International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

A Review of CO_2 Behavior During Geological Storage and Leakage Assessment

Xiaohui Zhang[1], Boyun Guo[2]
[1,2]Department of Petroleum Engineering, University of Louisiana at Lafayette, PO Box 44690, Lafayette, LA, 70506

Abstract*— The increasing emission of CO_2 can cause Greenhouse effect and CO_2 has been a major challenge to the global environment. Carbon capture and storage (CCS) is an effective method of mitigation of Greenhouse effect. In this work, the important properties of CO_2 are introduced. The solubility of CO_2 in water and brine increases as pressure increases. The reaction between CO_2 and water will form carbonic acid. Also, some properties of CO2 will change with pressure and temperature and generally speaking, the injected CO_2 would be in a dense, supercritical phase in geologic sink. CO_2 geological storage can happen through different mechanisms- Solubility Trapping; Hydrodynamic Trapping; Chemical Trapping. The CO_2 storage capacity and injectivity can be evaluated through different methods based on different types of storage site. Depleted oil and gas reservoirs are the straightforward to estimate the storage capacity and injectivity due to the experience gained in so long history. Deep saline aquifers are believed to have the most potential to storage CO_2 but further studies have to be performed to evaluate the capacity and injectivity. Several case studies are shown about CO_2 storage capacity and injectivity. CO_2 leakage mechanisms determinate how CO_2 leaks form the geological sinks. Wells, consisting of different components, may provide the leakage pathways for CO_2. CO_2/Brine surface dissolution is a useful strategy which can increase the CO_2 storage efficiency. This strategy requires that additional wells should be drilled. But in current field practice, CO_2 is injected into abandoned wells.

***Keywords*— CO_2, Geological Storage, Leakage, Review.**

I. INTRODUCTION

The increasing emission of CO_2 can cause Greenhouse effect and CO_2 has been a major challenge to the global environment. Carbon capture and storage (CCS) is one of the options under investigation to reduce CO_2 emissions in the atmosphere [1][2]. There are well-documented options for CO_2 geological sequestration [3].

i. First, CO_2 can be used in enhanced oil recovery (EOR). For many years, the oil industry has injected CO_2 into oil reservoirs to increase the oil production. The CO_2-EOR accounts for 0.3% of world oil production. Utilizing petroleum processing exhaust CO_2 for EOR not only reduces greenhouse emissions but also confers commercial benefits.
ii. Second, CO_2 also can be used to enhance coal-bed methane recovery (ECBMR) or stored in deep unmineable coal seams.
iii. Third, CO_2 can be stored in depleted oil and gas reservoirs.
iv. Fourth, we can store CO_2 in deep unusable saline aquifers.

Besides, depleted shale-gas formations are also considered as a new type reservoir to enhance methane recovery with the co-benefit of CO_2 storage [4].

Table 1
Storage Capacity for CO_2 Storage in North America [5]

Formation Type	**10^9 metric tons**	**%**
Saline Aquifers	3,297 – 12,618	91.8 – 97.5
Unmineable Coal Seams	157 – 178	4.4 – 1.4
Mature Oil & Gas Reservoirs	138	3.8 – 1.1
Total Capacity	3,592 – 12,934	100

II. IMPORTANT PROPERTIES OF CO_2

a) Water Solubility

The reason we have to address the water solubility of CO_2 is that saline aquifer is believed to have the largest capacity for CO_2 geological sequestration (Table 1) [5]. The solubility of CO_2 in water and brine (Figure 1) progressively increases as pressure increases but decreases sharply as temperature and salinity increase [6].

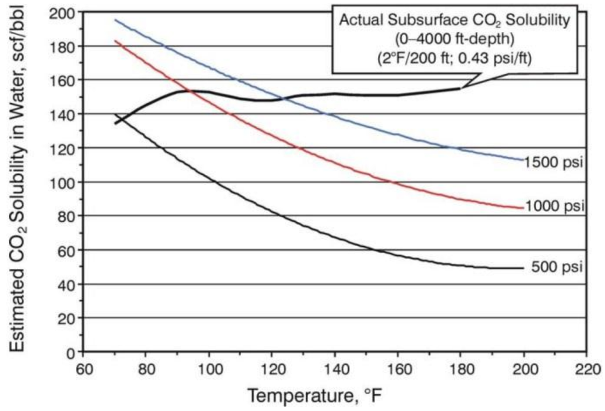

Figure 1 Variation of CO_2 solubility in water as a function of temperature and pressure [6]

b) Formation of Carbonic Acid

The reaction between CO_2 and water will form carbonic acid. Then the pH value will decrease and the acidic solution will corrode steel production casing [7].

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + CO_3^- \qquad \text{(Eq. 1)}$$

A brine solution containing 20% sodium chloride (NaCl) and dissolved CO_2 under 880 psi (6.1 MPa) at 113°F (45°C) has a pH value of around 3. At this low pH, the solution will be capable of leaching minerals and weakening the host formations used for geologic sequestration [8]. This very acidic solution can also readily destroy the cements used to seal injection well casing [9].

c) Density and Viscosity

Under surface condition, CO_2 is a colorless, odorless, noncombustible and relatively nonreactive gas. While under subsurface condition, some properties will change with pressure and temperature (Figure 2). For example, in an area with a 1.5°F/100ft (9.5°C/Km) geothermal gradient and a 0.43-psi/ft. (9.8-KPa/m) hydrostatic pressure gradient, the injected CO_2 would be in a dense, supercritical phase when the geologic sink was at a depth greater than approximately 2600 ft. (790 m) [6].

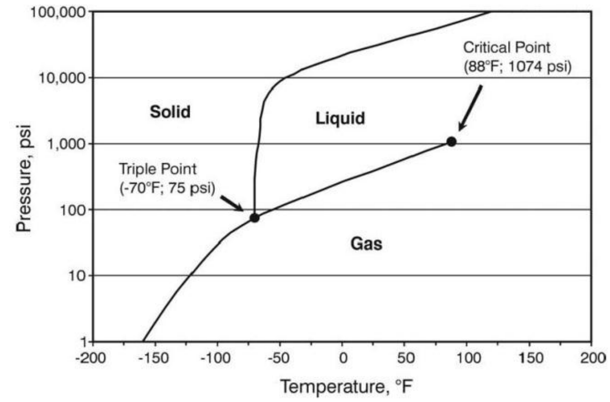

Figure 2 The phase diagram of CO_2

Generally speaking, in most geological sequestration condition, most part of CO_2 stays in its supercritical state and has a density (Figure 3) and viscosity (Figure 4) less than that of water. Thus the buoyancy will cause the CO_2 to migrate to the top of the injection zone. Only a portion of the injected supercritical CO_2 will dissolve in the aqueous phase. The net result will be a two-phase system of lower-density CO_2-rich fluid, which will flow upward, and a higher-density aqueous phase containing dissolved CO_2, which will flow downward [8][10].

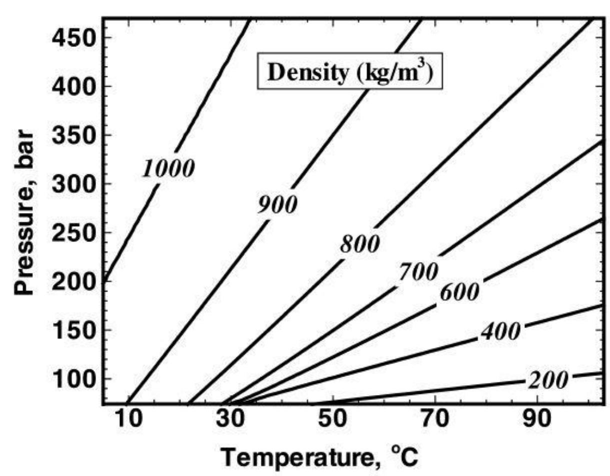

Figure 3 Contour diagram of CO_2 density [11]

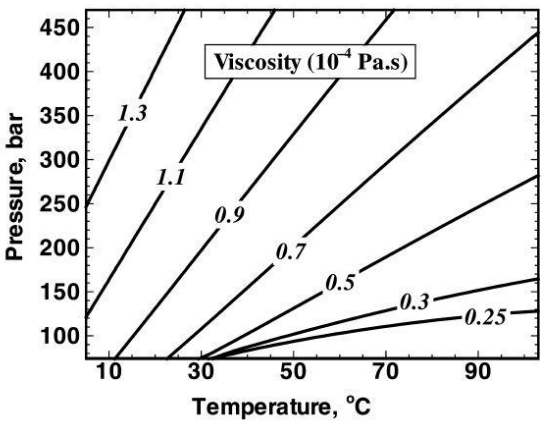

Figure 4 Contour diagram of CO_2 viscosity [11]

III. CO_2 Geological Trapping Mechanisms

The IPCC [12] report describes three main mechanisms for CO_2 storage (Figure 5).

i. Solubility Trapping. In solubility trapping, the CO_2 simply dissolves in the formation water or reacts with the water to form carbonic acid and other aqueous carbonate species.
ii. Hydrodynamic Trapping. In hydrodynamic trapping, CO_2 occupies the pore space of the rock comprising the geologic sink. The geologic sink for hydrodynamic trapping is a porous rock layer capped by an essentially impermeable rock layer. Other terms that are sometimes used to describe this type of trapping mechanism are structural and stratigraphic trapping [8].
iii. Chemical trapping in formation fluids (water/hydrocarbon) either by dissolution or by ionic trapping. Once dissolved, the CO_2 can react chemically with minerals in the formation (mineral trapping) or adsorb on the mineral surface (adsorption trapping).

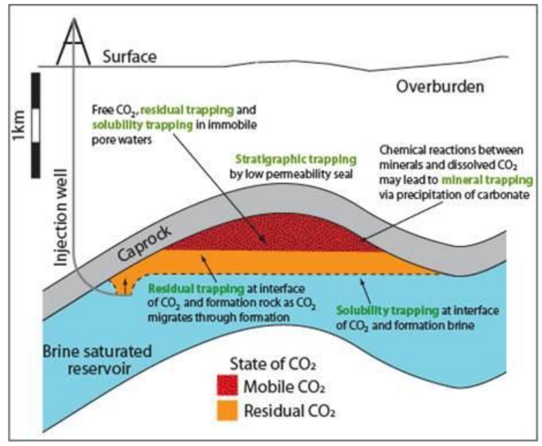

Figure 5 Three main mechanisms for CO_2 storage [12]

IV. CO_2 Storage Capacity And Injectivity

In the context of CO_2 geological storage, storage capacity and safety are two aspects to be evaluated in order to ensure the efficiency of this operation [13].

Bachu et al. [14] summarized the methodology of CO_2 storage and capacity estimation. In this work, the authors indicate that the CO_2 storage capacity estimation should be based on different storage site types: geological media, coal beds; oil and gas reservoirs; deep saline aquifers. Among all the storage site types, oil and gas reservoirs are the most straightforward to estimate the storage capacity because they are much better characterized. Therefore, the capacity for CO_2 storage in any particular region at any scale is given by the sum of the capacities in all the reservoirs in that area. In the case of CO_2-EOR, the storage capacity can be calculated on the basis of worldwide field experience of many years of CO_2-EOR, and through numerical simulation. But the identification of suitable CO_2-EOR reservoirs is a challenging problem. The calculation of storage capacity in coal beds is based on coal thickness and CO_2 adsorption isotherms. However, the identification of economic and suitable coal beds sites is a major challenge.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

Among all the storage site types, deep saline aquifer is believed to have the largest storage potential. However, evaluation of the CO_2 storage capacity in this kind of site is very complex due to the various trapping mechanisms. At last, the authors indicated the further efforts to evaluate the CO_2 storage capacity. First, sufficient data has to be collected, especially that of coal beds and deep saline aquifers. Second, more information about the physical and chemical processes and engineering aspects has to be gathered. Third, the interplay between various storage mechanisms acting of different time scales in deep saline aquifers has to be better understood.

Jin et al. [15] estimated the CO_2 storage capacity of two hypothetical near-shore storage sites (Lincs and Forth) in the UK. For each site, the author used different methods: static (compressibility) and dynamic (semianalytical semiclosed method and numerical simulation) methods. At both sites, the compressibility method gives lower storage efficiency values than the other two methods. This is because the compressibility method assumes a closed system and does not consider the pressure buildup at the wells. The advantages of numerical simulation method are that it can predict the amount of CO_2 dissolved or trapped at the pore scale (residual trapping), and that it can also indicates how freely CO_2 may migrate in aquifers, so that injectors and monitoring wells can be optimally placed to maximize the storage capacity and to minimize the risk of leakage.

Lindeberg et al. [16] studied the CO_2 storage capacity of Utsira formation via static volume method and reservoir simulation method. The 25,000 km^2 Utsira formation is the largest shallow aquifers in the North-Sea and it has been identified as one of the major aquifers for long-term storage of CO_2. The formation is already being used for CO_2 storage at Sleipner where 1 million ton of CO_2 per year is being injected. In simulation of injection with up to 210 injection wells distributed over the whole formation, the results show that 7% of the pore volume corresponding to 40 Gt CO_2. The effective utilization of the reservoir could be in the range of 20 to 60 Gt.

Szulczewski [17] conducted a model to evaluate the CO_2 storage capacity model and injection rate model and applied them to five individual reservoirs: 1) lower Potomac aquifer, 2) Lawson Formation and lower Keys Formation, 3) Mt. Simon Formation, 4) Madison Limestone and 5) Frio Formation. For these reservoirs, the range of storage capacities is 2.0 to 67.5 Gt of CO_2. The range of average storage capacities is 3.1 to 48.5 Gt of CO_2.

V. CO_2 LEAKAGE RISK MECHANISMS AND ASSESSMENT

If the CO_2 exists in reservoirs as a supercritical phase for thousands of years there is the potential that it could migrate out of the reservoir [18]. Before we assess the CO_2 leakage risk qualitively and quantitively, the CO_2 leakage mechanism should be addressed.

Three basic types of mechanisms could result in CO_2 leakage from geological formations [6].

The first mechanism is fast-flow path leakage which would primarily involve CO_2 movement up through poorly sealed or failed injection well casings and improperly abandoned wellbores and through transmissive faults or fractures in the cap rock above the geologic sink.

The second mechanism is slow leakage, which would primarily involve gas transport by diffusion processes and loss of dissolved CO_2 because of the hydrodynamic flow of formation water out of the geologic sink.

The third mechanism is leakage due to desorption of adsorbed-phase CO_2.

The CO_2 potential leakage pathways along an existing well are shown in Figure 6.

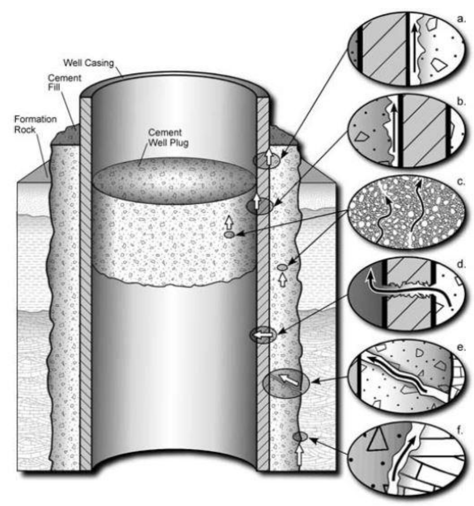

Figure 6 Potential leakage pathways along an existing well: between cement and casing (Path a and b), through the cement (c), through the casing (d), through fractures (e), and between cement and formation (f) [19]

Celia et al. [19] developed a computational model to research the risk of leakage versus injection depth. Different from traditional numerical models, this model has no spatial grid but rather uses analytical solutions in space. Then the authors identified the Wabamun Lake area southwest of Edmonton, Alberta, Canada and gathered types of data of 1344 oil and gas wells there.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

The results showed that the leakage risk decreases with the depth increasing. And the authors also indicated that the injection wells candidates should be chosen depends on the properties of these formations as well as the number of wells that penetrate the caprock of each of the formations. Therefore, the Nisku and the Basal Sandstone Formations are the two most promising formations for injection in this area.

Nordbotten et al. [20][21][22] developed a semi-analytical model to describe the behavior of CO_2 injected into saline aquifer (Figure 7).

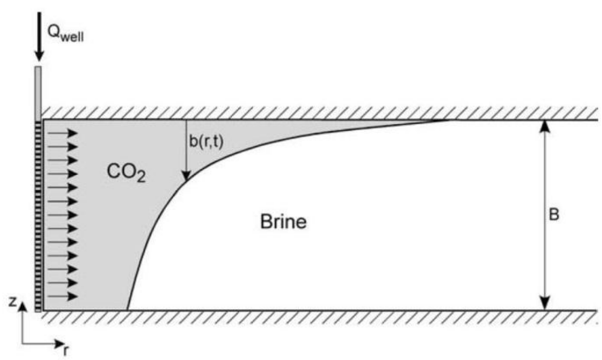

Figure 7 Typical profile of CO_2 plume defined by thickness

According to the solution to the semi-analytical model, the CO_2 profile can be described by the following equation.

$$\frac{b(r,t)}{B} = \frac{1}{\lambda_c - \lambda_w}\left[\sqrt{\frac{\lambda_c \lambda_w V(t)}{\varphi \pi B r^2}} - \lambda_w\right] \qquad \text{(Eq. 2)}$$

Where,

$b(r,t)$ =the thickness of the CO_2 plume at radial distance r and time t

$V(t)$ =the cumulative volume of injected fluid

λ_c =the mobility of CO_2

λ_w = the mobility of water (brine)

φ =porosity

B = is the thickness of the formation

Noh et al. [23] derived an analytical solution for 1-D two-phase semi-miscible displacement for CO_2 injecting into saline aquifers.

After CO_2 injection, injecting an undersaturated aqueous phase can push the CO_2 slug farther into the aquifer. When the aqueous phase displaces the gaseous phase, two shocks arise, with the residual gas saturation pervading the regions between the shocks. Thus, the calculated velocities of the fast and slow shocks indicate the amount of residual-saturation trapping. Because of the large solubility of CO_2 in water, the velocities of the fast and slow shock are comparable.

Le Guen et al. [24] proposed a risk-based approach for integrity and confinement performance management. The approach treats the wells as a system with components such as tubulars, cement sheaths, packers, cement plugs etc. Each component has its own function to the system. Several kinds of failure modes can defeat the functions of components (Table 2). Also, in this paper, the authors indicated that the cement sheath can be described as a porous media saturated with a water phase and a CO_2 phase. The transportation of CO_2 through the cement sheath is mainly governed by pressure gradient and capillary. The degradation of cement sheath can be described as the change in properties such as porosity and permeabilities.

Table 2
Functional Analysis - List of components, corresponding functions and possible failure modes with main causes and associated effects) [24]

Components	Function	Failure mode	Causes	Effects
Tubulars	(F1): to resist to formation fluids pressure	Loss in mechanical resistance	Corrosion	Breaking and collapse
	(F2): to ensure sealing with respect to formation fluids	Loss in sealing with respect to the formation fluids		Fluids can penetrate the well
	(F3): to resist to CO_2 pressure and temperature	Loss in mechanical resistance	Corrosion, erosion	Breaking and collapse
	(F4): to ensure sealing with respect to injected CO_2	Overpressure	Shrinkage due to temperature variation	Loss of bond between casing and cement
			Operator	Cracking of casing
		Loss in sealing with respect to the CO_2	Corrosion, erosion	CO_2 can penetrate the well
	(F5): to resist to formation pressure (creep)	Loss in mechanical resistance	Corrosion	Collapse and total effort transfer on cement sheaths
Cement	(F2): to ensure sealing with respect to formation fluids	Loss of sealing with respect to the formation fluids	Chemical degradation and/or leaching	Appreciable increase in permeability
	(F4): to ensure sealing with respect to injected CO_2	Loss of sealing with respect to the CO_2	Cracking	Severe increase in permeability
			Chemical degradation and/or leaching	Appreciable increase in permeability
	(F5): to resist to formation pressure (creep)	Loss in mechanical resistance	Loss of cement sheath and transfer of the efforts to the casings	Creep of the cement sheath

NETL [25] indicated that among all the factors contributing to loss of well control incidents, cement barriers plays an important role. This conclusion was concluded from the data of offshore operations in the Gulf of Mexico spanning 1992 to 2006. Also, NTEL assessed the research needs related to improving primary cement isolations of formation in deep offshore wells. These researches include monitor cement placement and cement integrity in the long term, cement stability under field conditions, cement quality control, design of cements for frequent stress loading and unloading events post placement, etc.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

Loizzo et al. [26] proposed a risk matrix to assess the CO_2 leakage risk through wellbores (Figure 8). This risk matrix is based on that the risk is generally defined as the product of the probability of an event and its severity. The authors also indicated that small leaks may be frequent for CO_2 injection wells and possibly 20% of all wells may be leaking at some point in their life. Also, the leakage risk is not uniform and it depends on a number of factors including the geology of the field.

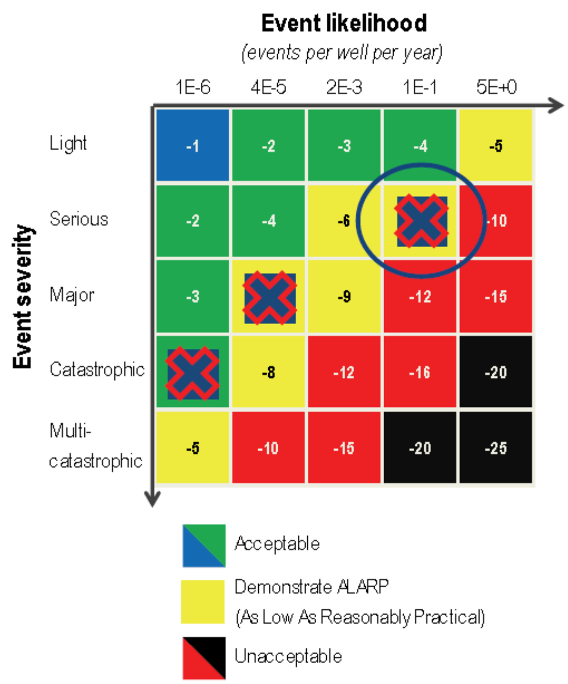

Figure 8 Assessment of CO_2 leakage risk through wellbores. Red crosses represent the joint frequency-severity for serious, major and catastrophic events. Numbers show risk values (product of severity by likelihood) for every matrix cell. The blue circle corresponds to the Maximum Criticality Severity, with a criticality value of -8 for Serious events (small surface leaks) [26]

Watson et al. [27] analyzed the factors that may contribute to CO_2 potential leakage based on data for more than 315,000 wells drilled up to the end of 2004 in the Province of Alberta. Then the factors were classified according to their levels of impact (Table 3).

Table 3
Factors classification according to level of impact [27]

Level of impact	Factors
No apparent impact	well age
	well-operational mode
	completion interval
	H_2S or CO_2 presence
Minor Impact	license
	surface-casing depth
	total depth
	well density
	topography
Major Impact	geographic area
	wellbore deviation
	well type
	abandonment method
	oil price, regulatory changes and SCVF/GM testing
	uncemented casing/hole annulus

VI. NUMERICAL SIMULATION RESEARCH

Mo et al. [28] used a black-oil reservoir simulator to model the long-term CO_2 storage in aquifer. The simulation result showed that the dissolution of CO_2 in aquifer water is the dominant mechanism of CO_2 storage in deep saline aquifers. Also, they found that the amount of trapped CO_2 gas due to the effect of gas-water capillary pressure and relative permeability hysteresis decreases when k_v/k_h increases.

Liu et al. [29] and Huo et al. [30][31] conducted several researches about CO_2 sequestration in saline formations using the simulation method. What should be noted is that they used Discrete Fracture Modeling (DFM) to represent the fractures individually and explicitly. And the results showed that the existence of caprock and mudstone layers could prevent injected CO_2 from leaking outside the saline aquifer when no fractures are present. However, fractures intersecting with mudstone layers will cause significant leakage increase as the fractures from extremely preferential pathways for CO_2 transport. Fracturing will help CO_2 moving horizontally. Hydraulic fractures, if not communicated with natural fractures, will not only help improve injectivity but also mitigate the leakage risk. But if they are close enough to natural fractures up out of the target formation, it may cause severe CO_2 leakage. Slop layers will help CO_2 move towards the upper direction.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

Bryant et al. [32] studied the mechanisms of "inject low and let rise" strategy of storing CO_2in deep saline aquifers. This strategy is to maximize the amount of CO_2 stored in immobile forms by letting CO_2 rise toward the top seal of the aquifer but not reach it. The authors used GEM-GHG simulator to study the influence of factors like heterogeneity, dip, capillary pressure and anisotropy. The simulation results showed that the heterogeneity of rock properties leads to channeling of the upward-moving CO_2. The intrinsic instability of a buoyancy-driven displacement does not appear to play a significant role in aquifers with heterogeneous rock properties.

Zhang et al. [33] studied the rock/CO_2/saline-formation-brine interaction during CO_2 injection into deep saline carbonate formations with simulation methods. They used the simulator TOUGHREACT with a Pitzer ion-interaction ionic-activity model to conduct the simulations. Besides the CO_2 plume and total CO_2 distribution after injection, which other researchers also studied on, the authors focus on the pH value change during injection and the mineralogical and rock-property change in the injected carbonate formation. The simulation results showed that the pH value changes from 5.5 before injection to approximately 3.1 near the wellbore and between 3 and 4 in the areas corresponding to the gas plume after injection. Other important phenomena are the dissolution of carbonate minerals and anhydrite minerals. The porosity decreases from 18% to 15-17% near wellbore because of halite precipitation. The authors indicated that carbonate formations are highly reactive with CO_2 and the injection period also should be paid attention to because it has effect of near-wellbore stability and CO_2 leakage.

Carey et al. [34] studied the cement/CO_2/brine interaction using simulation methods. The results show that supercritical CO_2 will not flow through good-quality cement because of the capillary properties of cement. In this case, leakage of CO_2 is confined to wellbore interfaces and carbonation of cement occurs by diffusion of CO_2 into the cement from the interface. These results complement field studies by Carey et al. [35] and Crow et al. [36] that indicate that the dominant potential leakages paths for CO_2 are along interfaces between cement and steel and between cement and caprock rather than through the cement itself.

Zhang et al. [37] developed an efficient parallel simulator for large-scale, long-term CO_2 geologic sequestration in saline aquifers.

This parallel simulator, based on the ECO_2N module of the general-purpose numerical simulation program TOUGH2 is a three-dimensional, fully implicit model that solves large, sparse linear systems arising from discretization of the partial differential equations for mass and energy balance in porous and fractured media. The simulation results of the 3D high-resolution model built by the simulator reveals that the multi-scale nature of convective mixing as an important process for the long-term fate of stored CO_2.

Nghiem et al. [38] conducted simulation study by GEM simulator to investigate the optimization strategy of trapping process for CO_2 Storage in Saline Aquifers. The results show that water injection could increase residual gas trapping and the total trapping could be maximized by adjusting the locations, injection rate and injection duration of water injectors.

Akaku [39] carried out a study of numerical simulations for the CO_2 storage using a conceptual, generic, simple 3D aquifer model without rapping structures. The results show that the mudstone barriers, which have relatively poor sealing efficiency, prevent the upward migration of CO_2 and help its lateral distribution. This suggests that the heterogeneities in the formation, particularly the distribution and properties of low permeability rocks, are very important to predict the movement of the injected CO_2. The results also show that even the gently dipping structures lead to upward migration of CO_2 plume. Finally, the simulation suggests that heterogeneous formation without structures can be a target for long-term CO_2 geological storage.

Pham et al. [40] assessed the CO_2 injection behavior of Utsira-Skade aquifer (North Sea, Norway) by numerical simulation method. The results showed that the CO_2 trapped by the dissolution trapping mechanism occupied a fraction of approximately 20% of the injected CO_2. CO_2 trapped in the residual trapping mechanism is approximately 3% and CO_2 trapped in the structural/stratigraphic trapping mechanism more or less 77% at the end of 50 years of injection. After about 8000 years after the injection period, the dissolved amount increase to nearly 70%, and residual trapping decreases to approximately 1%, while, mobile CO_2 decreased down to 29% of the total CO_2 amount injected.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

VII. CO_2/BRINE SURFACE DISSOLUTION STRATEGY

Eke et al. [41] compared four conceptual CO_2 injection strategies with commercial simulator Aspen HYSYS. The four strategies are standard CO_2 injection, CO_2/brine surface mixing and injection, CO_2/water surface mixing and injection, and CO_2-alternating-bring (CAB) injection. The simulations show that the CO_2/brine surface mixing and injection strategy can help enhance CO_2/brine solubility and improve CO_2 sequestration. Dissolving CO_2 into bring at surface facilities before injection produces a CO_2-saturated-brine stream with density slightly higher than the original brine in the formation. The denser CO_2-saturated-brine stream when injected into the formation is capable of eliminating the buoyancy force that is a strong driving force to bring CO_2 to the surface. Also, this strategy can speed up CO_2 immobilization because the period of time needed to achieve immobilization in the subsurface formation is reduced by the surface mixing vessel.

Akinnikawe et al. [42] proposed a method to avoid the aquifer pressurization problem which will cause insufficient CO_2 storage efficiency and excessive risk. The authors considered to produce the same volume of brine as is injected as CO_2 in a CO_2/brine displacement. The simulation study is based on the Woodbine aquifer in Texas. The results show that the displacement strategies increase the storage efficiency from 0.48% for the bulk-injection case to more than 7%. Different from traditional CO_2 storage strategy, the CO_2/brine-displacement strategy has to consider the issue of additional wells and disposal of produced brine.

Anchliya et al. [43] proposed an engineered system to reduce aquifer pressurization and accelerate CO_2 dissolution and trapping. Figure 9(b) shows the engineered system and Figure 9(a) describes a base case with only one horizontal CO_2 injection well. In the engineered system, one horizontal brine injection lies exactly above the horizontal CO_2 injection well to impede the upward movement of CO_2 toward the caprock. In addition, two brine-production wells are used on either side of the horizontal CO_2 injector at the bottom of the reservoir to provide a lateral pressure gradient to mobilize the injected CO_2 in the horizontal direction and enhance sweep efficiency in the horizontal direction. Simulation studies for example homogeneous and moderately heterogeneous permeability fields suggest that almost 90% of the CO_2 can be immobilized as early as 20 years after the cessation of injection.

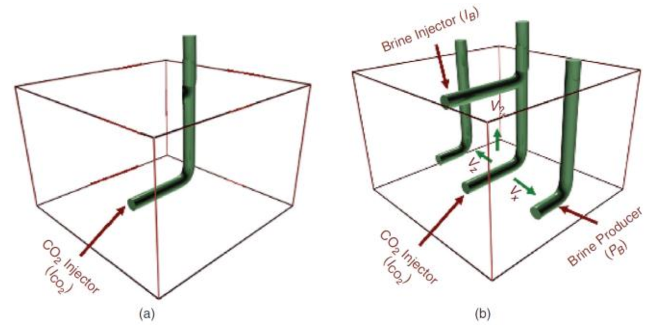

Figure 9 Base-case with one horizontal CO_2 injector (a) and engineered case with a horizontal CO_2 and a brine injector and two horizontal brine producers (b) [43]

Yalcinkaya et al. [44] conducted several experiments to study the effect of CO_2-saturated brine on the conductivity of wellbore cement fractures. The important of cement of CO_2 injection wells is that microfractures inside the wellbore cement and/or microannuli are possible pathways for CO_2 leakage to the surface and/or freshwater-aquifer leakage and could jeopardize safe and long-term containment of CO_2 in the subsurface. In the experiment, CO_2-saturated brine was injected into a 1×12-in. cement core at a flow rate of 2 mL/min under a net overburden pressure of 600 psi. The experiments consist of two parts: the low pressure (LP) experiment in which the injection pressure is 10 psi and the duration is 30 days, and the high pressure (HP) experiment in which the injection pressure is 1800 psi and the duration is 10 days. The results show that the porosity of the cement core decreases from 26% to 22% in LP experiment. But the porosity in HP experiment does not change significantly and it is possibly because of the short duration.

VIII. CONCLUSION AND DISCUSSION

The researches related to CO_2 capture and storage have been done with methods including computer simulations, field studies and laboratory at molecular to basin scales. Currently, the deep saline aquifer formation is the most potential CO_2 storage site due to its huge storage capacity. However, the disadvantage of this type of storage site is that the knowledge and experience people have mastered are not that much and more and more researches have to be conducted. Depleted oil and gas reservoirs are also playing an important role in CO_2 storage because people have gained over a century of experience in oil and gas development.

International Journal of Recent Development in Engineering and Technology
Website: www.ijrdet.com (ISSN 2347 - 6435 (Online)) Volume 3, Issue 4, October 2014)

Basically, the theory of CO_2/brine migration is still based on the Buckley–Leverett equation, which is used to describe two-phase flow in porous media. However, more considerations of the status of CO_2-supercritical, should be taken into the later researches. What's more, the mineral reaction and geochemical change are also important during and after CO_2 injection.

CO_2/Brine surface dissolution is a useful strategy which can increase the CO_2 storage efficiency. This strategy requires that additional wells should be drilled. But in current field practice, CO_2 is injected into abandoned wells.

Acknowledgements

This material is based upon work supported by the U.S. Department of Energy Office of Fossil Energy program under Award Number DE-FOA0000652.

REFERENCES

[1] House, K. Z.; Schrag, D. P.; Harvey, C. F.; Lackner, K. S.; 2006; Permanent Carbon Dioxide Storage in Deep-Sea Sediments. Proceedings of the National Academy of Sciences of the United States of America. 103 (33): 12291–12295

[2] Stefan, B.; 2008; CO_2 Storage in Geological Media: Role, Means, Status and Barriers to Deployment. Progress in Energy and Combustion Science. 34 (2): 254–273

[3] Nguyen, D.N.; 2003; Carbon Dioxide Geological Sequestration: Technical and Economic Reviews; SPE 81199; presented at the SPE/EPA/DOE Exploration and Production Environmental Conference held in San Antonio, Texas, U.S.A., 10–12 March 2003.

[4] CMI; 2013; 2013 Annual Report; Carbon Mitigation Initiative; Princeton University, 2014

[5] DOE, NETL; 2012; 2012 United States Carbon Utilization and Storage Atlas – Fourth Edition (Atlas IV); http://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/atlasiv/Atlas-IV-2012.pdf

[6] Nelson, Charles R.; Evans, James M.; Sorensen, James A.; Steadman, Edward N.; Harju, John A.; 2010; Factors Affecting The Potential For Co2 Leakage From Geologic Sinks; Plains CO2 Reduction (PCOR) Partnership; October 2005 http://www.undeerc.org/pcor/newsandpubs/pdf/FactorsAffectingPotential.pdf

[7] Allis, R.; Chidsey, T.; Gwynn, W.; Morgan, C.; White, S.; Adams, M.; and Moore, J., 2001, Natural CO2 reservoirs on the Colorado Plateau and Southern Rocky Mountains—candidates for CO2 sequestration, First National Conference on Carbon Sequestration, Washington, D.C., May 14–17, 2001

[8] White, C.M.; Straziser, B.R.; Granite, E.J.; Hoffman, J.S., and Pennline, H.W., 2005, Separation and capture of CO2 from large stationary sources and sequestration in geological formations—coalbeds and deep saline aquifers: Journal of the Air & Waste Management Association, v. 53, p. 645–715.

[9] Duguid, A.M.; Radonjic, R.; Bruant, T.; Mandecki, G.; Scherer, M., and Celia, M.A., 2004, The effect of CO2 sequestration on oil well cements, Princeton Environmental Institute, The Princeton papers at Vancouver GHGT-7

[10] Oldenburg, C.M., Unger, A.J.A., Hepple, R.P., and Jordan, P.D., 2002, On leakage and seepage from geological carbon sequestration sites: Lawrence Berkeley National Laboratory, Berkeley, California, U.S. Department of Energy Contract Number AC03-76SF00098

[11] Pruess, Karsten; Xu, Tianfu; Apps, John; Garcia, Julio; 2001; Numerical Modeling of Aquifer Disposal of CO2; SPE 66537; presented at the 2001 SPE/EPA/DOE Exploration & Production Environmental Conference, San Antonio, Texas, 26-28 February, 2001

[12] IPCC (Intergovernmental Panel on Climate Change) ; 2005; Carbon Capture and Storage; Cambridge University Press, 2005.

[13] Garrido, D.R.R.; Lafortune, S.; Souli, H.; Dubujet, P.; 2013; Impact of supercritical CO2/water interaction on the caprock nanoporous structure; Procedia Earth and Planetary Science 7 (2013) 738 – 741

[14] Bachu, Stefan; Bonijoly, Didier; Bradshaw, John; Burruss, Robert; Holloway, Sam; Christensen, Niels Peter; Mathiassen, Odd Magne; 2007; CO2 Storage capacity estimation: Methodology and gaps; International Journal of Greenhouse Gas Control I (2007) 430-443

[15] Jin, M.; Pickup, G.; Mackay, E.; Todd, A.; Sohrabi, M.; Monaghan, A.; Naylor, M.; 2012; Static and Dynamic Estimates of CO2-Storage Capacity in Two Saline Formations in the UK; SPE 131609; presented at the SPE EUROPEC/EAGE Annual Conference and Exhibition, Barcelona, Spain, 14–17 June 2010

[16] Lindeberg, E., Vuillaume, J.F., Ghaderi, A.; 2009; Determination of the CO2 storage capacity of the Utsira formation; Energy Procedia 1 (2009) Pages 2777–2784

[17] Szulczewski, M.L.; 2009; Storage Capacity and Injection Rate Estimates for CO2 Sequestration in Deep Saline Aquifers in the Conterminous United States; M.I.T. Master Thesis, May (2009).

[18] Gale, J.; 2004; Geological storage of CO2: What do we know, where are the gaps and what more needs to be done? Energy 29 (2004) 1329–1338

[19] Celia, M.A.; Bachu, S.; Nordbotten, J.M.; Gasda, S.E. and Dahle, H.K.; 2004; Quantitative estimation of CO2 leakage from geological storage—analytical models numerical models, and data needs: Princeton Environmental Institute, The Princeton papers at Vancouver GHGT-7, Paper ID #228

[20] Nordbotten, Jan Martin; Celia, Michael A.; 2012; Geological storage of CO2: modeling approaches for large-scale simulation; Published by John Wiley & Sons, Inc., Hoboken, New Jersey

[21] Nordbotten, Jan Martin; Celia, Michael A.; Bachu, Stefan; Dahle, Helge K.; 2005a; Semianalytical solution for CO2 leakage through an abandoned well; Environmental Science & Technolog 2005, 39, 602-611

[22] Nordbotten, Jan Martin; Celia,Michael A.; Bachu, Stefan; 2005b; Injection and storage of CO2 in deep saline aquifers: Analytical solution for CO2 plume evolution during injection; Transp Porous Med (2005) 58:339-360

[23] Noh, M.; Lake, L.W.; Bryant, S.L.; Araque-Martinez, A.; 2007; Implications of coupling fractional flow and geochemistry for CO2 injection in aquifers; SPE 89341; PRESENTED AT THE 2004 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, 17-21 April 2004

[24] Le Guen, Y.; Le Gouevec, J.; Chammas, R.; Gerard, B.; Poupard, O.; Van Der Beken, A.; Jammes, L.; 2008; CO2 Storage-Managing the risk associated with well leakage over long time scales; SPE 116424; Presented at the 2008 SPE Asia Pacific Oil & Gas Conference and Exhibition held in Perth, Australia, 20-22 October 2008

[25] NETL; 2012; An Assessment of Research Needs Related to Improving Primary Cement Isolation of Formations in Deep Offshore Wells; NETL-TRS-003-2012;http://netl.doe.gov/File%20Library/Research/onsite%20research/publications/NETL-TRS-003-2012_Cementing-Research-Needs_20121207.pdf

[26] Loizzo, M.; Akemu, O.A.P.; Jammes, L.; Desroches, J.; Lombardi, S.; Annunziatellis, A.; 2011; Quantifying the Risk of CO2 Leakage Through Wellbores; SPE 139635; presented at the SPE International Conference on CO2 Capture, Storage, and Utilization held in New Orleans, Louisiana, USA, 10–12 November 2010.

[27] Watson, T.L.; Bachu, S.; 2007; Evaluation of the Potential for Gas and CO2 Leakage Along Wellbores; SPE 106817; presented at the E&P Environmental and Safety Conference, Galveston, Texas, 5–7 March 2007

[28] Mo, S.; Akervoll, S.; 2005; Modeling Long-Term CO2 Storage in Aquifer with a Black-Oil Reservoir Simulator, SPE 93951, presented at the 2005 SPE/EPA/DOE Exploration and Production Environmental Conference held in Galveston, Texas, U.S.A., 7 – 9 March 2005

[29] Liu, X.; Gong, B.;2010; Numerical Simulation on CO2 Sequestration in Saline Formation with Natural or Hydraulic Fractures Using a Discrete Modeling Approach, CSUG/SPE 137621, presented at the Canadian Unconventional Resources & International Petroleum Conference held in Calgary, Alberta, Canada, 19-21 October 2010

[30] Huo, D.; Gong, B.; 2010a; Numerical Simulation on CO2 Leakage through Fractures along Wells Using Discrete Fracture Modeling, SPE 133986, presented at the SPE Asia Pacific Oil & Gas Conference and Exhibition held in Brisbane, Queensland, Australia, 18–20 October 2010

[31] Huo, D.; Gong, B.; 2010b; Discrete Modeling and Simulation on Potential Leakage through Fractures in CO2 Sequestration, SPE 135507, presented at the SPE Annual Technical Conference and Exhibition held in Florence, Italy, 19–22 September 2010

[32] Bryant, Steven L.; Lakshminarasimhan, Srivatsan; Pope, Gary A.; 2006; Buoyancy-dominated multiphase flow and its effect on geological sequestration of CO2; SPE 99938; presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, 22-26 April 2006

[33] Zhang, G.; Taberner, C.; Cartwright, L.; Xu, T.; 2011; Injection of supercritical CO2 into deep saline carbonate formations: Predictions from geochemical modeling; SPE 121272; presented at the EUROPEC/EAGE Conference and Exhibition, Amsterdam, 8-11 June 2009

[34] Carey, J.W.; Lichtner, P.C.; 2011; Computational studies of two-phase cement/CO2/brine interaction in wellbore environments; SPE 126666; presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, 2-4 November 2009

[35] Carey, J.W.; Wigand, M.; Chipera, S.J.; WoldeGabrel, G.; Pawar, R.; Lichtner, P.C.; 2007; Wehner, S.C.; Ranies, M.A.; Guthrie, G.D. Jr.; 2007; Analysis and performance of oil well cement with 30 years of CO2 exposure from the SACROC unit; West Texas, USA; International Journal of Greenhouse Gas Control 1 (1):75-85

[36] Crow, W.; Carey, J.W.; Gasda, S.; Williams, D.B.; Celia, M.; 2009; Wellbore integrity analysis of a natural CO2 producer; International Journal of Greenhouse Gas Control 4 (2):186-197

[37] Zhang, K.; Doughty, C.; Wu, Y.-S.; Pruess, K.; 2007; Efficient Parallel Simulation of CO2 Geologic Sequestration in Saline Aquifers; SPE 106206; presented at the SPE Symposium on Reservoir Simulation, Houston 26–28 February. doi: 10.2118/106026-MS.

[38] Nghiem, L.; Shrivastava, V.; Kohse, B.; Hassam, M.; Yang, C.; 2010; Simulation and Optimization of TrappingProcesses for CO2 Storage in Saline Aquifers SPE 139429; presentation at the 10th Canadian International Petroleum Conference (the 60th Annual Technical Meeting of the Petroleum Society), Calgary, 16-18 June, 2009

[39] Akaku, K.; 2008; Numerical Simulation of CO2 Storage in Aquifers without Trapping Structures; IPTC 12304; presented at the International Petroleum Technology Conference held in Kuala Lumpur, Malaysia, 3–5 December 2008

[40] Pham, V.T.H.; Riis, F.; Gjeldvik, I.T.; Halland, E.K.; Tappel, I.M.; Aagaard, P.; 2013; Assessment of CO2 injection into the south Utsira-Skade aquifer, the North Sea, Norway; Energy 55 (2013) 529-540

[41] Eke, Palu E.; Naylor M.; Haszeldine, S.; Curtis, A.; 2011; CO2/Brine surface dissolution and injection: CO2 storage enhancement; presented at the SPE Offshore Europe, Aberdeen, UK, 8-11 September2009

[42] Akinnikawe, O.; Chaudhary, A.; Vasquez, O.; Enih, C.; Ehlig-Economides, C. A.; 2013; Increasing CO2-Storage Efficiency Through a CO2/Brine-Displacement Approach; SPE 139467; presented at the SPE International Conference on CO2 Capture, Storage, and Utilization, New Orleans, 10–12 November 2010

[43] Anchliya, A.; Ehlig-Economides, C.; Jafarpour, B.; Aquifer Management To Accelerate CO2 Dissolution and Trapping; SPE 126688; presented at the 2009 SPE International Conference on CO2 Capture, Storage, and Utilization, San Diego, California, USA, 2–4 November 2009

[44] Yalcinkaya, T.; Radonjic, M.; Hughes, R. G.; Willson, C. S.; Ham, K.; 2011; The Effect of CO2-Saturated Brine on the Conductivity of Wellbore-Cement Fractures; SPE 139713; presented at the SPE international Conference on CO2 Capture, Storage, and Ulitization, New Orleans, Louisiana, USA, 10–12 November 2010