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Estimating the pressure-limited CO_2 injection and storage capacity of the United States saline formations: Effect of the presence of hydrocarbon reservoirs

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ABSTRACT

The U.S. Geological Survey (USGS) national assessment of carbon dioxide (CO_2) storage capacity evaluated 192 saline Storage Assessment Units (SAUs) in 33 U.S. onshore sedimentary basins that may be utilized for CO_2 storage (see USGS Circular 1386). Similar to many other available models, volumetric analysis was utilized to estimate the initial CO_2 injection and storage capacity of these SAUs based on aquifer characteristics and buoyant and residual trapping. The factor being almost always overlooked in most CO_2 storage capacity models is that many of the evaluated SAUs contain large numbers of both conventional and unconventional discovered and undiscovered oil and gas reservoirs. The hydrocarbon production and pressure distribution of the resident oil and gas reservoirs may be negatively influenced by the propagated CO_2 plume and pressure front resulting from a CO_2 injection and storage operation in the surrounding SAU.

To have a more realistic and accurate estimation of CO_2 injection and storage capacity in saline formations, a model was previously developed that considers the CO_2 injectivity of a given formation, underground pressure build-up limitations imposed by the rock fracturing pressure and the presence of hydrocarbon reservoirs within these aquifers. The developed method estimates the pre–brine extraction, pressure-limited CO_2 injection and storage capacity of a saline formation by applying 3D numerical simulation only on the effective injection area (A_{eff}) surrounding each CO_2 injection well utilizing TOUGH2-ECO2N simulation software.

In this work, we have identified and accounted for the existence of all hydrocarbon-bearing formations within a selected SAU by designating a buffer zone of no CO_2 injection and no induced pressure buildup around each hydrocarbon reservoir and only injecting CO_2 in the remaining SAU volume. Applying previously developed method, the pressure-limited CO_2 storage capacities of all U.S. SAUs are estimated in three scenarios: 1) ignoring the presence of oil and gas reservoirs, 2) accounting for the existence of oil and gas reservoirs, and 3) injecting CO_2 only in the SAUs without significant numbers of oil and gas reservoirs (defined as less than half of their area being covered by hydrocarbon-bearing formations). Under each of these three scenarios, the number of required wells, well spacing, and corresponding CO_2 injection rates are estimated and presented in detail for every SAU defined by the USGS national CO_2 storage assessment. Using this explained approach, the results indicate that the non-hydrocarbon sections of hydrocarbon-bearing SAUs in conjunction with other non-hydrocarbon-bearing SAUs may be capable of injecting and storing about 1.0 billion metric tonnes (gigatonnes, Gt) of CO_2 per year in the United States for 50 years without requiring pressure management techniques, such as brine extraction. The current approach can also be generally applied to any other saline formation with characteristics similar to those of the defined SAUs.

1. Introduction

Carbon dioxide (CO_2) injection and storage in underground saline formations is one of the most important methods to reduce CO_2 emission into the atmosphere. Even though most climate change prevention scenarios recommend developing a plan to replace fossil fuels with renewable, non-polluting energy sources worldwide (Energy Technology Perspective (ETP, 2012), it is predicted that fossil fuels will still play a major role in the energy sector for decades, mainly because it will not be possible to switch to completely non–fossil fuel energy production in a timely manner and at a reasonably acceptable cost

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(European Commission, 2013). Continued use of fossil fuels makes the problem of produced greenhouse gases (GHGs) and especially CO_2 emission into atmosphere and associated harmful effects on the climate very important.

In this regard, International Energy Agency (IEA) proposed two climate-change prevention scenarios: 1. 2 ° Celsius (2DS) and 2. Beyond 2DS (B2DS) that tend to suggest practical ways to reduce emission of GHGs into atmosphere to limit average global temperature change to 2 °C for 2DS and below 2 °C for B2DS scenarios (IEA, 2017). Based on the reported evaluations, the CO_2 Capture and Storage (CCS) will be responsible for up to 14% of reduction of global CO_2 emissions to meet 2DS and an additional 32% of the path from 2DS to B2DS by 2060 and beyond (IEA, 2017). Practically, it means that worldwide, by 2060, on average approximately 7.0 billion metric tonnes (gigatonnes, Gt) of CO_2 must be captured and stored each year to meet B2DS (IEA, 2017), as also emphasized at the 2015 Paris Climate Conference (Paris climate report, 2016). According to IEA forecasts, the United States should store 1.0 Gt/year of CO_2 (IEA, 2017). Note that the mentioned estimate is only based on the B2DS requirements. The current annual GHGs emissions in the United States are approximately 7.0 Gt of CO_2 equivalents (EPA, 2015), of which a high percentage would have to be eliminated by energy fuel switching and transformations to meet the B2DS requirements.

In this regard, CO_2 from anthropogenic sources used for enhanced oil recovery (EOR) has gained some attention during the last few years because the CO_2-EOR process produces additional oil from oil reservoirs while allowing some CO_2 to be stored within the reservoir structure. However, the additional oil recovery due to the CO_2-EOR operation is usually in the range of 5 to 15% of the original oil in place (OOIP) (Jahediesfanjani, 2017) for each amenable reservoir, so the corresponding CO_2 storage capacity volume of these reservoirs is at least an order of magnitude less than the billions of metric tonnes required for effective climate change mitigation (USGS CO_2 assessment team, 2013a, 2013b, and NETL, 2012).

Underground saline formations have been recommended as an alternative site for CO_2 storage due to their widespread availability and considerable capacity to hold and store CO_2.

Assuming that the required technology and infrastructure exists to capture and transport CO_2, an important concern is to estimate the most likely volume of CO_2 that can be injected and stored annually in U.S. underground saline formations, and to determine whether that volume is sufficient to meet the B2DS requirements (IEA, 2017). To more realistically and accurately model and estimate CO_2 injection and storage capacity in saline formations, we have developed a model that takes into account some limitations associated with the CO_2 injection into a given formation such as underground pressure build-up limitations imposed by the rock fracturing pressure and the presence of hydrocarbon reservoirs within these aquifers. The developed method estimates the pressure-limited CO_2 injection and storage capacity of a saline formation by applying 3D numerical simulation only on the effective injection area (A_{eff}) surrounding each CO_2 injection well utilizing TOUGH2-ECO2N simulation software. The result of applying this method is considered as further refinement of the estimates by USGS of CO_2 storage capacity in saline formations in the United States taking into account underground pressure limitations.

The next step in the process is to plan the number, spacing, and injection rates of CO_2 injection wells on a national level to safely accommodate the needed CO_2 underground storage capacity. The estimated storage capacity needs to be matched with large stationary sources that will be subject of one of our future investigations.

2. Literature review

Many researchers have developed models to estimate the ultimate capacity of a given saline formation to store and hold CO_2 (Bandilla et al., 2015). These models use different assumptions and understandings of the entire phenomenon, which results in highly variable estimates of potential storage capacity (Heidug, 2013). Many of the models estimate the CO_2 storage capacity of a given formation based on its pore volume and a CO_2 storage efficiency value (volumetric models). Bachu (2015) reviewed many of these models and evaluated the effects of various parameters on the estimated CO_2 storage efficiency under different reservoir and boundary conditions. These models define the saline formation as a homogeneous porous medium with uniform properties in which hydrodynamic and buoyancy forces must overcome viscous and capillary forces for the injected CO_2 plume to propagate into and through the saline formation. It is ultimately the rock, brine, and CO_2 conditions and properties that determine which force dominates and may affect the ultimate CO_2 storage efficiency. The estimated CO_2 storage efficiency is eventually used with the reservoir pore volume to estimate the CO_2 storage capacity of a saline formation (Celia et al., 2015).

There are several models in the literature that each report a different methodology to estimate saline formations' CO_2 injection and storage capacity at national or semi-national level. Some of these models are discussed here. For example, the U.S. Department of Energy (DOE) and the U.S. Geological Survey (USGS) have each developed a distinct, comprehensive method to estimate the national CO_2 storage capacity in saline formations by developing a different method to estimate ranges of appropriate CO_2 storage efficiency values. These models, along with the Szulczewski et al. (2012) model and a few others such as the Eccles et al. (2012) model, are reviewed below. All of these models are developed based on somewhat different assumptions and considerations and are fundamentally different from our proposed pressure-limited dynamic model that is based on CO_2 injectivity and underground fracture pressure limitations (Jahediesfanjani et al., 2017). Nevertheless, because these reports have reported CO_2 injection and storage capacity of major U.S. onshore saline formations, they are reviewed below.

As part of a national study, the U.S. DOE developed a method to estimate the capacity of the saline formations to hold and store CO_2 (Goodman et al., 2011) They incorporated the volumetric method to estimate the ultimate CO_2 capacity of a given saline formation, and estimated CO_2 storage efficiency assuming that net-to-gross thickness, effective-to-total porosity, volumetric displacement, and microscopic displacement can be represented by log-odds normal distributions at regional and national levels. Monte Carlo simulations were used to estimate saline formation storage efficiencies ranging from 0.40 to 5.5% for three different lithologies over the 10% and 90% probability ranges, respectively. The CO_2 capacity of a saline formation can be estimated by multiplying its estimated storage efficiency by its estimated pore volume. Utilizing the developed approach, the CO_2 storage capacity of saline formations throughout the United States was estimated to be 2300 and 22,000 Gt for the low and high estimates, respectively (NETL, 2012).

A similar method was developed by the USGS (USGS CO_2 assessment team, 2013a and 2013b) to estimate the CO_2 storage capacity of 192 storage assessment units (SAUs) in 33 sedimentary basins throughout the United States. In this previous model, the USGS national assessment team accounted for two mechanisms for CO_2 storage after injection: buoyant and residual trapping, each with a very different range of storage efficiency values. The model estimated fixed buoyant storage efficiencies using petroleum field observations and injection histories. The residual storage efficiencies were estimated using a relationship based on a capillary trapping number and mobility factor calculations, which required knowledge of CO_2 and brine residual saturations, viscosities, and relative permeability values (Brennan, 2014). Monte Carlo simulations (Blondes et al., 2013) were used to estimate the effect of uncertain parameters. The results were published as ranges of CO_2 storage capacity for each saline formation, with total national CO_2 storage capacity for all 192 SAUs ranging from 2000 to 4000 Gt based on 5% and 95% probability (P_5 and P_{95}) analyses, respectively