GHGT-12

The relationship between \( kh \) and achievable rates of injection, and repercussions for large scale storage

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Abstract

Geologic CO\(_2\) storage (GCS) can provide meaningful reduction of CO\(_2\) emissions if implemented with large injection rates. The traditional paradigm for GCS entails injection of supercritical CO\(_2\) into a brine-filled formation with an implicit assumption that resident brine can be displaced through boundaries of the formation without adverse effects. In this paradigm, \( kh \), the product of permeability and formation thickness, is the first order control on achievable injection rates, and the gradual buildup of pressure in the formation during the storage operation will reduce those rates. These two factors impose serious constraints on the overall storage rate. In contrast, examination of field-aggregated injection and production volumes during waterflooding operations in oil reservoirs reveals a notable lack of correlation between \( kh \) and achieved injection rates. This suggests that if CO\(_2\) storage projects are operated in the same manner as waterflooded oil reservoirs, i.e. with both injection and extraction wells, located and operated to maximize rates, then material rates of storage can be achieved regardless of reservoir \( kh \). When applied to a large set of storage formations, this mode of operation provides an otherwise unattainable overall rate of storage while greatly reducing risks associated with elevated pressure in storage regions.

Keywords: injectivity index; productivity index; waterflood; time-weighted; storage capacity

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1. Introduction

1.1. Achievable injection rates for conventional GCS

A large fraction of the current rate of 35 Gt/y (35 × 10^9 metric tons per annum) of global CO_2 emissions to the atmosphere comes from fixed sources amenable to carbon capture. Geologic CO_2 storage (GCS) can provide meaningful reduction of emissions if implemented at overall rates of order Gt/y CO_2. Empirical evidence for the technical feasibility of achieving such rates exists: current global oil production exceeds 4 Gt/y, and the even larger volumes of water produced along with that oil are being re-injected into reservoirs at correspondingly larger overall rates. The structures into and from which these fluids are moving are similar to brine-filled structures that would be good candidates for GCS. Thus the key question to be addressed is whether GCS can achieve this scale of overall storage rates using the conventional storage paradigm. By “conventional” we mean the construction of wells into brine-saturated structures through which CO_2 is injected, with the accompanying presumption that the native brine is displaced by the CO_2 without adverse effect on other resources.

The analysis of this question for conventional storage is not encouraging [1]. A set of more than 1200 representative structures with a total pore volume equivalent to 34 Gt CO_2 would be capable of storing CO_2 at an overall rate of 0.1 Gt/y for only 50 y. Though 85% of the storage volume would still be available after 50 y of CO_2 injection, it would no longer possible to maintain the target overall rate using the given set of structures. The reasons are twofold: many of the structures with high injectivity will have already been filled within 50 y, and all of the structures will have elevated reservoir pressure. The remaining structures will have ample pore space but collectively will not have adequate injectivity to accommodate 0.1 Gt/y CO_2. Thus additional reservoirs would have to be acquired at an ever faster pace to maintain the overall storage rate beyond 50 y.

This problem of “time-weighted storage capacity” becomes more severe as the target storage rate increases. For example an overall storage rate of 0.2 Gt/y can be sustained in the same set of 1200 structures for only 17 y, and an overall rate of 0.3 Gt/y can be sustained for just 9 y [1]. Thus the required number of simultaneously operating storage projects increases nonlinearly with the target overall storage rate. Moreover the overall storage efficiency decreases, in that the fraction of unused pore space in a set of structures at any given time increases with the overall rate. It should be kept in mind that these results are based on extremely optimistic assumptions about CO_2 injectivity and sweep efficiency; more realistic assumptions drive the achievable overall rates even smaller, raising serious doubts about the feasibility of Gt/y storage rates [2].

These limitations arise for two reasons. First, the range of \(kh\) values for this set of structures is wide; see the cumulative frequency distribution in Figure 1. Because injection rate is proportional to \(kh\), the time needed to fill some structures can be hundreds or even thousands of times longer than for other structures, all else being equal. Second, the displacement of brine from a structure requires the gradual buildup of pressure in the structure. Because injection pressure is limited by the pressure at which fractures begin to propagate into the formation from the injection well, the available driving force for injection declines as more CO_2 is injected. This decline in driving force also means that attempting to compensate for small \(kh\) by constructing more wells reaches a point of diminishing returns quite soon. Thus for any set of structures like those represented in Figure 1, the requirement of maintaining a steady overall rate of storage becomes increasingly difficult and inefficient as storage continues. Ever more structures must be operating at any given moment to keep up with the rate requirement, and less of the pore space in those structures will be used over the decades-long course of a large-scale GCS program.

One way to overcome these limitations could be simply to select structures with much better than average injectivity. For example, the top decile of the structures in Figure 1 have a median permeability of 1.3 Darcy and a median thickness of 150 ft and account for 20% of the total pore volume in the set. Clearly a set of 1200 structures with properties like these would enable much larger sustained overall storage rates than the set of structures discussed above. The trade-off for this selectivity is likely to be a greater cost of transporting the CO_2, as the geologic environment that leads to these preferred structures (thick accumulations of unconsolidated or poorly consolidated sand beneath a good seal) is not ubiquitous. The greater thicknesses will also decrease the volumetric sweep efficiency of the injected CO_2, substantially reducing the storage capacity. The broader implication of this approach is that it requires refining catalogs of storage capacity to account for the expected injectivity of the
formations comprising that capacity. The refinement may lead to a significant reduction in storage capacity that can be accessed on the time scale of a few decades.

Fig. 1. Cumulative frequency distribution of permeability-thickness product for more than 1200 commercially developed oil reservoirs in the USA shows a wide range of values, spanning nearly four orders of magnitude.

1.2. Achievable injection rates for oil reservoirs

Given the challenges inherent in the conventional storage paradigm, it is of interest to consider whether a scalable and widely deployable approach can be developed by applying basic reservoir engineering principles. Here it is important to note that even the bottom decile of the structures in Figure 1 have been developed as commercially viable projects. It is impractical and uneconomic to attempt to compensate for smaller $kh$ by constructing proportionately more production wells, especially across the several orders of magnitude variation in Figure 1. This suggests that broadly comparable production rates per well have been achieved in these structures. If so, this has useful implications for CO$_2$, namely that roughly comparable injection rates per well can also be achieved in a set of structures with widely varying $kh$.

In this work we test these hypotheses using field-aggregated production volumes, injection volumes and counts of active wells for over 100 oil reservoirs. In subsequent sections, we describe the data available, propose a simple measure which directly accounts for overall flow rates and indirectly serves as a proxy for $kh$, and examine trends in that measure with time and with respect to variations in $kh$. The results strongly suggest that extraction wells will be essential for achieving sustained material rates of CO$_2$ storage.

<table>
<thead>
<tr>
<th>Nomenclature</th>
<th>Description</th>
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<tbody>
<tr>
<td>$C_i$</td>
<td>lumped factors in well injectivity index other than $kh$</td>
</tr>
<tr>
<td>$C_p$</td>
<td>lumped factors in well productivity index other than $kh$</td>
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<tr>
<td>$D$</td>
<td>depth of reservoir, ft</td>
</tr>
<tr>
<td>$g$</td>
<td>gravitational acceleration, m/s$^2$</td>
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<td>$k$</td>
<td>average permeability of a reservoir, mD</td>
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<td>$k_{r,w}$</td>
<td>relative permeability of aqueous phase, --</td>
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<tr>
<td>$k_{r,o}$</td>
<td>relative permeability of oil phase, --</td>
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<tr>
<td>$h$</td>
<td>average thickness of a reservoir, ft</td>
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<tr>
<td>$II$</td>
<td>injectivity index of a well, bbl/d/psi</td>
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<tr>
<td>$PI$</td>
<td>productivity index of a well, bbl/d/psi</td>
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<tr>
<td>$P_i$</td>
<td>average per well injection rate for waterflooded reservoir, bbl/d/psi</td>
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<tr>
<td>$P_p$</td>
<td>average per well rate of total fluids production for waterflooded reservoir, bbl/d/well</td>
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<tr>
<td>$P_{bh}$</td>
<td>bottomhole pressure of injection or production well, psi</td>
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2. Method

2.1. Waterflooding data for oil reservoirs

The California Department of Conservation maintains a large oil and natural gas database. The database includes injection, production, and, in some cases, geological data for California oil and natural gas fields. The online data extends backwards in time to the 1970s. Many of the reservoirs began operation long before the 1970s, but for the purposes of examining the relation between $kh$ and injectivity it is not necessary to have data from the outset of production.

Some reservoirs contain only production data, presumably because they have only ever been on primary production. Many have water injection data; others have gas injection data. For simplicity in interpreting the data, we only consider reservoirs that have extensive duration of water injection (usually decades) and no gas injection. These data were used to investigate the relationship between $kh$ and proxies of injectivity to be defined below.

For each reservoir selected, the database has monthly injection volumes $V_{\text{inj},w}$ and production volumes of oil and water $V_{\text{prod},o}$ and $V_{\text{prod},w}$. We are concerned only with overall capacity of the reservoir to produce fluids or to accept injected fluids, so we lump together the produced fluids into a single volume $V_{\text{prod}} = V_{\text{prod},o} + V_{\text{prod},w}$. We make no correction for the formation volume factor of the oil phase. The formation volume factor is typically between 1.0 and 1.5, so accounting for it would change the results by less than a factor of two. The correction would be much smaller for most of the data for the mature reservoirs, which produce much more water than oil. Given the other simplifying assumptions that will be made, this correction can be regarded as negligible.

For each month the database also reports the number of injection well-days and the number of production well-days of operation. The number of well-days is the sum of the number of days each well of a given type (injection or production) was operating during that month. For example, if during the month of September three production wells operated for 30 days each and a fourth producer operated for 10 days, the number of production well-days in September is $3 \times 30 + 10 = 100$.

2.2. Data for example waterflood

The values of $V_{\text{inj},w}$ and $V_{\text{prod}}$ for an example reservoir are plotted against injection well days and production well days respectively in Figure 2. The color of each point indicates the chronology; the earliest datapoint is red, the latest blue, and intermediate points are a scaled shade of purple.
The physical interpretation of Figure 2a is that at early times (red points near the origin) the number of production wells was relatively small (a few tens of wells) and the number of well-days per month was correspondingly small (a few hundred well-days). Because the number of well-days is small, the total production in a month is also modest, (a few thousand barrels). As the field is developed and more production wells are brought on stream, more fluids are produced each month and the number of production well-days also increases. These are the bluish-red points between 3000 and 6000 well-days. The red to bluish-red points form a linear trend. This suggests that each well has a similar productivity index ($PI$) and that the driving force for production (pressure drawdown between reservoir and bottomhole of each well) is similar for each well. In other words, each new well produces at similar rate.

The purple points (between 6000 and 15000 production well-days in Fig. 2a) and the purple-to-blue points (between 15000 and 18000 production well-days) all correspond to months when water was injected into the reservoir. Figure 2b shows the injection volumes in this period as a function of injection well-days. (Because injection started long after production, the origin of the x-axis in Fig. 2b (injection well-days) corresponds to a different absolute time than the x-axis in Fig. 2a (production well-days). The color of the points has the same meaning in both plots.) Each purple point has similar values of monthly production volume and injection volume (700,000 to 1,500,000 bbl), suggesting the reservoir was being operated so that voidage was zero (each produced barrel was replaced by an injected barrel). The most recent data (blue points) indicate that more fluid is being injected each month (3,000,000 bbl) than is being produced (2,500,000 bbl), suggesting that the operator is trying to increase the reservoir pressure.

The cluster of reddish-purple to purple points in Fig. 2a between 5000 and 8000 production well-days suggests that the rate of fluids production from each well decreased with time during this period: the darker points fall below the redder points. This would be consistent with the onset of water production at the producers and the consequent reduction in relative permeability for each phase. As the number of well-days increased (because more production wells were brought onstream) the total fluids produced also increased, with a slope a little smaller than the slope at earliest time (the red points). As injection continued and still more production wells were brought on stream (blue points) the slope of the points in Fig. 2a increased. This would be consistent with an increased driving force for production as the reservoir pressure increased.

The slope of the points for the injection data, Fig. 2b, at any given time is larger than for the production data, implying injection rates for an average well are larger than the total fluid production rate for an average well. This would be consistent with larger injection pressures and/or smaller mobility of the produced fluids (larger viscosity of
the oil, relative permeability effects for both phases). At later times (blue points) the slope of the injection data increases, indicating still larger per well injection rates than at earlier times in the waterflood.

2.3. Proxies for well productivity and injectivity indices from waterflood data

The preceding considerations lead us to define two quantities $P_i$ and $P_p$:

$$P_i = \frac{V_{inj \ w}}{injection \ well \ days} \quad (1)$$

$$P_p = \frac{V_{prod}}{production \ well \ days} \quad (2)$$

Physically these quantities are volumetric rates for the notional average injection or production well in a reservoir, with units of barrels of liquid per well per day. We thus derive from the database a month-by-month time-series of each quantity.

The ratio of $y$ value to $x$ value for each point in Fig. 2a and 2b provides a value of $P_p$ and $P_i$, respectively. The value of $P_p$ is close to 100 bbl fluid/well/day for most of the production history (red through purple points), increasing to nearly 150 bbl fluid/well/day late in the production history (blue points). The value of $P_i$ remains fairly close to 400 bbl water/well/day for the entire injection history. The absence of large, systematic variation in $P_i$ and $P_p$ over time is typical of the reservoirs in this study. Thus for our purposes it is sufficient to characterize each reservoir with a single average value of $P_i$ and $P_p$. Some reservoirs show more scatter than in Fig. 2, so we also extract upper and lower bounds on $P_i$ and on $P_p$ that represent the largest and smallest 20% of the points.

The quantities $P_i$ and $P_p$ are useful proxies for the conventional productivity or injectivity index for wells in a reservoir. The indices are conventionally defined as

$$I = \frac{Q}{\Delta P} \quad (3)$$

with $I$ replaced by $PI$ for production wells and by $II$ for injection wells. Here $Q$ corresponds to fluids produced or injected as appropriate, $\Delta P = \langle P \rangle - P_{bh}$ is the drawdown for production wells and $\Delta P = P_{bh} - \langle P \rangle$ is the injection overpressure for injectors, where $\langle P \rangle$ the average pressure in the reservoir. In this definition, the relation between $I$ and $kh$ is given for vertical wells and radial flow of a single phase fluid by

$$I = \frac{2 \pi}{\mu \left( \ln \frac{z_e}{r_w} - \frac{3}{4} \right)} \quad (4)$$

$P_i$ and $P_p$ represent an average value of $Q$ for injection wells and production wells respectively. The first-order influence of the permeability-thickness product on production/injection rates is clear from Eq. 4.

The values of $P_i$ ($P_p$) are good proxies for $II$ ($PI$) if the injection overpressure (drawdown) and effective mobility of injected (produced) fluid is similar for all the injectors (producers) in a reservoir. This is not an unreasonable approximation for a given reservoir. Though individual wells will certainly have different flowing pressures, the limits on injection pressure (drawdown) are typically the same across a field. Similarly, though water cut will vary from one producer to the next, the effective mobility of produced fluids varies within a defined range. Variations in reservoir thickness and permeability from well to well are likely to be as large as the variations in other properties influencing $II$ and $PI$. Though the level of aggregation of the data does not permit a more rigorous test of this proxy, we will see that the conclusions are not strongly sensitive to these approximations.

Formally, we assert that

$$P_p = P I \Delta P = 2 \pi \left( \frac{k_f r_w^2}{\mu} + \frac{k_i r_w^2}{\mu} \right) \Delta P k_h = C_p k_h$$
where $C_i$ and $C_p$ are constants that do not vary with time for a given reservoir. We wish to draw inferences about the influence of $kh$ on achievable rates from the values of $P_p$ and $P_i$ for a large set of reservoirs. To do this we must make a much stronger assumption, which is that $C_i$ and $C_p$ are the same for all reservoirs. In other words, $kh$ is the only factor influencing injectivity/productivity which varies between reservoirs. This assumption is based on our expectation that the other factors influencing injectivity/productivity (fluid mobilities, drainage radius, drawdown or injection overpressure) collectively do not vary widely between reservoirs, probably a range of about one order of magnitude, which is much less than the variation in $kh$. The smaller variability is partly due to simple flow physics: fluids with large mobility can be produced at commercial rates with smaller drawdowns. Thus the error introduced by assuming that the produce of drawdown and effective fluid mobility is the same for all reservoirs may not be severe, at least for the purposes of comparing injectivity and $kh$. Empirical support for this expectation is that the values of $P_p$ for our selected waterflooded reservoirs are systematically about an order of magnitude smaller than the values of $P_i$. This is consistent with produced fluids effective mobility being smaller than water mobility (because of oil’s greater viscosity) especially during two phase flow (oil and water both flowing) into production wells.

3. Results and Discussion

3.1. Correlation and dynamic range of proxies

Two runs of data analysis were made on a set of reservoirs with waterflood data and reported $kh$ values. On the first run, an attempt was made to compare injection and production data directly to $kh$. For each reservoir, representative values of $P_i$ and $P_p$ were obtained from plots similar to Fig. 2. Figure 3 shows the results. No correlation is evident between the measured quantities and $kh$. Perhaps more significantly, there is a significant discrepancy in the dynamic range of the two sets of variables. The range of values of each quantity $P_i$ and $P_p$ falls for the most part within two orders of magnitude, whereas $kh$ ranges across four orders of magnitude.

Fig. 3. Proxies for (a) injectivity index, Eq. 1, and (b) productivity index, Eq. 2, for waterflooded reservoirs show little correlation with permeability-thickness product. Slope of line indicates a first-order dependence that would be expected based on Eq. 1, 3 and 4.

The absence of correlation in Fig. 3 is remarkable. Even with the assumptions of constant $C_i$ and $C_p$, the reservoirs’ $kh$ should still have an observable first order influence on well-average rates. This influence should align points along a line with the same slope as the one sketched on each plot in Fig. 3. The narrower range of $P_i$ and $P_p$ is
consistent with the idea that reservoir engineering, e.g. placement of wells including areal density and vertical or horizontal layout; stimulation of wells, both producers and injectors, the latter by injection-induced fracturing; management of pressure gradients and reservoir pressures, etc., enables operators to override the intrinsic injectivity/productivity of their reservoirs to obtain commercially attractive injection/production rates. The absence of correlation can be attributed to engineering design; the narrower range is because economic competition and surface facility constraints drive operators toward a relatively narrow range of realized well-average rates.

For the second run, the two values of $P_i$ and $P_p$ representing upper and lower bounds are compared for a larger set (more than 100 reservoirs). Values of $kh$ were not reported for all of these reservoirs, so we compare these values with all of the $kh$ values reported for California oil fields. As shown in Figure 4 there is still much less variation of $P_i$ and $P_p$ compared with the variation in $kh$. Moreover the difference between the upper and lower bounds is small compared to the variation in $kh$. Thus using average values of $P_i$ and $P_p$ is sufficient for our purposes.

![Cumulative frequency distributions for upper (blue curve) and lower (green curve) bounds on proxies for (a) productivity index, Eq. 2, and (b) injectivity index, Eq. 1, extracted from injection/production data for more than 100 waterflooded reservoirs show much narrower range of variation than (c) the permeability-thickness product for the reservoirs in the database. The units for the x-axis are (a) bbl fluid/well/day, (b) bbl water/well/day and (c) mD-ft.](image)

3.2. Range of water injectivity index for individual wells

In addition to injection and production time series for reservoirs, the California database contains injection data by well that includes surface injection pressure. Over 2 million well-months of data with associated injection pressures are available. If we assume that the reservoir is at hydrostatic pressure and that friction losses in the injection tubing are negligible, then we can relate bottomhole pressure $P_{bh}$ to surface injection pressure $P_{wh}$ by $P_{bh} = P_{wh} + \rho_w \frac{gD}{U}$. If we assume that the average reservoir pressure remains at hydrostatic pressure $\rho_w gD$ during injection then the injection overpressure is given by $\Delta P = P_{bh} - \rho_w gD = P_{wh}$. Consequently for these wells we can avoid the assumption that all overpressures are the same, and instead compute the well injectivity index $II$ directly as

$$II = \frac{\text{Fluids Injected}}{\text{Well days on Injection} \times \text{Surface Injection Pressure}}.$$
Fig. 5. Cumulative frequency distribution of injectivity index for water injection wells in waterflooded reservoirs in California show much narrower range of values (two orders of magnitude) than the permeability-thickness product.

Figure 5 shows a cumulative frequency plot of $II$ for this large population of individual wells. We again see much less variation in the measured value of $II$ than in $kh$. The variation in this well-specific $II$ (most all values fall within two orders of magnitude) is quite similar to the width of the range obtained with the field-aggregate well-average rates in Figures 3 and 4. This supports the argument above that variation in the other quantities that influence $II$ and $PI$ is small compared to the variation in $kh$, and that engineering design tends to override and erase the influence of $kh$ on achievable rates of injection and production. Both $II$ and $kh$ are seen to have lognormal distributions, with significantly different variances. This indicates that variation in injection overpressure between reservoirs is not sufficient to explain the differences in dynamic range between $kh$ and the various values of $P_i$ and $P_p$ seen above.

3.3. Trend of proxies over time

As noted in Section 2, none of the reservoirs show a systematic variation in $P_p$ or $P_i$ over time. This is not surprising; the onset of waterflooding maintains the average reservoir pressure, so that the drawdown on production wells can be maintained. At the same time the injection overpressure will also remain relatively constant, since the bottomhole pressure will be limited by a nominal fracture threshold. In contrast, a reservoir that remains on primary production typically exhibits declining fluid production rates per well as the average reservoir pressure declines. The key point here for conventional GCS is that injection rates per well will decline over time because the average pressure in the storage formation will increase. The waterflooded reservoirs in this study do not show systematically decreasing injection rates per well because fluids are simultaneously being withdrawn from the reservoir.

This simple observation has an important implication for sustaining GCS rates. Extracting brine from the storage formation will ensure that desired injection rates can be sustained over long periods of time. Conversely, not extracting brine will cause injection rates to decrease over time. The rate of decrease will depend on specific features of the storage formation.

3.4. Injectivity in GCS projects

The data described above have two important implications for GCS injectivity. First, the $kh$ of the storage formation need not dictate the injection rate into the formation. Though variations in fluid and rock properties from one reservoir to the next contribute to this observation, the primary cause is implementing suitable reservoir engineering strategies. The production and injection data for waterflooded reservoirs in Figures 3, 4 and 5 confirm this attribution. The lack of correlation between $kh$ and the observed average rates of production and injection per well can only be the consequence of engineered well locations, completions and optimized operation. Like the per well average production and injection rates, the injectivity indices for individual wells in Fig. 5 show a much
narrower range than the range of reservoir $kh$. Thus the theoretical first order influence of $kh$ on individual well rates can be overcome with judicious operation of injection and extraction wells.

Second, the simultaneous extraction and injection of fluids enables rates to be sustained indefinitely. The waterflooded reservoirs in Figures 3 and 4 show no systematic decline in $P_i$ nor in $P_p$. Any process that only produces fluids or only injects fluids will inevitably exhibit declining rates with time, especially over the time scale of decades relevant to GCS. An exception to this rule is a formation that is hydraulically connected through a high permeability to an effectively infinite volume of brine. Such formations exist (they exhibit “very strong aquifer support” for producing oil reservoir) but are unlikely to be common enough to support large-scale GCS. The message of Figures 3-5 is that any storage formation can sustain large storage rates if extraction wells are operated appropriately.

4. Conclusions

Even with optimistic assumptions of the volumetric storage efficiency, an injection-only approach to GCS is unlikely to achieve overall storage rates large enough to mitigate CO$_2$ emissions. The limitations are due to the wide range of $kh$ values in geologic structures that would be good candidates for GCS and to the pressure buildup that must accompany brine displacement from the structure. The classical reservoir engineering strategy of waterflooding provides an alternative paradigm for GCS. The simultaneous operation of injection and extraction wells permits management of the average reservoir pressure and the sweep efficiency of injected fluid. Rates of fluid injection and extraction can be sustained indefinitely. Moreover broadly comparable rates of injection (within two orders of magnitude) can be achieved in reservoirs with a much wider range of $kh$ (more than four orders of magnitude) via engineering design. The injection+extraction paradigm can turn almost any structure into a viable GCS project, giving industry and government a much wider range of options for national, regional and local implementation of large scale GCS.

Acknowledgements

We are grateful to the sponsors of the Geological CO$_2$ Storage Industrial Affiliates Program at the Center for Petroleum and Geosystems Engineering at The University of Texas at Austin, and to sponsors of the CO$_2$ Capture Project (CCP3).

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