 95% two-tailed confidence interval for the calculated rank-order correlation coefficients. Thus, in this scenario the correlation between the cost of transport, storage, or the total cost is not statistically significant for the following parameters: annual pipeline O&M, reservoir depth, reservoir thickness, monitoring and verification cost, and site screening and evaluation cost. Of the significant correlations, the variability in the reservoir permeability has the largest effect on the variability of both the cost of storage and the total cost, while the uncertainty in the pipeline length has the largest effect on the variability of the cost of transport and a barely significant effect on the total cost. The power plant capacity factor has a significant impact on all of the cost estimates, as it determines the amount of CO_2 actually being transported and stored, as opposed to the design value used to size all equipment.

The contribution of uncertainty and variability of the input parameters to the cost calculated by the models will be affected by the distributions used to define the uncertainty and variability of the inputs. Thus, for a different scenario, the relative contributions may change. For example, if the model were applied to a specific source-sink paring (e.g. a 500 MW PC plant 100km from a storage location), there would not be uncertainty in the pipeline length and CO_2 mass flow rate, and the correlation coefficients of the remaining uncertain and variable parameters would likely increase. Moreover, the costs of transport and storage presented above do not reflect an estimate of the absolute or lowest cost of transport and storage for a power plant located in the Wabamun Lake study area. For example, the lowest combined cost of transport and storage might be located farther from the power plant, but have a more favorable permeability. Such tradeoffs between transport and storage costs would have to be evaluated in the context of a set of options for a particular power plant location.

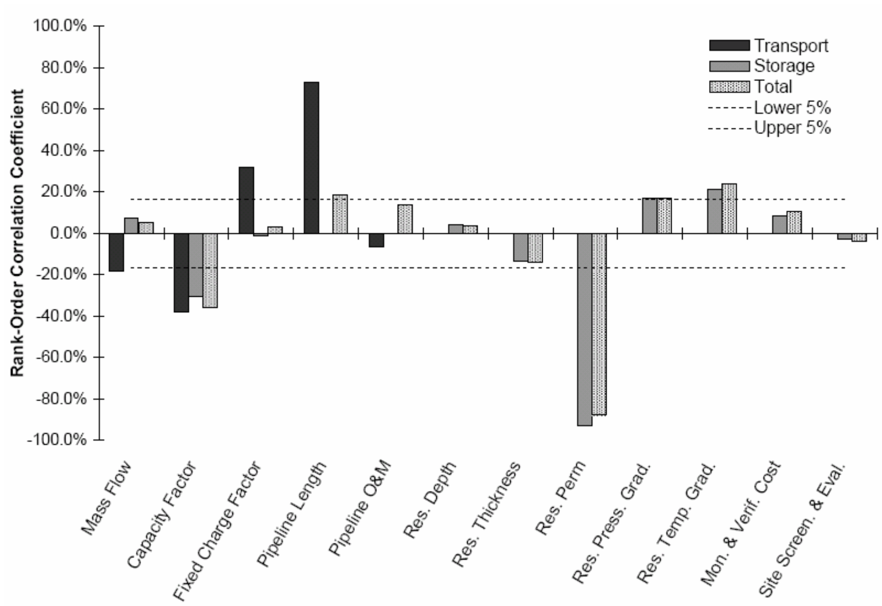


Figure 6. Rank-order correlation coefficients calculated between the transport cost, storage cost, and the total cost of CCS and the uncertain or variable input parameters.

Conclusion

Engineering-economic models of CO_2 transport and storage have been developed based on fundamentals of fluid flow in pipes and porous media, and historic costs from the petroleum industry. Applying the models to a scenario involving storage of CO_2 captured from a 500 MW coal fired power plant in the vicinity of Wabamun Lake in central Alberta, Canada with in a distribution of costs. The median cost for CO_2 transport is \$0.44 per tonne, for storage is \$1.44 per tonne, and the combined median cost of transport and storage is \$1.94 per tonne CO_2 stored. The cost of CO_2 storage is more variable than that of CO_2 transport, and the total cost varies from a 5th percentile of \$0.78 per tonne to a 95th percentile \$14.59 per tonne. Based on these results, the median cost of transport and storage is a small part of the total cost of CO_2 storage, but there will be cases in which the cost of transport and storage are large.

The uncertainty analysis has shown that the parameters which have the most impact on the variability of the transport cost are the length of the CO_2 pipeline and the amount of CO_2 to be transported, while the cost of injecting CO_2 is highly dependent on the permeability of the host formation. The cost of CO_2 transport increases with distance and decreases with pipeline capacity, resulting in economies of scale that are reached at high design capacities. The cost of CO_2 storage increases exponentially as permeability decreases and the cost of both transport and storage are decreased with increasing capacity factors. The significant dependence of transport and storage cost on reservoir parameters, transport distances, and capacity factors suggests that future studies should carefully consider these factors when citing general cost estimates.

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