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Carbon Storage Potential of North American Oil & Gas Produced Water Injection with Surface Dissolution

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Abstract: Carbon dioxide (CO₂) geological storage traditionally involves capturing a CO₂ stream from a point source such as a power station or from cement, steel, or natural gas processing plant, transporting it and compressing it, prior to injection as a supercritical phase into a suitable geological reservoir overlain by a cap-rock or seal. One of the main perceived risks in CO₂ geological storage is migration or leakage of the buoyant CO₂ stream through the seal, via faults or fractures, or other migration out of the storage complex. Injection of CO₂ dissolved in water may be one solution to mitigate the leakage risk. This approach could take advantage of large volumes of wastewater already being reinjected into saline aquifers worldwide but particularly in North America, thus reducing costs. This study examines the potential to “piggyback” off the existing wastewater injection industry as a novel carbon storage option.

Keywords: CO₂ storage; water reinjection; saline aquifers; surface dissolution



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1. Introduction

Permanent subsurface sequestration of CO₂ captured from power stations and industrial sources is one of the major options for reducing greenhouse gas emissions [1]. In addition to hydrocarbon reservoirs, saline aquifers are widely viewed as candidates for CO₂ sequestration. Saline aquifers provide very large storage capacity, are broadly distributed and underlie most CO₂ emission sources [2]. Numerous studies have examined the feasibility of CO₂ injection and storage in saline aquifers and references therein [3,4]. The injected CO₂, which is usually taken to be nearly pure, is trapped through different mechanisms, namely structural, residual, solubility and mineral trapping [1].

These processes may be tracked through various numerical modelling methodologies that have been developed to predict the extent of each trapping mechanism under different conditions of interest [5]. From a technical perspective, the injection, dispersion and trapping model forecasting capability is often affected by inadequate knowledge of relative permeability, which critically affects the quantity and distribution of the CO₂ plume, the impacted subsurface volume, and the degree and extent of the different trapping mechanisms in a multiphase system. Current measuring methods for relative permeability fail to cope satisfactorily with the heterogeneity, very high mobility ratios and varied capillarity forces in this system [6–8]. Economically, the high cost associated with CO₂ capture, separation, compression, transportation and injection is another key hurdle for more rapid deployment of CO₂ geological sequestration globally [9].

In most large-scale global carbon storage schemes, the CO₂ is injected as a supercritical fluid, which is less dense than the native formation water and rises up in the storage

formation due to its buoyancy, until a geological top seal layer is reached. The CO₂ pools and is retained under the seal layer, which provides either a structural trap [10] or a regional seal under which the CO₂ plume slowly migrates up-dip. In either case, a significant concern and risk is then the integrity of this seal.

An alternative is to saturate water or brine with CO₂ at the surface prior to injection [11–13]. This changes the dominant trapping mechanism from “structural” and “residual” to more stable “solution trapping”. Importantly, the saturated brine is often slightly denser than the virgin reservoir fluid [14]. The tendency is, therefore, for the plume to sink. Thereby, this approach significantly reduces leakage risk compared with storage of supercritical CO₂ in reservoir formation water resulting in a multiphase system driven by buoyancy. Compared with direct injection of a CO₂ fluid, the method has been assessed as having higher capital and operating costs, but has the advantage of lower leakage risk and consequently much reduced long-term monitoring costs.

In this paper we examine the feasibility of using existing water reinjection (e.g., disposal of coproduced oil and gas reservoir waters or from enhanced oil recovery or other mining activities) as a potentially niche opportunity to provide low-cost carbon storage by presaturating the water with CO₂ prior to its injection.

Considerable amounts of water are reinjected in Canada and the United States each year, shown in Tables 1 and 2. For the United States, the total rate is ~599,000,000 m³/day and for Canada ~215,500,000 m³/day. The quantity of CO₂ that might be dissolved in the various locations depends on local conditions of temperature, injection pressure and water salinity. At a high level, this indicates the scale of the opportunity for carbon storage by this method. Obviously, the next stage of source sink matching would high-grade those locations best geologically suited with the shortest distance between source and sink, and this would greatly reduce the immediate carbon storage opportunity.

Clark and Veil [15] and Veil [16] reported that the TDS concentration of produced water in the western United States varies between 1000 mg/L and 400,000 mg/L, with median TDS concentration from most formations well under 100,000 mg/L.

In Alberta, produced water from conventional oil and gas production has very variable TDS with an average of ~30,000 mg/l and maximum of 329,000 mg/l [17].

Indicatively, the potential CO₂ reinjection using all this water equates to ~34,903,000 tCO₂/y for the United States and ~12,556,000 tCO₂/y for Canada. These indicative amounts are based on an average salinity of 30,000 mg/L, injection pressure of 16,560 kPa (depth 800 m and 90% of 23 kPa/m) and temperature of 24 °C. Clearly, there exists a considerable opportunity to codispose of CO₂ dissolved in water that is already being injected into subsurface saline aquifers. Since many of the costs of water injection are consequently already sunk, piggy-backing CO₂ disposal may provide a cost-effective sequestration option.

Table 1. Produced Water Volumes and Number of Injection Wells for Regions in the United States in 2012, Modified From [16].

Field Name	Volumes m ³ /Year	Injection Wells
Alabama	4,584,938	83
Alaska	10,095,110	64
Arkansas	16,845,018	640
California	74,288,290	970
Colorado	14,772,648	292
Florida	1,784,466	7
Indiana	1,714,328	208
Kansas	93,570,453	3523
Louisiana	102,238,847	3231
Michigan	11,924,047	710

Table 1. *Cont.*

Field Name	Volumes m ³ /Year	Injection Wells
Mississippi	12,407,716	494
Montana	6,741,390	no data
Nebraska	2,236,986	113
Nevada	565,538	10
New Mexico	45,449,739	no data
North Dakota	19,314,300	350
South Dakota	270,841	15
Ohio	1,688,193	190
Oklahoma	129,623,927	4021
Pennsylvania	503,198	no data
Utah	10,199,134	118
West Virginia	462,171	64
Virginia	385,327	4879
Wyoming	37,315,578	335
Total	598,982,186	20,317

Conversion factor 1 bbl/day = 0.12 m³/day and 360 days = 1 year.

Table 2. Top 10 Largest Injection Fields, Injection Volumes and Number of Injection Wells in Alberta, Canada, in 2006 (modified from [17]).

Field Name	Volume m ³ /Year	Injection Wells
Provost	22,100,000	130
Redwater	20,900,000	50
Hayter	19,200,000	35
Grand Forks	16,700,000	63
Bellshill Lake	15,600,000	19
Jenner	14,400,000	19
Bow Island	13,500,000	27
Bantry	12,600,000	28
Enchant	12,200,000	22
Killam	11,600,000	13
Rainbow	10,800,000	16
Taber North	9,420,000	27
Taber	8,870,000	24
Fenn-Big Valley	8,340,000	18
Hays	5,970,000	14
Lindbergh	5,170,000	14
Mitsue	4,330,000	10
Fort Saskatchewan	3,400,000	3
Sturgeon Lake	377,000	8
Total	215,477,000	130

2. Economic Analysis

Power plants, oil sands operations and many other production facilities are under pressure to reduce CO₂ emissions. CO₂ capture and storage (CCS) provides the single largest potential for CO₂ emissions reduction, and saline aquifers and hydrocarbon reservoirs for enhanced recovery are obvious first choices as potential repositories. However, based on the CCS Development Council [18], it is desirable that CO₂ storage operations be at least 800–1000 m deep. In addition, the great majority of oil and gas reservoirs, still in production, are underlain by deep saline aquifers such that storage of CO₂ in these aquifers may materially impact oil and gas production; consequently, these aquifers or portions thereof may be excluded for CO₂ storage in the near term. In Northern America, Ghaderi and Leonenko [19] reported that the typical benchmark of one megaton of CO₂ storage a year (1 Mt/y) over 50 years is used in academic research and commercial projects that are currently in place or under review.

Here, we examine the added compression and transportation cost of bringing CO₂ to different locations from a point source emitter and installing CO₂–water surface mixing operations (Figure 1). In keeping with the potential opportunity where water recharge into the aquifers is already in operation for other reasons, we assume that the injection setup already exists.

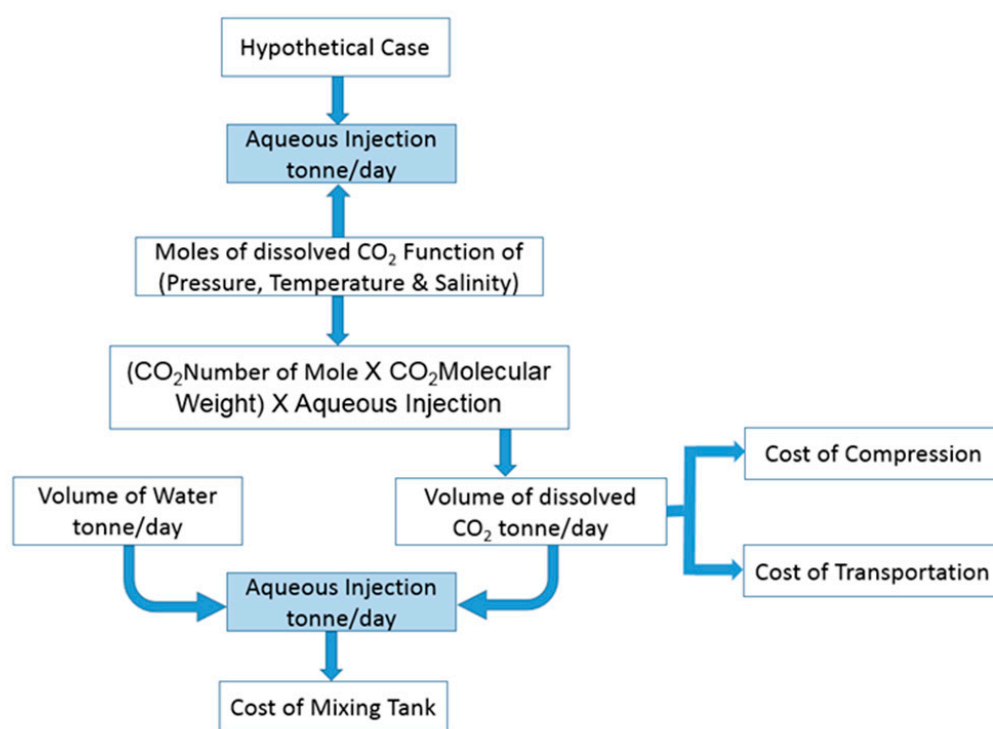


Figure 1. Illustrative scheme of cost calculation elements of CO₂, brine and aqueous injection.

2.1. Surface Dissolution

CO₂ solubility in brine is a function of pressure, temperature and salinity. The CO₂ solubility decreases with increasing salinity and temperature, and increases with increasing pressure. Figure 2 shows the solubility of CO₂ at different conditions that can reasonably be considered for the surface dissolution facility. The solubility is calculated using a CO₂–Brine phase equilibria model of Zhao et al. [20], matching the other studies [21–23].

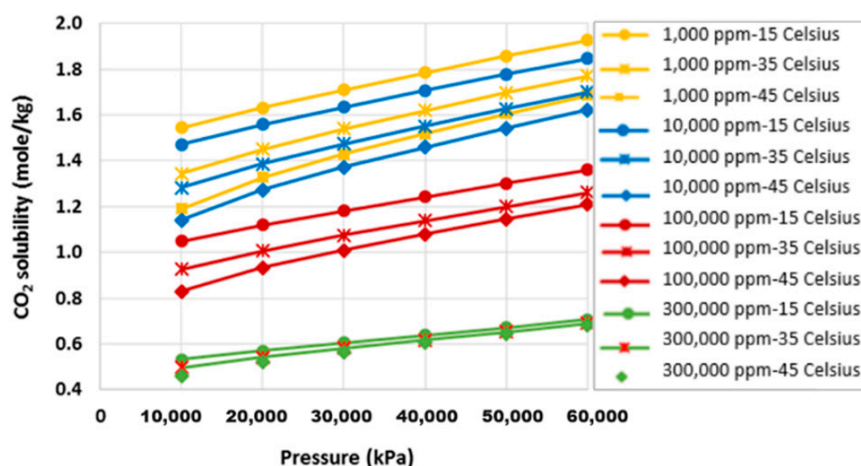


Figure 2. CO₂ solubility as a function of pressure, temperature and salinity, generated using Zhao et al. [20].

Figure 2 illustrates CO₂ solubility at different conditions covering pressure values for aquifer injection at depths of 500–3000 m, assuming 90% of fracture pressure gradient of 23 kPa/m; salinities of 1000, 100,000 and 300,000 ppm covering the wide range of values reported in American and Canadian situations; and surface temperatures of 15, 30 and 45 °C. Solubilities at other conditions are easily obtained applying the model of Zhao et al. [20].

The CO₂ to be injected is dissolved in the injection water at the surface, so for given surface conditions the number of moles CO₂ dissolved in 1 kg of water (e.g., from Figure 2) and maximum well water injection rate (from Tables 1 and 2) are by:

$$V_{\text{aqueous}} = V_{\text{brine}} + V_{\text{CO}_2} \quad (1)$$

At the surface conditions, mass of dissolved CO₂ at the injection stream is given by;

$$V_{\text{CO}_2} = \left[(V \times \rho)_{\text{aqueous}} \times (n \times mw)_{\text{CO}_2} \right] \quad (2)$$

where V is volume, ρ is density, n is number of mole, mw is molecular weight, $\rho_{\text{H}_2\text{O}}$ and ρ_{brine} are taken for simplicity to be 1000 kg/m³.

The rate at which CO₂ dissolves into the brine determines the size of the surface mixing vessel. This depends on how the CO₂ is dispersed in the water, for example, through a distributor arrangement that injects the CO₂ as small bubbles or droplets into the brine, or using an agitator within the tank, or even an inline mixer. Burton and Bryant [11] and Eke et al. [12] suggested that 90% of CO₂ dissolution can occur within a residence time of 9–12 min even without agitation.

The dissolved CO₂ in water generates carbonic acid, a fluid with corrosion potential, creating possible issues for common carbon steel materials [11,12]. Carbonic acid can be corrosive to piping, valves, seals, and O-rings, so design precautions for surface equipment and injection wells are necessary. Although it is costly, Eke et al. [12] suggested that stainless steel materials should be employed for corrosion resistance in the injection station construction. Alternatively, and perhaps more cheaply, the issue may be managed by corrosion inhibitors, chemical neutralisation or buffering, depending on the water chemistry. However, there is some advantage to retaining a low pH insofar as dissolution may be enhanced in the near wellbore region of the injection formation, improve injectivity and benefit the injection strategy.

The mixing tank costs are related to the mixing pressure of the tank, the flow rate of the injection and the residence of time. The following parameters ($t_r = 4$ min, $F_S = 3$ and $R = 0.6$ m) and equations are used to estimate the mixing tank costs [11];

$$\sigma_{yield} = \frac{P_{mixing} \times r \times F_S}{T} \quad (3)$$

σ : Yield stress of steel, 30,000 psi, P_{mixing} : mixing tank pressure psi, r : radius of mixing tank ft, F_S : Factor of Safety, T : mixing tank wall thickness ft.

$$volume\ of\ tank = \pi r^2 L = (q_{brine+CO_2}) \times t_r \quad (4)$$

R : radius of mixing tank “ft”, L : length of mixing tank “ft”, $q_{brine+CO_2}$: injection rate “ft³/day”, t_r : residence time “minutes”.

$$price\ of\ tank = \frac{\$0.6}{lbm} \times \frac{0.28lbm}{in^3} \times 2\pi rTL \quad (5)$$

where T , r , L are in inch units.

2.2. Compression Cost

The allocation of CO₂ separation (capture) and compression costs depends on where the system boundaries are taken. Separation costs depend on the source, purity, technology and other factors for which there is an extensive literature. Since this cost is necessary and essentially the same whatever method of CO₂ sequestration/storage is applied, we disregard it from the current analysis. Regarding supply to the reinjection site, if the CO₂ is already available at pipeline pressure then only the added costs of transporting the CO₂ to the “new” site need to be incorporated (i.e., additional pipeline plus a booster pump to overcome the additional line pressure losses). We consequently separate CO₂ compression (which uses a large amount of energy and relatively expensive capital equipment) and pumping (which uses comparatively much less energy and simpler equipment). This recognizes that in some situations compression may be necessary but not in others. We disregard the water pumping costs, which we take to be already sunk, since the CO₂ sequestration is simply an add-on to an existing waste-water injection.

Cost of compression is calculated following the procedure of McCollum and Ogden [24], with some updated equations and calculation procedures, explained in Dawson et al. [25].

$$W_{s,t} = \left(\frac{1000}{24 \times 3600} \right) \times \left(\frac{mZ_sRT_{in}}{M\eta_{is}} \right) \times \left(\frac{K_s}{K_s - 1} \right) \times \left[(CR)^{\frac{K_s-1}{K_s}} - 1 \right] \quad (6)$$

where “ m ” is CO₂ flow rate (t/day), “ Z_s ” is average CO₂ compressibility for each individual stage, “ R ” is the gas constant (8.314 kJ/kmol-K), “ T_{in} ” is CO₂ temperature at the compressor stage inlet (K), “ M ” is the molecular weight of CO₂ (44 kg/kmol), “ η_{is} ” is isentropic efficiency of the compressor, “ K_s ” is the average ratio of specific heat of CO₂ for each individual stage, “ CR ” is compression ratio of each stage.

$$W_p = \left(\frac{1000 \times 10}{24 \times 36} \right) \times \left(\frac{m(P_{final} - P_{cut-off})}{\rho\eta_{is}} \right) \quad (7)$$

where “ W_p ” is pumping power requirement (kW), “ ρ ” is the average density of CO₂ during pumping (630 kg/m³), “ η ” is efficiency of the pump, $P_{cut-off}$ is the CO₂ critical pressure, P_{final} is the desired injection pressure.

$$C_{comp} = m_{train} \times N_{train} \left[\left(0.175 \times 10^6 \right) \times (m_{train})^{-0.71} + \left(1.886 \times 10^6 \right) \times (m_{train})^{-0.6} \times \ln \left[\frac{P_{cut-off}}{P_{initial}} \right] \right] \quad (8)$$

$$C_{pump} = \left[\left(1.495 \times 10^6 \times \frac{W_p}{1000} \right) + 0.07 \times 10^6 \right] \quad (9)$$

where “ C_{comp} ” is capital cost of compression, “ C_{pump} ” is capital cost of the pump, and “ m_{train} ” is the CO₂ mass flow rate through each compressor train (kg/s).

2.3. Transportation Cost

Compressed CO₂ is transported through pipelines. There are a variety of capital costing models for CO₂ pipelines in the literature; a convenient one for scoping purposes is provided by McCollum and Ogden [24] based on that it is a function only of CO₂ mass flow rate (m) and pipeline length (L), avoiding the complexities of more advance pipeline diameter calculations.

$$C_{cap} = 13,400 \times (m^{0.35}) \times (L^{0.13}) \quad (10)$$

$$C_{total} = F_L \times F_T \times L \times C_{cap} \quad (11)$$

where “ L ” is pipeline length (km), “ F_L ” is location factor; “ F_T ” is terrain factor.

3. Economic Analysis

Here, three examples are presented to provide a sense of the CO₂ sequestration costs associated with water reinjection. The depth of the reservoirs for carbon storage is taken as 1000 m, maximum bottom hole injection pressure 20,700 kPa (using 90% of fracture pressure gradient of 23 kPa/m), constant surface temperature of 240C and average salinity of 100,000 ppm. Under this condition, 1.052 moles/KgH₂O of CO₂ is expected to dissolve in the surface mixing tank (e.g., 4.6% of the injection stream (Aqueous) is dissolved CO₂).

A typical water reinjection well operates at ~1500 t/day and we use this as a basis. The actual rate depends on site conditions, depth of the injection target and permeability amongst others. Most reinjection sites have multiple injectors and, once the optimal rate has been established, it is typically cheaper to drill additional wells rather than increasing the injection rate per well.

For annualising the costs, a capital recovery factor of 15% of the cost components, 4% operation and maintenance (O&M) factor for compression and 2.5% O&M factor of capital cost for transportation.

The cases are: 1500 t/day injection rate, typical for a single well and corresponding to ~25,000 tonnes/year of CO₂; 69,000 tonnes/day injection rate, a moderately sized field corresponding to ~1,150,000 tonnes/year CO₂ and about 46 injection wells; and 350,000 tonnes/day injection rate, a very large operation corresponding to ~6,000,000 tonnes/year CO₂ and using 240 injectors.

The following Figure 3 shows the total power requirement for the compression and pump over a range of flow rates (typically, CO₂ rates of 69 tonnes/d, 3194 tonnes/d and 16,200 tonnes/d, for aqueous injection rates of 1500 tonnes/d, 69,000 tonnes/d and 6,000,000 tonnes/d, respectively). The power requirement for the compressor and pump is a linear function of the given CO₂ injection rates.

The electric power cost of both the compression and pump is 15.15 \$/tonne (considering electricity price of \$0.14/kWh). It would make up an increasingly larger percentage of total costs as electricity becomes more expensive. Figure 4 shows the total capital costs and operation and maintenance (O&M) costs of both compression and pump.

As expected, the capital and O&M costs become a smaller percentage of total cost as the CO₂ flow rate increases. The total cost is dominated by compression compared to the pump, though it may be noted that this is necessary for any CSS operation and does not represent an “added cost” for using the water reinjection sites.

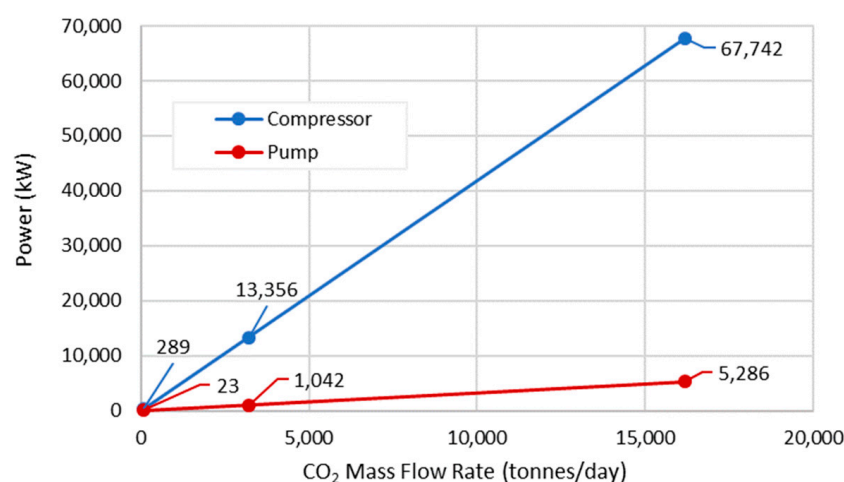


Figure 3. Power requirement of compression and pump as a function of CO₂ mass flow rate.

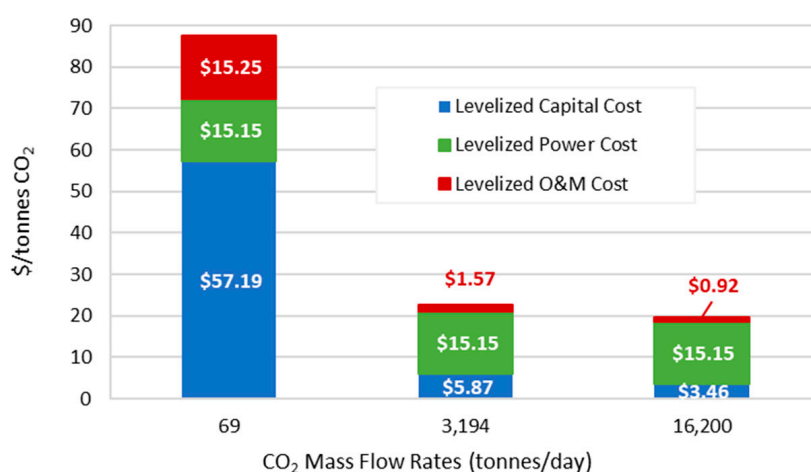


Figure 4. Contribution of capital, O&M, and power to total levelized cost of CO₂ compression/pumping as a function of CO₂ mass flow rate.

There is obviously a large advantage in minimising the distance for pipelines to transport the CO₂ to the injection site. To account for required CO₂ transportation from source to site, three different distances, 100 km, 300 km and 500 km, are considered. Figure 5 shows the total levelized costs (e.g., Capital and O&M) over a range of CO₂ mass flow rates and pipeline length. In the transportation cost calculations, location factor (L_F) and terrain factor (T_F) of 1 were considered, respectively.

The cost of a mixing tank represents the only extra cost for using aquifer recharge for CCS. In this study, we considered a typical water reinjection well operates at ~1500 t/day. Based on the Burton and Bryant (2009) cost model, the cost of mixing tank solution for a fluid (Aqueous) injection rate of 1500 tonnes/day and mixing pressure of 20,700 kPa is ~\$26,000 (see Equations (3)–(5)). This is insignificant compared to the costs associated with separating, compressing and transporting the CO₂ to the injection location. These extra costs are offset against very much reduced requirements for long-term site monitoring and risk insurance.

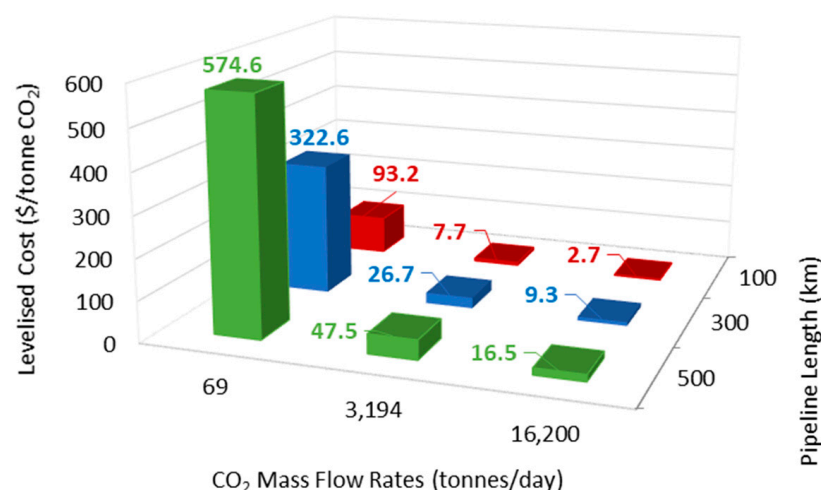


Figure 5. Levelized cost of CO₂ transport as a function of CO₂ mass flow rate and pipeline length.

4. Conclusions

Based on the data compiled here, there seems to be significant opportunity for CO₂ sequestration using co-injection of dissolved CO₂ where large volumes of wastewater are already being reinjected into aquifers. There seems to be ample scope, no significant technical barriers and the economics may prove attractive in many circumstances (mainly depending on the distance to CO₂ point source emissions). Although the proposed strategy may be more expensive in terms of specific CO₂ injection in \$/tonne, this can be offset by reducing the risk of CO₂ leakage from the formation and the associated long-term monitoring, risk and compliance costs. Importantly, produced water management practices often rely on injection into aquifers for water disposal and these activities already exist across the United States, Canada and other countries, so long distance additional transport lines should not be necessary.

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