Economic Sustainability Modelling of Geological Carbon Sequestration in Saline Aquifers

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Keywords

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Summary

Storage of CO_2 in saline aquifers is an important strategy and a viable option for reducing the amount of CO_2 released to the atmosphere, hence to reduce the global warming. The paper presents an overall idea of CO_2 sequestration in saline aquifers including principles of CO_2 sequestration, CO_2 phase behavior, CO_2-water-rock interaction, and CO_2 trapping mechanisms. Then storage capacity and CO_2 injectivity are discussed as the main determinants of the storage potential of saline aquifers. Next, a site section process is addressed considering basin characteristics, reservoir characteristics, and economic and social concerns. Three main procedures are presented to investigate the suitability of a site for CO_2 sequestration, with site screening and detailed site characterization.

Introduction

Due the worldwide consumption of fossil fuels such as oil, natural gas, and coal as well as due to human activities, the concentration of CO_2 in the atmosphere is increasing day by day, which is about 280 ppm to more than 380 ppm over the last 250 years, and is now rising at a rate of about 1 ppm per year, leading to measurable global warming (Yang Fang, Bai Baojun, Tang Dazhen, Shari Dunn-Norman, David Wronkiewicz, 2010; Sprunt, 2006; IEA, 2008; USGS, 2008). Growing concerns about global warming and the challenge of CO_2 emissions regulation highlight the need to develop effective and economical means to sequester CO_2. Saline aquifers represent a promising way for CO2sequestration. Storage capacities of saline aquifers are very important around the world. Saline aquifers, defined as porous and permeable reservoir rocks containing saline fluid, are most promising because of their large capacity and broad distribution. The first field test was in the Sleipner West Field, North Sea. CO_2 has been injected into the Utsira Formation- a saline sandstone aquifer since 1996. In United Kingdom, Southern North Sea basin, East Irish Sea basin saline and North and central North Sea aquifers are considered as good candidate for CO_2 storage on the basis of following criteria: lithology (clean sandstone), porosity (>10%), depth (> 800m), Thickness (>20 m), Permeability (>200 mD), Salinity >30,000 mg/l (IEA 2008). Potential storage sites should be in a geologically stable area, as tectonic activity could create pathways for the CO_2 to migrate out of the reservoir through the cap rock (low permeability seal) into the overburden and potentially to surface. Saline aquifers can be

sandstones or limestones, but to be a potential storage reservoir for CO_2 they must fulfil those mentioned criteria. Therefore, the CO_2 sequestration and storage in saline aquifer requires systematic investigation. Reducing carbon emissions in a safe, effective, and economical manner requires an understanding of CO_2 sequestration mechanisms and considerations for potential storage sites.

The paper presents a general review of current status and concepts of CO_2 sequestration in saline aquifers as well as explains how CO_2 can be stored in saline aquifers and criteria of potential CO_2 storage site selection. Moreover, an attempt has been made to analyze the economic sustainability of the same.

CO_2 trapping mechanisms in aquifers

Storage of CO_2 in saline aquifers may be in both
"confined" and "unconfined" aquifers. Storage in confined aquifers depends on trapping of the CO_2 by structural (e.g. anticlines) and /or stratigraphic (e.g. sandstone pinchout, sandstone lenses) features, and is closely analogous to gas storage mechanisms of petroleum traps, or indeed to natural gas storage in subsurface aquifers.

CO_2 Phase Behavior:

The critical point is 31.1 °C and 7.38 MPa, at which CO_2 becomes a supercritical fluid (having high density like a liquid, but moves like a gas) which means it can be stored in great amounts and easily occupy an entire available space.
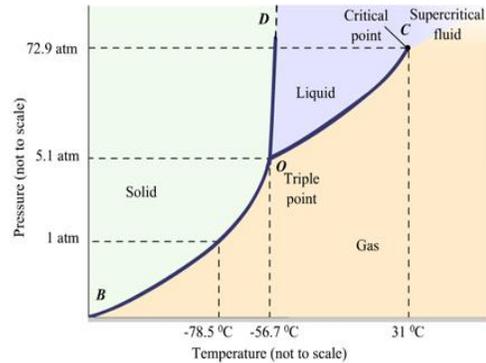

Figure 1: CO_2 Phase Diagram (IEA, 2008; Bachu, 2008)

The density of CO_2 stored underground depends on the pressure and temperature. Depending on the precise pressure and temperature conditions in the storage reservoir, CO_2 undergoes a relatively rapid change in density at depths between about 600 and 1000 m, becoming a dense phase supercritical fluid pather than a gas. As the gaseous and supercritical CO_2 are less dense than the water or brine in the void spaces of aquifers, they are buoyant relative to water or brine.
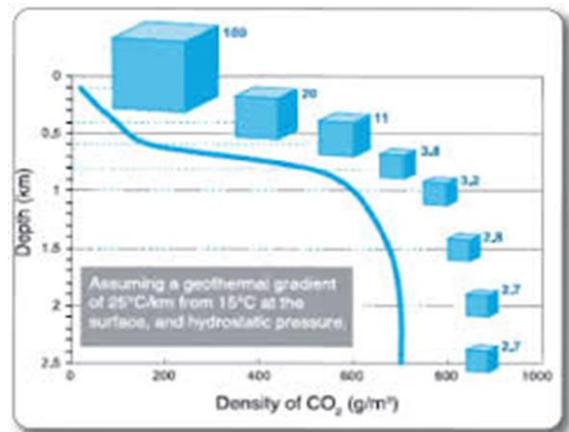

Figure 2: Density of CO2 vs. Depth under normal conditions (Kaldi and Gibson-Poole, 2008)

CO₂ Water-Rock Interaction:

Carbon Dioxide dissolves in formation water/brine. First, it simply dissolves. Then equilibrium is established between the dissolved CO_2 and carbonic acid H_2CO_3, which dissociates into HCO_3- and CO_3^{2-}.

Next, the carbonate anions interact with cations in the formation water such as Ca^{2+} and Mg^{2+} to precipitate carbonate minerals. Extensive deposits of Limestone and Dolomites have been formed this way.

The mutual solubility of CO_2 and brine affects the injection process and flow properties in three ways. First, CO_2 dissolves in brine increasing its density. Second, CO_2 dissolves in brine and reacts with water, forming an acid. Finally, H_2O dissolves into CO_2 increasing the salinity of brine (Hurtler et al. 2007).

In general, CO_2 solubility increases with increasing pressure and decreases with increasing temperature and brine salinity (Ulker et al. 2007).

When injected into the formation, CO_2 spreads in the porous medium, displacing formation water and occupying an increasing portion of the flow domain. It is then trapped through a combination of physical and chemical processes.

These processes are classified according to the coverage area: Geological trapping, Geochemical trapping and Hydrodynamic trapping. Structural and Stratigraphic trapping occurs when the free phase CO_2 is trapped by the structure of the formation and seal rock units.

Residual Saturation trapping occurs when CO_2 is trapped in pore space by capillary pressure forces.

Solubility and Ionic trapping occurs when CO_2 dissolves into the formation water.

Mineral trapping when CO_2 is involved in further chemical reactions with the rock matrix to form new stable minerals.

Migration trapping when very large masses of CO_2 could potentially be stored by this means, and migrates in the subsurface at extremely low velocities, reaching the surface after millions of years.

Storage Capacity:

It is an estimation of the amount of CO_2 that can be stored in geologic formations. It depends on pore volume, porosity and most importantly, microscopic and volumetric displacement efficiencies (Cinar et al. 2007; Bradshaw et al, 2007).

Factors affecting this are, Density of CO_2 at reservoir conditions, the interconnected pore space volume, and fluid property.

Solubility affects storage capacity significantly because it determines the amount of gas that dissolves in the brine.

The reactions among CO_2, brine, and the formation rock could change formation porosity and permeability (not affected by quartz, slightly affected by illite and kaolinite, and strongly affected by Calcite and Dolomite).

$$GCO_2 = A \ hg \ \phi tot \ p \ E$$

GCO_2 -> Mass estimate of saline formation CO_2 storage capacity

A -> Geographical area that defines the basin

hg -> Gross thickness of saline formation

ϕtot -> Average total porosity of entire saline formation

p -> Density of CO_2

E -> CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled, or connected, by CO_2

CO_2 Injectivity:

Injectivity measures the possibility of placing a fluid into a geologic formation, which contains the rate at which CO_2 can be injected and the ability of CO_2 to migrate from the injection well. It directly determines the suitability of a site for CO_2 storage.

Injectivity (I) is defined as the ratio of a well volumetric flow rate (q) to the corresponding pressure drop or flow potential (Δp):

$$I = q/\Delta p$$

As the volume of CO_2 builds up, the pressure required to place CO_2 into the formation gradually increases, and the injectivity decreases.

Injectivity is governed by permeability, relative permeability, rock fracture characteristics, and rock compressibility (Cinar et al. 2007).

Injectivity can be assessed by characterizing reservoir quality, geometry and connectivity, and CO_2 Water-Rock Interaction (Kaldi and Gibson-Poole, 2008).

Basin Type and Tectonic Setting: Site should be in relatively stable tectonic setting so that the stored CO_2 will not be released by tectonic movement. Preferred sedimentary basins are intracratonic, foreland, and passive-margin basins.

The basin flow system should be deep and regional in scale. Cold basins are more favorable than warm basins because they have low surface temperatures and geothermal gradients. Ideally, basin should be rich in energy resources, its hydrocarbon resources should be mostly recovered, and it should have advanced production.

Reservoir Characteristics:

Faults, fractures and unconformities are undesirable as they may create pathways for CO_2 to migrate through the cap rock to the surface (Hesse et al. 2006).

Cap rock, an impermeable low-porosity layer that prevents vertical CO_2 migration, provides the main trapping mechanism for long term storage security (Bentham and Kirby, 2005).

Size: The reservoir must be large enough to store the quantities of CO_2 planned, e.g. the life time emissions of one power plant (Bentham and Kirby, 2005).

A storage site is preferred to be deep enough to keep CO_2 supercritical so that a great amount of CO_2 can be stored. Bases on worldwide average conditions, an approximate minimum subsurface depth is about 800m (800-1,000m for cold basins, and 1,500-2,000m for warm basins) (Bentham and Kirby, 2005; Imbus et al. 2006). These parameters would maximize the capacity and minimize the cost of well drilling, CO_2 compression, and injection (Bachu, 2003).

Porosity and Permeability parameters must be sufficiently high to allow injection and provide sufficient volume for CO_2.

Fluid properties, such as, brine salinity and composition, viscosity, density, pressure and temperature, are fundamental parameters, that directly and strongly affect CO_2 phase, solubility, and dissolution, thus controlling

the effectiveness of trapping. Higher salinity results in lower solubility of CO_2.

Economic and social concerns (distance from CO_2 source, depth, accessibility, existing natural resources), site containment (seal capacity, thickness, trap type, fault), storage capacity (pore volume, size, CO_2 density), and Injectivity (permeability, porosity, thickness).

Injectivity (reservoir quality, geometry and connectivity, CO_2 water-rock interactions), containment (geomechanics, hydrodynamics, seal capacity), storage capacity (geological model, pore volume). Injection phase (injection rate, well design, injection strategy), post injection phase (long-term migration, dynamic flow behavior, ultimate destination and form, sweep efficiency and capacity). Socio-economic Characterization: Economics (cost of CO_2 compression, transport and injection), risks and uncertainty, monitoring and verification.

Inject CO_2 in a selected site and monitor CO_2 behavior, verification of formation properties, CO_2 saturation and distribution, etc.

The main issues affecting potential for injection of CO_2 in saline aquifers are the rate at which CO_2 can be disposed, the available storage capacity, the presence of a low permeability cap rock, the potential for CO_2 leakage, uncertainty and possibility of failure due to incomplete knowledge of subsurface conditions, and the corrosion resistance of materials to be used in the system. Factors that influence storage capacity and should be determined are well typed, injection rate, CO_2 purity, and injection strategy.

Vertical wells are commonly used for CO_2 injection. But if the geology characteristic of a CO_2 storage site can be well described, horizontal wells are desirable.

Two advantages over vertical wells are: large volume of CO_2 can be stored without reaching the top of the aquifer, and a higher injection rate can be expected. Horizontal wells can significantly improve injectivity and storage capacity-especially in low permeability formations.

Status of CCS in India

Although India ratified the Kyoto Protocol in August 2002, as a non-Annex 1 country, it does not currently have binding GHG emissions reduction targets under international law. Coal is expected to remain the dominant energy source in India through at least 2050 (TERI, 2006).

The IEA predicts that India will be in the top three emitters of the world by 2030 in terms of total CO_2 emitted each year. J. Condor et al. / Energy Procedia 4 (2011) 6125–6132 6127 4 Condor, J; Unatrakarn, D.; Asghari, K.; Wilson, M./ Energy Procedia 00 (2010) 000–000 According to Cleantech Group, about 80% of the electricity supplied to homes, farms and factories in India comes from coal-fired generation plants, one third of which are old, inefficient, and emit harmful gases. If all these were modernized it would reduce emissions by 10 million to 13 million metric tons of CO_2 equivalent each year (Razwan Maximiuc, 2009).

To date, the Government of India has not introduced any policies or legislation

dedicated to encouraging the development of CCS and as a matter of fact, currently this technology is not a priority. Industry stakeholders indicated that the governments of developed countries should contribute initial financing to CCS projects in India through international financing institutions such as the World Bank, the IMF, and the ADB. The resources for adaptation and mitigation of climate change will be provided from the budgets of the remaining years of the 11th Five Year Plan (2007-2012) and through to the end of the 12th Five Year Plan (2013-2017) (Sibley, 2009; Kapila, 2009).

Other initiatives include partnerships with US labs such as NETL in the Big Sky Carbon Sequestration Partnership (BSCSP), the CO_2 Geological Storage Project (CO_2GSP) partnership with the Pacific Northwest National Lab, the Integrated Research and Action for Development (IRADe), and the Institute of reservoir Studies.

At present, there is limited knowledge in geological capacity due to a general lack of essential data. Initial attempts at evaluating the storage potential in India were made by Singh and estimated that roughly 5 Gt CO_2 could be stored in unmineable coal seams, 7 Gt in depleted oil and gas reservoirs, 360 Gt in offshore and onshore deep saline aquifers, and 200 Gt via mineralization in basalt rock (McGrail, B. P., H. T. Schaef, A. M. Ho, Y., J. Dooley and C. L. Davidson, 2006). These capacity, however, are far from centers of emissions and may increase the cost of transportation.

Regarding to legislation, India does not have any integrated policies dedicated to encouraging the development of CCS. The National CDM Authority of the Ministry of Environment and Forestry, Government of India has initiated executive moves to investigate the potential of CCS. Analysts are of the view that linking CCS with the CDM is necessary before India can support the inclusion of CCS under the CDM umbrella (GCCSI, 2009).

Conclusion

Saline aquifers provide enormous capacity for CO_2 sequestration in most sedimentary basins worldwide. The characteristics of saline aquifers for CO_2 sequestration can be summarized as follows:

1) Carbon dioxide can be stored in saline aquifers through geological trapping, geochemical trapping, and hydrodynamic trapping. The potential for CO_2 storage in saline aquifers is largely determined by storage capacity and CO_2 injectivity. Storage capacity depends on aquifer volume, porosity, and displacement efficiencies, while CO_2 injectivity is governed by permeability, porosity, relative permeability, rock fracture characteristics, and rock compressibility. Evaluation of CO_2 storage capacity in saline aquifers is complex, due to limited data and various trapping mechanisms involved that act on different time scales. The mutual solubility of CO_2 and brine strongly affect storage capacity and injectivity. Chemical reactions among CO_2, brine, and formation rock affect the long-term fate of CO_2, although their impact is less significant.

2) Potential storage sites can be selected by assessing the basin and reservoir characteristics, as well as economic and social factors. Three main procedures are

site screening, detailed site characterization, and pilot field-scale test. These procedures can be done by using traditional site characterization methods, laboratory experiments, and numerical simulation. A site suitable for CO_2 storage should be in a geologically stable area and minimally faulted, fractured, or folded. It should have strong confining seals and adequate size, depth, permeability, and porosity. The ideal site would be a confining unit in a cold basin with strongly harmonious sedimentary sequences and no significant diagenesis. It would be deeper than 800 m, well characterized, and easy to operate.

3) Engineering factors such as well type, injection rate, CO_2 purity, and injection strategy must be considered. Horizontal wells can achieve larger storage volumes of CO_2 and higher injection rate than vertical wells. Lower injection rates can increase storage capacity and efficiency. Higher purity of the injection CO_2 results in a greater storage capacity. Brine injection as well benefits storage during CO_2 injection.

In India, regions of Haryana, Punjab, Gujarat, Orissa and Rajasthan are rich in saline aquifers which can be useful for CO_2 Sequestration.

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